Predictive Maintenance Program Design and Implementation

for

West Delta Production Company
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Reengineering Project

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Prepared For:

Prepared By:

USAID-EGYPT/NEXANT-USA/IIE-USA

INSTITUTE OF INTERNATIONAL EDUCATION
1400 K St., N.W., Washington, DC 20005
Introduction

Predictive maintenance and diagnostic techniques have the capability to reduce partial and full forced outages thus allowing more efficient operation of generating equipment, extending the useful life of the equipment and reducing capital and maintenance cost. Some Egyptian power plants have already started predictive maintenance programs and have seen the benefits. Other power plants can do the same.

Forced equipment outages usually result in damage to equipment. For instance, a bearing failure could lead to rotor damage, impeller damage or motor winding damage. If the bearing is replaced before it fails this damage can be avoided. This will result in a shorter outage time for the equipment, longer operating time and increased efficiency.

A high forced outage rate and lower reliability results in the need for larger amounts of spinning reserve thus reducing the average load for all generating plants in the system. As the average load drops, the heat rate increases, the efficiency decreases and a greater amount of fuel is burned than is necessary. This drives up fuel usage and air pollution. Predictive maintenance techniques have the ability to detect the onset of equipment problems early enough to schedule repairs at a convenient time. It also can allow equipment normally taken out of service after a set period of time such as every 12 months or a set period of operating time such as 10,000 hrs., to be operated longer. The duration between inspections may be increased resulting in increased generation without the addition of new units.

Predictive maintenance reduces costs in two ways. First, only the parts that have worn out or reached the end of life are replaced. Since damage as a result of failure is deceased or eliminated, the life of the equipment is often extended. Second, the elimination or reduction of forced outages allows equipment to operate for a greater number of years, thus postponing the capital expense of early replacement.

Some of the electric production companies in Egypt already enjoy of some of the benefits of a predictive maintenance by using predictive techniques (oil analysis and vibration monitoring and analysis). Some power plants such as Shoubra El-Kheima and Cairo West have had predictive maintenance programs for several years now. However, these techniques are not being fully utilized and there is definitely an opportunity to do more.

This text explains how to justify, budget, staff and equip a predictive maintenance program. It then describes how to implement a program with details on how to determine the equipment to monitor and how often. In addition, some old and new predictive maintenance techniques are described.
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1.1 Introduction

In a great number of power plants, maintenance consists of performing breakdown maintenance (corrective) and scheduled preventive maintenance. Preventive maintenance is scheduled according to time intervals and machines are inspected and parts replaced even if they are in good condition. Equipment failure may occur after an unnecessary inspection because of improper assembly. Predictive maintenance is based on the regular evaluation of machine and equipment condition and a determination of when the machine will wear out or fail.

1.1.1 Predictive Maintenance Philosophy

The general philosophy of a predictive maintenance program is to perform maintenance on equipment only when required, without sacrificing machine reliability.

A predictive maintenance program attempts to evaluate the present operating condition of equipment or components prior to a scheduled maintenance outage and determine specific maintenance requirements. This evaluation determines whether the equipment will operate reliably until the next scheduled outage. If maintenance is required, the predictive evaluation helps determine what specific maintenance is necessary. The evaluation may indicate that no maintenance is expected to be required at the next scheduled maintenance outage. This means that limited maintenance resources (money and spare parts) are used only as necessary. Time is still a very important part of predictive maintenance since predictive maintenance techniques attempt to predict when equipment will fail to perform as specified and when maintenance will be needed. However, a predictive maintenance program cannot predict the exact time that equipment will wear out or fail. High reliability demands that the maintenance be performed before that point is reached, especially for critical equipment.
1.1.2 Setting Goals

Any program or course of action that is undertaken must have a goal or series of goals to accomplish. Goal setting accomplishes two things:

- Helps to focus the efforts of all the individuals involved in the program
- Provides a readily measurable indication of how well the program is doing.

Goal setting should involve as many individuals involved with the program as possible. At least one representative of each group involved must be involved in setting the goals. This provides "ownership" and involvement. It also helps to ensure that goals are reasonable and attainable. Goals developed in a vacuum too often tend to be unrealistic or over ambitious.

Goals need to be realistic and attainable and should be modest for a beginning program. The temptation to set unrealistically high goals to justify a quick return of additional cost should be resisted. A predictive program that pays back the original costs sooner that projected will have a much higher chance of continued support than one that takes longer to deliver the promised benefits.

Predictive maintenance goals should also be tied into company and station goals whenever possible.

Goals can be set based on various objectives. There are no right or wrong goals. However, the goals should be based on the effects of the predictive maintenance program even though there may be some additional side benefits. For instance, improved equipment reliability for base load units typically results in lower heat rates. However, lower heat rate would not be realistic goal for a predictive maintenance program. Some appropriate goals are as follows:

- Maximize the use of equipment and parts without jeopardizing machine reliability.
- Accurately predict and schedule maintenance work.
Minimize outage time.

Maximize production.

Conserve resources by performing equipment overhauls on an as-required basis rather than on a calendar frequency or based on hours of operation.

Complete maintenance work within budget.

Improve the efficient use of maintenance resources by scheduling corrective maintenance when a potential failure is observed rather than performing unscheduled maintenance when a component fails.

Reduce the frequency of unexpected equipment failures.

Reduce the forced outage rate.

Maintain plant equipment in efficient condition.

Identify the condition of a component requiring investigation or repair before that component undergoes a loss of function.

Predictive maintenance is not easy and requires increased work and risk. Breakdowns may still occur if the intervals selected do not take into account all the possible failure modes. This results in lower production and increased maintenance costs for parts and overtime.

1.2 Justification

1.2.1 Introduction

Development and implementation of a Predictive Maintenance (PDM) program requires strong support and commitment from management. Without this commitment, it is almost impossible to have an effective program. This support must go beyond the authorization of funds. This commitment must embrace the entire concept of the value of predictive maintenance. The most effective justification of a PDM program
demonstrates the return on investment - how the savings offset the cost of the program. This section explains how to gather information and use it to show how the savings compare to the costs and hopefully show that PDM is cost effective and valuable.

1.2.2 Sources of Data

In the effort to gain management support, you have at your disposal various sources of data. Management must become believers that predictive maintenance is an effective tool. It is your job to convince them. You must also convince management that you know how to establish and operate a PDM program. Here are sources of data to present to management in support for the development of your program:

- PDM Philosophy
- Benefits of a PDM Program
- PDM Program Goals
- Corporate Goals
- Cost Benefit Analysis Data
- Satisfaction of Regulatory and Industry Requirements
- Case Histories (Your Plant and Industry-Wide)

The following items must be well-planned and developed in order to gain management support:

- Overall PDM Program Plan
- Communication Tools
  - Reports
  - Newsletters
  - General Training Programs and Seminars

1.2.3 Justification Factors

Justification of a PDM program involves two factors:

- Money
For a program to succeed and be of benefit, it must be supported by management. To gain this support you must justify the program. This means determining the costs of the program and the expected savings. While the other benefits are very important, it is the lack of a good cost justification that will stall or kill a program.

You have to show that it makes good economic sense, that PDM is a good economic tool. The chief advantage of predictive maintenance over other maintenance techniques is that it saves you money in maintenance and insurance costs as well as increased equipment running time. The results of implementing a PDM program are dramatic when you calculate the cost of plant downtime. When this comparison is made, management realizes the value of the PDM program.

In formulating your justification, you should show the potential savings as they apply to your operation in the following areas:

- Reduced Breakdowns
- Reduced Spare Parts Costs
- Reduced Unplanned Downtime
- Fewer Unnecessary Repairs

1.2.4 Cost Analysis Technique

Many methods are available and used to perform a cost analysis. The process can get quite cumbersome and can require a significant amount of historical data to perform. Often time and data are not available. In this situation, the people performing the cost analysis must abbreviate the process to meet and suit their needs. The key to performing a cost analysis is to be consistent throughout. The numbers at the end will rank and prioritize the tasks, and the only remaining decision will be to determine what to do first.
The cost analysis method presented here can be altered to suit your needs. The process illustrates straight-forward calculations and then applies a probability of failure factor, which can be very useful in calculating costs and prioritizing tasks.

1.2.5 Cost Analysis Elements

The first step in a cost analysis is to define the basic elements. These elements are the cost factors involved in performing the task; or not performing the task. The elements are presented below and then described further in the following paragraphs.

- Maintenance Cost - Both Predictive (PDM) and Corrective (CM)
- Availability Cost (AC)
- Equipment Cost (E)

It is important to review and account for these costs over a common time frame (for most cases this is annually). However, there will be instances when the interval should be extended due to longer run times. Each element can be reviewed over the total number of years for which data is available and then annualized by dividing by the years.

*Maintenance Cost*

This element includes both corrective and predictive maintenance costs. These costs include labor, tools, special equipment, and spare parts.

Normally, this element is divided into predictive and corrective costs. Corrective maintenance normally requires more labor and parts since a component failure often causes additional damage to the equipment.
**Availability Cost**

The availability cost (AC) is the cost of having to reduce load or shut down a generating unit. It is based on the cost of replacement power over the time required to complete the maintenance. The total time required includes downtime while waiting for spare parts. Availability is not normally considered for preventive or predictive maintenance accomplished during an outage unless the outage is extended for those tasks. If corrective maintenance is accomplished during a planned outage, it should not be considered unless it resulted in loss of generating capacity prior to the outage. Each availability analysis should be considered on a case by case basis.

When calculating the availability cost, several factors have to be taken into account. These factors are the amount of generation that will be lost, how long it will be lost, the unit capacity factor and the cost of replacement power (if needed). These factors are used to approximately calculate availability cost using the following equation:

\[
AC = \text{Lost Capacity (MW)} \times \text{Hrs.} \times \text{Capacity Factor (\%)} \times \text{Replacement Power ($/MWh)}
\]

**Capacity Factor** = \( \frac{\text{Yearly Generation (MWh)}}{\text{Rated Unit Output (MW)}} \times 8,760 \text{ Hrs.} \)

Capacity factor will never be 100%, even for a base load unit, since full load will not be required on weekends, early morning hours, holidays, etc.

Replacement power cost is the difference between the unit generation cost and the cost to generate the power on other units. In some cases this could be a negative. In other words, the replacement power may be less than the cost of generation on the unit.

**Equipment Cost**

Equipment cost is the cost of replacing the equipment divided by the number of years the equipment is expected to last before it needs to be replaced. An effective PDM program should prevent premature replacement or extend the life of the equipment.
1.2.6 Using the Cost Analysis Elements

The elements are used to compare the cost of the present maintenance program to the cost of the predictive program. That is, for each task the predictive maintenance process identifies, the elements are summed and compared to the sum of the present maintenance costs. For new equipment they would be compared to the expected maintenance costs. For example, the manufactures' recommended maintenance cost. This comparison can be expressed as:

\[ \text{PM}_p + \text{CM}_p + \text{A}_p + \text{E}_p \ < \ > \ \text{PDM}_t + \text{CM}_t + \text{A}_t + \text{E}_t \]

where:

- \( \text{PM}_p \) = Cost of Present Maintenance Program
- \( \text{CM}_p \) = Cost of Corrective Action in Present Program
- \( \text{A}_p \) = Availability Cost of Present Program
- \( \text{E}_p \) = Equipment Cost of Present Program
- \( \text{PDM}_t \) = Cost of Predictive (Future) Maintenance Program
- \( \text{CM}_t \) = Cost of Corrective Action in Future Program
- \( \text{A}_t \) = Availability Cost of Future Program
- \( \text{E}_t \) = Equipment Cost of Future Program

This comparison may be used when there is no predictive maintenance task being accomplished and one is being considered. The comparison may also be used when the frequency of a maintenance task is being changed. In some cases it may be straight-forward to sum the elements on both sides of the equation and arrive at an answer, but in other cases, probability factors will need to be applied.
Probability factors are used to establish the "future" plant costs. The probability factors can be calculated after an engineering assessment of failure probabilities. The equation then becomes:

\[ PM_p + P_p (CM_p) + A_p + E_p < > PDM_t + P_t (CM_t) + P (A_t) + P (E_t) \]

where:
- \( P_p = \) Probability of Failure (Present Program)
- \( P_t = \) Probability of Failure (Future Program)
- \( P = \) \( P_t / P_p \)

Although the formula looks complex, it is really just a summation of the costs previously discussed. The cost tabulation can be arranged vertically if convenient. The cost elements are calculated individually.

The following example shows how to use these elements to evaluate the cost effectiveness of a predictive maintenance program for a 100 horsepower motor. The motor drives a pump and is usually covered with dust and dirt. Although the dust and dirt are occasionally cleaned off the motor casing, the motor is never disassembled and cleaned. The motor fails after 2-1/2 years, is rewound and is scheduled to be replaced if it fails again (another 2-1/2 years).

The manufacturer says that the motor should last twenty five years with periodic cleaning. In addition, they recommend that the motor be tested once a year to determine the condition of the insulation. Since the motor drives a waste water pump and there is a spare motor available, there is no lost generation. This example shows how to calculate the cost analysis elements and evaluate the proposed predictive/preventive maintenance program.

\[ PM_p = 0 \]
\[ CM_p = $50,000 \text{ (for 1 rewind)} \]
\[ A_p = 0 \text{ (spare motor)} \]
\[ E_p = $100,000 \text{ motor lasts 5 years} \]

► PDM can extend life to 25 years with one rewind.
► PDM consists of cleaning and measuring insulation resistance once a year
Present Costs | Future Costs
---|---
PM\(p\) = 0 | PDM\(f\) = $2,000/yr
CM\(p\) = $50,000/5 = $10,000 | CM\(f\) = $50,000/25 = $2,000/yr
A\(p\) = 0 | A\(f\) = 0
E\(p\) = $100,000/5 = $20,000 | E\(f\) = $100,000/25 = $4,000
Total = $30,000/yr | Total = $8,000/yr

In this case the predictive/preventive maintenance program would be cost justified on an annual basis. This example assumed that the insulation tester was available and that the only additional cost would be the labor cost to partially disassemble the motor to clean and test it. Notice, however that the savings are due to the extended life of the motor and the elimination of frequent rewinds and motor replacements. The annual out-of-pocket cost will initially increase by $2,000. This initial increase is not unusual and will often be used as a reason to not approve a PDM program. However, the total maintenance cost at the end of 3 years is $6,000. At that point the motor would be rewound at a cost of $50,000, so the third year is the first time that the maintenance department would see an actual saving.

**Using Weighting Factors**

The example used some assessments of the probability of motor failure. These assessments can be quantified and substituted back into the formula and the results will be the same. It was predicted that there would be at least one motor rewind every 2-1/2 years and that the motor would be replaced every five years. In addition, it is projected that, even with the predictive/preventive program, there would at least one rewind required over the 25 year life of the motor. These probability assessments are calculated as follows:

\[
\begin{align*}
\text{P}_p &= 1/5 = .20 \\
\text{P}_f &= 1/25 = .04 \\
\text{P} &= .04 = .20
\end{align*}
\]

These values can be substituted into the following formula:
The result is identical to the one we first obtained. There is one consideration to be careful about when conducting this analysis. It would be easy to assume that the new program would eliminate all future failures, thus making the future maintenance cost much smaller and the proposed program even more financially attractive. It is always a good idea to use some probability of future failure since this is a much more realistic assumption.

In the next example, a boiler feedwater pump has a shaft failure after five years of operation. The plan is to replace the pump shaft every four years during the annual overhaul and thus avert a partial forced outage. In this example there is cost for lost production and the repairs are done on an emergency basis with overtime costs equal to twice the normal labor cost. In this example, a zero probability of failure is examined to show the effects on cost.

<table>
<thead>
<tr>
<th>Rotor Fails After 5 Years</th>
<th>Present Costs</th>
<th>Future Costs*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rotor Costs = $20,000</td>
<td>$30,000</td>
<td>$8,000</td>
</tr>
<tr>
<td>Labor Costs = $8,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pump Costs = $50,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lost Production Costs = $14,400</td>
<td></td>
<td>$24,000/4</td>
</tr>
<tr>
<td>Life = 20 yrs</td>
<td></td>
<td>$6,000/yr</td>
</tr>
</tbody>
</table>

\[
PM_p + P_p (CM_p) + A_p + E_p \quad < \quad PDM_t + P_t (CM_t) + P (A_t) + P (E_t)
\]

\[
0 + 0.20 (50,000) + 0 + \frac{100,000}{5} \quad < \quad 2,000 + 0.04 (50,000) + 0.2(0) + 0.2 \left(\frac{100,000}{5}\right)
\]

\[
10,000 + 20,000 \quad < \quad 2,000 + 2,000 + 0 + 4,000
\]

\[
= 30,000 \quad < \quad 8,000
\]
\[
\begin{align*}
CM_p &= $28,000/5 = $5,600/yr & CM_t &= 0 \\
A_p &= $14,400/5 = $2,880/yr & A_t &= 0 \\
E_p &= $50,000/20 = $2,500/yr & E_t &= $50,000/24 = $2,083/yr \\
Total &= $10,980/yr & Total &= $8,083/yr
\end{align*}
\]

* Replace rotor every 4 years: Labor = $4,000, pump lasts 4 more years.

The cost shown above assumes no failures for the life of the pump. Since one has already occurred, this is not a realistic assumption. Assuming that at least one failure would occur, the results are as follows:

<table>
<thead>
<tr>
<th>Present Costs</th>
<th>Future Costs*</th>
</tr>
</thead>
<tbody>
<tr>
<td>PM_p = 0</td>
<td>PDM_t = $24,000/4 = $6,000/yr</td>
</tr>
<tr>
<td>CM_p = $28,000/5 = $5,600/yr</td>
<td>CM_t = $28,000/24 = $1,167/yr</td>
</tr>
<tr>
<td>A_p = $14,400/5 = $2,880/yr</td>
<td>A_t = $14,400/24 = $600/yr</td>
</tr>
<tr>
<td>E_p = $50,000/20 = $2,500/yr</td>
<td>E_t = $50,000/24 = $2,083/yr</td>
</tr>
<tr>
<td>Total = $10,980/yr</td>
<td>Total = $9,850/yr</td>
</tr>
</tbody>
</table>

* Replace rotor every 4 years: Labor = $4,000, pump lasts 4 more years and one rotor failure occurs.

Using weighing factors and a zero probability of failure:

\[
P_p = \frac{1}{5} = .2 \quad P_t = 0 \quad P = \frac{0}{0} = 0
\]

\[
PM_p + P_p (CM_p) + A_p + E_p < > PDM_t + P_t (CM_t) + P (A_t) + P (E_t)
\]

\[
0 + .2(28,000) + 14,400 + 50,000 <> 24,000 + 0(28,000) + 0(14,400) + 0(50,000) \\
5 \quad 20 \quad 4 \quad 5 \quad 24
\]

\[
0 + 5,600 + 2,880 + 2,500 = 6,000 + 0 + 0 + 0 \\
$10,980 \quad $6,000
\]
This calculation doesn't provide the same result with zero probability of failure. It gives an unrealistic assessment of the maintenance cost. If we assume one failure, the probability factors will change as follows:

\[
P_I = \frac{1}{24} \quad P_p = \frac{1}{5} \quad P = \frac{1}{24} \times \frac{1}{5} = \frac{5}{24} = .21
\]

Substitution in the formula will then provide the following result:

\[
PDM_I + P_I (CM_I) + P_AI + P_EI = \frac{240}{4} + \frac{280}{2} + \frac{.21(1404)}{5} + \frac{.21(50)}{5} = 6,000 + 1,167 + 600 + 2,100 = 9,867
\]

In this case the cost difference between the two programs is $1,130/yr. This is not a significant difference and illustrates the fact that not all maintenance programs are cost justified. The above program made no attempt to determine the cause of failure and consequently did not develop any monitoring method to detect pending failure. The rotor was replaced every four years, thus saving the lost production cost and the overtime cost. However, the rotor replacement cost occurred every four years instead of every five years almost offsetting the savings.

1.2.7 Additional Benefits

To justify the development and implementation of a PDM program, you have to show how it will benefit your plant. The following are some of the additional benefits that can be obtained with a PDM program.

**Return on the Investment**

The chief advantage of PDM over other maintenance philosophies is that it saves money in maintenance and insurance costs as well as increased machine availability.
**Reduced Overtime**
Because you have anticipated when an equipment item will require maintenance, emergency repairs can be reduced. By the reduction of emergency repairs, you're able to make the repairs during the normal work period. One manufacturing company achieved a 30% reduction in overtime during the first year of its PDM program.

**Reduced Repair Costs**
By predicting when equipment will need maintenance, you can minimize the cost of parts. In this case, parts can be ordered in a routine fashion. In many cases, this will help avoid special handling charges, air freight charges and express overnight delivery charges often associated with unexpected or unplanned maintenance work.

**Reduced Unplanned Downtime**
Major generation interruptions can be avoided by the planning of outages at the most convenient and cost-effective times for your company. Those tasks requiring a unit outage can be coordinated and scheduled during periods of low electrical demand. These periods have traditionally been the Spring or Fall.

**Fewer Unnecessary Repairs**
Because PDM techniques include trending the condition of equipment, equipment is not taken out of service for inspection or maintenance unless it is needed. Therefore, you can keep equipment operating safely beyond normal traditional intervals often based on industry averages.

**Extended Machinery Life**
Well maintained equipment can be operated beyond normal design life. By extending equipment life, you can minimize expenditures for new equipment.

**Increased Plant Safety**
The most significant consideration for a PDM program is safety. The ability to detect malfunctions before they reach the catastrophic state protects equipment from releasing destructive energy when plant personnel are nearby.

**Controlled Insurance Costs**
The demonstration of a well-planned PDM program can make it possible to maintain or lower insurance expenditures for casualty, production, and capital equipment losses.
1.2.8 Additional Justification Recommendations

Several other recommendations for justifying a PDM program are as follows:

1. Focus on one or two areas of potential improvement that are major plant problems and show that predictive maintenance can solve these problems.

2. Review and examine your company goals. If the PDM program would help achieve a goal(s), prepare a case for consideration.

3. Identify regulatory requirements which can be satisfied through the benefits of a PDM program.

4. Identify which industry requirements can be satisfied through the implementation of a PDM program.

5. Begin collecting case histories (from your own plant and industry-wide) which illustrate the benefits of the implementation of a PDM program.

1.3 Setting Up an Organization

1.3.1 Introduction

Good people are one of the most important ingredients for a successful PDM program. Of almost equal importance is the organization of those people. In order for people to perform well, their work assignments must be made with care, and the organization must be designed to be both functional and efficient.

If a utility has more than one plant, and a PDM program will be implemented for each of these plants, then a decision must be made whether to:
Centralize the entire program, or

Have each plant implement an independent program

1.3.2 Centralized Program

A centralized program is one in which the program is essentially conducted out of one company location.

The same group of technicians travel at a determined time (weekly, monthly) to the various sites collecting data. The data is processed and analyzed back at headquarters and findings and recommendations are given to the various sites via reports, personal visits, and telephone calls.

These technicians serve as internal consultants, advising plant personnel on matters based on data analysis. If necessary, these technicians temporarily work at the plant in an advisory position.

Implementing a centralized PDM program has the following advantages:

- **Control** - The program can be administered at each location exactly as you desire.

- **Standardization** - The same monitoring equipment, data collection and analysis techniques, and reporting mechanisms at each location can be utilized.

- **Analysis Results** - Results from each site can easily be obtained for overall trending purposes and information exchange.

- **Monitoring Equipment** - Expenses can be minimized because the same equipment is used at all locations.
Shared Experience - Experiences gained at one site can be used at other sites. Sharing experiences can help to solve the same problem at other sites.

If centralization is the most appropriate organizational structure for the PDM program, here are several suggestions to make it an efficient, smooth-running operation:

- Standardize the program at all sites - If at all possible, require that each site:
  - Purchase the same monitoring equipment
  - Identify similar equipment to be monitored
  - Use the same format(s) for reports, records
  - Use the same vendors, whenever possible

- Purchase a van to be used by technicians - A good running, well-equipped van will aid efficiency and make life easier.

- Keep a supply of spare parts (cables, connectors, etc.) in the van for all pieces of equipment. An entire work day (including hours of travel) can be lost due to a faulty cable or a broken connector.

- Make monitoring equipment as portable as possible. Purchase lightweight, portable equipment when appropriate.

- Reports (analysis results; monthly, quarterly status reports, etc.) should be written in a standard format.

- Establish a communications network utilizing newsletters for the exchange of information.

- Conduct workshops several times per year to exchange ideas and solutions to common problems.
Involve other groups in problem solving. Utilize these groups and consultants for big or new jobs as a way to train team members on methods for future use.

1.3.3 Independent Program

The independent program structure is one in which each plant independently develops and implements its own program.

An independent program may exist because it is the only plant or type of plant in a utility, or in the case of a large utility, each plant can economically run its own program. In the latter case, headquarters personnel may oversee the programs of several plants and provide consulting services.

When implementing an independent program it can be customized to fit the existing needs and operation of the plant.

Implementing an independent program, with permanent on-site personnel has the following advantages:

- **Proximity** - Physical proximity of PDM people affects their efficiency and continuous access to equipment may be critical when a rapidly deteriorating condition has been identified.

- **Response** - Timely response to an emergency on critical equipment depends upon the close physical proximity of the program's personnel.

- **Exposure** - Frequent exposure to the equipment being monitored increases sensitivity to the equipment. A familiarity with a equipment's history both documented and undocumented is easily obtained and can be valuable in modifying the program.

- **Communications** - Constant, close physical proximity can have a major effect upon information communication between the PDM program and plant personnel.
Reliability - Reliable program results can be achieved through having the same people collecting, processing, and analyzing data on a routine basis. The actual organization of the people (engineers, technicians, operators, etc.) will depend upon the particular situation.

When developing and implementing an independent program within a utility having more than one PDM program consistency can be achieved by the following:

- Purchase similar monitoring equipment to that of other company programs.
- Use the same reporting forms as the other programs.
- Establish a communications network via newsletters, and visits for the exchange of information.
- Conduct workshops several times a year to exchange ideas and problem results.

1.4 Personnel Requirements

1.4.1 Introduction

The importance of effective people cannot be understated. Even with the latest hardware and software, the technology only works when it is properly applied. The program may be achieving all of its goals, but if the program people cannot relay the information in a tactful and helpful manner to the necessary parties, the program will not succeed.
In order to select the most effective people, two requirements/criteria must be established. The first is the most important individual personnel requirements for the PDM team members and the second is the duties of the team members.

1.4.2 Personnel Requirements/Criteria

When selecting team members, these requirements should be used for selection.

- Proper Attitude
- Background and Experience
- Leadership Ability
- Compatibility

*Proper Attitude*

Select people who have the desire to be a member of the team. They must be willing to dedicate themselves to the time and effort necessary to develop and implement the program. They must have the desire to obtain the required skills and knowledge in order to understand the theory, and to use the hardware and software.

They must be willing and able to be tireless supporters of the program. They must project a firm belief in the potential benefits of PDM. The team members must be aware that there may be initial negative reactions to the program.

*Background and Experience Requirements*

Table 1-1 gives general background and experience requirements for four typical skill levels
### Table 1-1 Background and Experience Levels

<table>
<thead>
<tr>
<th>SKILL LEVEL</th>
<th>BACKGROUND/EXPERIENCE</th>
</tr>
</thead>
</table>
| ENTRY       | - General familiarity with all types of plant machinery  
- General knowledge of machinery purposes and operation  
- Skill in identifying typical malfunctions  
- Ability to respond appropriately to typical malfunctions |
| INTERMEDIATE | All of the above plus:  
- General knowledge of machinery maintenance requirements  
- Skill in identifying typical malfunction indications |
| ADVANCED    | - Knowledge of general machinery overhaul principles  
- Familiarity with general maintenance requirements  
- Familiarity with maintenance procedures  
- Experience with typical machinery monitoring and diagnostics (M & D) programs  
- Experience with M & D hardware and software |
| SENIOR      | - Familiarity with machine design considerations  
- Knowledge of all aspects of machinery overhaul, repair, and maintenance  
- Knowledge of M & D theories (e.g. signal processing)  
- Ability to write M & D program performance reports  
- Experience in analyzing and correcting all types of machine malfunctions  
- Knowledge of all conventional M & D hardware and software  
- Familiarity with all conventional M & D techniques  
- Experience in advance analysis techniques |

**Leadership Ability**

One of the most important ingredients in the success of the program is the selection of a leader. Predictive maintenance programs often involve introducing new philosophies
and technologies into the plant. The ongoing findings and results of the PDM program often lead to significant changes in the way things are done.

The leader will have to serve as the program’s emissary. The leader must constantly and effectively sell the program to both management and plant personnel. The leader must be ready to motivate others to contribute to the program’s success. At times, the leader may be called upon to convince those affected by the findings of the program that the changes it will cause are beneficial. As the program grows, they must guide it through critical growth phases.

The leader of the PDM program must be a dedicated champion of the program and pursue the development and implementation of the program with such zeal and concentration that it becomes more of an obsession than a job. He will need to be involved in personnel issues: selecting, training, encouraging, and ensuring that his people are not snatched away from them prematurely! Strong leadership will have its rewards - the development and implementation of a strong program.

Compatibility

Compatibility addresses two requirements:

- Attitude
- Skills, Abilities

It is important to match individuals with job assignments that match their attitude and interests. If an individual’s interests do not lend itself to the tedious, sometimes uninteresting task of data collection, then the individual may have difficulty developing pride in their work and a sense of accomplishment from becoming an expert in this area. A person who is not interested in this work may take data inaccurately or incorrectly resulting in inaccurate analysis, processing, and the possibility of incorrect decisions.

If the individual’s work assignment is complementary, it helps to develop and maintain his knowledge of that work area. Your team members may possess the appropriate skills and knowledge through education/experience. Even if the individual assigned to
the task has the proper experience and expertise, they may still need some specific training. Personnel new to predictive maintenance and those with only the academic credentials, will need equipment-specific and methodology training.

1.4.3 Duties

Efficient use of manpower is critical for a PDM program. It is important to keep the team (and program) simple and streamlined. This may be difficult since PDM programs tend to affect many areas within the plant, and therefore involve many people.

The PDM program may use personnel from several departments. Listed below are typical positions in a program.

- Program Manager
- Technical Support
  - Engineer
  - Technician
- Maintenance*
  - Engineer
  - Supervisor (Mechanical)
  - Supervisor (Electrical)
- Instrumentation and Control Technician*
- Training Instructor*
- Operations Staff*

* Indirectly involved personnel
Tables 1-2 through 1-9 are listings of duties for those positions listed above. These duty listings will be of help when organizing the program, generating of position descriptions, and performing job and task analysis for formal training efforts.

<table>
<thead>
<tr>
<th>Table 1-2 Program Manager Duty Listing</th>
</tr>
</thead>
<tbody>
<tr>
<td>1-24</td>
</tr>
</tbody>
</table>
• Collect and analyze data in accordance with plant procedures
• Process collected data for validity
• Maintain trending data base
• Recommend need for corrective maintenance on monitored equipment
• Recommend changes in monitoring frequency
• Recommend configuration changes to monitored equipment
• Utilize electronic equipment, including computers
• Report to technical support group any time that standard operating conditions cannot be achieved
• Monitor and trend operating conditions of plant equipment
• Provide printouts of trends to Technical Support Group
• Provide PDM schedules to appropriate personnel
• Advise plant operating and maintenance personnel during equipment maintenance
• Assist with plant monitoring systems installation
• Assist in machinery balancing and alignment
• Report to technical support group, operations, and program manager any observed non-typical equipment behavior
• Report to technical support group and I&C any problem or malfunction with monitoring equipment
• Report to operations and program manager any plant equipment defect noted - whether or not the equipment is monitored by the PDM program

Table 1-3 Technical Support-Technician Duty Listing
- Review proposed equipment configuration changes
- Evaluate proposed equipment configuration changes
- Review and evaluate requests for changes to mandatory preventive maintenance commitments
- Review equipment and system technical documentation to evaluate causes of detected defects
- Recommend changes in equipment operating procedures/modes based on failure analysis

Table 1-4  Technical Support-Engineer Duty Listing

- Provide feedback to PDM program manager on the accuracy of the results of predictive maintenance diagnosis
- Provide recommendations to PDM manager concerning program
- Inform PDM program manager of preventive or corrective maintenance performed on monitored equipment
- Provide PDM manager with estimate of man hours and costs for preventive maintenance tasks proposed for substitution/augmentation by predictive maintenance
- Provide PDM program manager with predictive maintenance program indicators PM/CM ratio, scheduled/unscheduled maintenance ratios

Table 1-5  Maintenance-Engineer Duty Listing
- Provide engineering group assistance to analyze and implement program results.
- Provide feedback from corrective maintenance actions to improve PDM program.
- Implement changes required to improve the system and equipment environment.
- Provide support to training department in developing courses and instructional materials for PDM program members.

Table 1-6 Maintenance-Supervisor Duty Listing

- Calibrate equipment.
- Maintain calibration records on equipment.
- Calibrate installed plant equipment used for monitoring.
- Maintain all program equipment.
- Collect data for PDM program.
- Provide support to training department in developing courses and instructional materials for PDM program members.

Table 1-7 Instrumentation & Control (I&C) - Technician Duty Listing
Collect and maintain technical literature, training aids, and instructional information concerning the various predictive maintenance technologies.

Develop training courses and instructional materials for the PDM program.

Provide support to all departments in maintaining program quality and acquiring materials and technical information.

Schedule training for PDM program members.

Table 1-8 Training Instructor Duty Listing

Establish the standard operating conditions required for plant equipment monitoring.

Inform the Technical Support Group of any observed non-typical equipment behavior.

Report to the Program Manager any equipment on the monitoring program that has been taken out of service or has limited operation.

Work with the Technical Support Group to determine equipment critical to plant safety and reliability.

Develop data groups on plant process computer to support PDM program.

Provide support to the Training Department in developing training courses and materials.

Adjust operating procedures to optimize system and component performance.

Table 1-9 Operations Staff Duty Listing
1.4.4 Training Requirements

Once the program has been organized and the personnel staffing requirements have been defined, it is time to consider the issue of training. People need to be trained, but how much and in what areas? Consider conducting a needs analysis to identify personnel training requirements.

**Needs Analysis**

A needs analysis is a process that focuses on the major jobs (and personnel) for the purpose of identifying performance deficiencies, the cause of these deficiencies, and determining the appropriate solutions. A Needs Analysis is a five step process:

1. Identify the desired performance.
2. Identify the difference between expected and actual performance.
3. Identify the root cause of the deficiency.
4. Identify appropriate solution to correct the deficiency.
5. Select the appropriate solution to correct deficiency.

**Step 1 - Desired Performance**

Job duties have been determined and listed earlier. Job duties requiring the operation of data collecting and analysis equipment is easy to describe. However, at least some the members will require analytical knowledge, skills and abilities. Often team members will have the basic and advanced power plant experience, but they often lack the analytical knowledge of power plant theory and principles which are vital to analytical analysis of equipment problems. Specific electrical and mechanical knowledge may also be needed. Desired performance for these type of duties are hard to describe and may not be well defined at the outset of the program and may not
become known until the program is in operation. Training for PDM becomes an ongoing process as performance needs beyond the basics become known.

**Step 2 - Difference**

The PDM team may have extensive experience with power plant equipment, but have no skill in operating vibration monitoring equipment. One of the team members may possess basic machine design knowledge, but have no knowledge in identifying equipment faults. As many of these differences as possible should be documented and described. All these differences will usually not be immediately apparent.

**Step 3 - Cause**

At the start of the program, basic skills will be lacking and because the team members are new to their jobs and require basic training. Later, other deficiencies may become apparent.

Performance deficiencies of more mature teams usually fall into one of three areas:

- **Knowledge or Skill Factors** - PDM program personnel may not be able to do their job because they don't know how - they do not possess the required knowledge and skills.

- **Organizational Factors** - People may know how to perform their jobs, but they may not possess the proper tools, equipment, information or, they may depend on inputs from others which are missing or incorrect.

- **Motivational Factors** - Individuals may know the job, have everything they need to do the job well, but may have no incentive to do it, or to perform to the expected level.
Step 4 - Solution

Training will probably be the solution to most of the performance deficiencies if the team members have chosen correctly. Various types of training are available and will depend on the deficiencies that are observed. These will change with time and experience. However, do not neglect the possibility of other solutions.

Step 5 - Selection

After the appropriate solution has been identified and evaluated, one or more should be chosen and implemented. PDM requires a high degree of training not usually needed for most power plant work. It is similar to the training required for highly skilled personnel, such as engineers and I&C technicians. Training will also be ongoing since PDM is relatively new and is constantly changing as new techniques and knowledge become available. Training efforts should be formalized. A PDM training plan should be developed or training requirements should be integrated into the plant’s or department’s formal training plan.

Using the results of the needs analysis, a list of training requirements should be developed for each individual on the PDM program team. Training requirements are the difference between those skills and knowledge required to perform an assigned function and those which the individual presently possesses. Table 1-10 lists typical training requirements for PDM program personnel.

- Analytical skills
- Problem-solving techniques
- Diagnosis techniques
- Plant system theory
- Plant machinery theory (parts, operation, location)
Table 1-10 Training Requirements

Instructional Methods

An instructional method is a technique or strategy used to assist the trainee achieve mastery of a skill or knowledge. Various instructional methods can be used to assist the trainee. In the utility industry, these five methods are commonly used:

1. Lecture/Discussion

2. Demonstration/Practice

3. Self-Study

4. On-the-Job-Training

On-the-job training (OJT) is technically a training setting, though it is considered by many to be an instructional method.

The results of a small survey of utilities in U.S. indicated that these are the most commonly used instructional methods for training PDM personnel:

> In-House Training
- On-the-Job-Training
- Equipment Vendor Training
- Vendor/Consultant Training

Table 1-11 presents instructional methods and examples of activities which may be appropriate for your use.

<table>
<thead>
<tr>
<th>METHOD</th>
<th>EXAMPLES</th>
</tr>
</thead>
</table>
| LECTURE/DISCUSSION              | School  
Seminar  
In-house training program  
On-the-job training  
University  
Equipment Supplier  
Consultant  
Institute (e.g. Vibration Institute)  
School (e.g. machinery, vibration)  
Commercial Training Supplier |
| SELF-STUDY                      | Equipment Supplier  
University  
Consultant  
School |
| DEMONSTRATION/PRACTICE          | Consultant  
Institute (e.g. Vibration Institute)  
School (e.g. machinery, vibration)  
Commercial Training Supplier |
| ON-THE-JOB-TRAINING             | In-house training program  
Equipment Supplier  
Consultant  
Commercial Training Supplier |

Table 1-11 Instruction Methods/Examples

*Instructional Media*

Media is a means used to transmit information to the trainee. In the utility industry, the most commonly used types of media are:
Results from the same survey indicate that these are the most commonly used media in training PDM personnel:

- Manual (Equipment Supplier)
- Slides
- Illustrations/Drawings
- Transparencies
- Charts/Graphs/Diagrams
- Textbook
In-House Training

Many plants have discovered that one of the most effective ways to train personnel is through the development of an in-house training program. There are several benefits to the development and implementation of such a program:

- Designed specifically to meet the needs of your personnel
- Can be presented on an as needed basis
- Changes and revisions to the program can be easily made when necessary

In order to develop an effective in-house training program, consider the following practices:

- Emphasize basic monitoring and diagnostic fundamentals
- Dedicate a majority of time to hands-on training-practice using the actual equipment
- Include as many case histories as possible in the program
- Formalize OJT
- Include visits to other utilities to survey other PDM programs
- Use outside speakers (vendors, universities, schools)
- Cross train by varying duties/assignments

1.5 Budgeting Considerations

1.5.1 Introduction

It can take three to five years to get a good PDM program established. Remember however, that since the technology continually changes, program development is never completed. The first year of program development and implementation requires a heavy investment in new equipment and personnel training - about 60% of the budget. After about two years, a large part of the budget will be needed for equipment replacement and upgrading. But funds should also be budgeted to purchase new equipment to expand the capabilities of the predictive maintenance group as well as to take advantage of new technology. For new and replacement equipment, 50% of the
budget may continually be needed. Replacement costs estimates should be based on a life expectancy of five years for electronic equipment.

1.5.2 Budget Estimation Plan

The following is a plan designed to help develop an initial budget estimate.

1. Determine initial equipment costs:
   - Installed Instrumentation
   - Monitoring Instrumentation
   - Analysis & Diagnostic Instrumentation

2. Determine Replacement Equipment Costs (optional at this time)

3. Determine Personnel Costs

4. Determine Personnel Training Costs

5. Determine Instrumentation Expenses (Calibration and Maintenance)

6. Determine Miscellaneous Costs

7. Determine Transportation Costs (centralized organization)

Step 1 - Initial Equipment Costs

The initial purchase of new equipment will require almost 60% of your budget. The equipment problems that you expect to address in your PDM program determine the level and type of monitoring required, which in turn, determine the pieces of necessary equipment. If this is appropriate, consider installed (permanent) instrumentation costs in two ways:

- Cost of the Material Itself
- Initial Installation Charges

Typical installation charge estimates are 2-3 times the price of the material. Since this equipment is usually more costly than monitoring instrumentation, it may be possible to share the cost with another function in your plant that could also use this equipment.
**Step 2 - Replacement Equipment Costs/Upgrading (Optional)**

While normal replacement costs should be based on a life of eight years for electronic equipment, improvements in the technology occur so quickly that it can be economically justifiable to update some equipment because of the resulting labor savings and increased analysis capability.

If applicable to the program, budget to replace 20% of sensors and probes every year. Five years of usage is a good estimate of permanently installed instrumentation (e.g., transducers, signal conditioning equipment). Estimate 5-10 years for portable instrumentation, if regularly calibrated and maintained. For analysis and diagnostic equipment, estimate 5-10 years of life, but only 3-5 years before it is significantly outdated. Enter the replacement equipment/upgrading costs (optional).

**Step 3 - Personnel Costs**

Personnel costs include those individuals who will charge direct labor to the program. Don’t forget to include any overhead costs to their labor rates. Include in your estimate any indirect costs: training, sick leave, and vacation time. Any support help (typing, filing etc.) should also be included. Management and supervision costs may also be applicable. 10% of direct labor is a good estimating factor.

**Step 4 - Training Cost**

Training is an ongoing effort. Begin with training courses offered by instrumentation and equipment manufacturers. Industry-oriented seminars, meetings, and symposia can then be used as continuing training for personnel. In addition to training conducted off-site (or on-site by a vendor), training via videotape, computer, sound/slide, and self-paced text should be considered as alternatives. Travel, living expenses, and tuition are considered direct costs. Labor costs for these activities are considered indirect costs.

**Step 5 - Instrumentation Expenses**

Include instrument maintenance and calibration costs (estimate 10% of initial costs per year). Repair services should also be budgeted. A typical estimate factor is 10% of the initial cost per year. If the PDM program includes permanently installed instrumentation, a special repair cost may be necessary because damage occurred, for example, during equipment overhaul. An estimate of 5% - 50% for installed instrumentation which may be damaged and require repair or replacement is a good factor.
Step 6 - Miscellaneous

The budget should include certain other miscellaneous expenses. These include:

- Small Equipment/Tools
- Computer Diskettes
- Log Sheets/Paper
- Cases
- Cables
- Cables
- Connectors

Step 7 - Transportation Costs

If the program is to be centralized (a utility with several plants), a van or trailer equipped with (diagnostic) equipment may be needed. The vehicle plus operating and maintenance costs should be budgeted.

Total Costs

List the total cost from all categories. The grand total figure is the initial budget estimate for the program.

1.6 Success Factors

1.6.1 Introduction

Once the PDM program has been organized, personnel requirements addressed, training requirements identified, budget requests funded, and appropriate techniques and equipment chosen, the PDM program is ready for implementation. Implementation is not complete without documenting the success and progress of your program. In fact, it can be said that documentation is one of the most important components of a
successful PDM program. The following approaches are presented as an aid to help avoid problems during the implementation phase.

1.6.2 Success Factors

**Success Factor 1: Start Small**

This is the key to successfully implementing a PDM program. In the beginning, identify a block of equipment where you'll likely to see appreciable results. Don't try to solve all the problems at once. Starting small has three main advantages. It enables you to:

- Build support and confidence for the program among plant maintenance and production personnel as well as management.
- Redefine and refine the program in small segments—small problems are easier to solve than big ones.
- Achieve the program's initial expected results.

**Success Factor 2: Begin with Problem Equipment**

It is a good idea to incorporate problem equipment and critical equipment into the program first. These are the machines that need attention, experience frequent mechanical problems, or equipment that reduces or stops electrical production when they fail. When the results of the program show that the implemented methodologies work, credibility is established. Solving a present problem and helping plant personnel reduce failure are excellent ways to build up support for a new program.

**Success Factor 3: Generate Early Results**

It is crucial in the first three to six months of the program to generate early results without making any major mistakes. Unfortunately, any major miscalls in the program during the early phases can substantially erode plant and management support.

In the beginning, it is a tendency of eager and sometimes inexperienced PDM program personnel to become misdiagnose problems. They collect some questionable readings and recommend that the equipment be shut down immediately, only to find that their
recommendation was a bad one. Unfortunately, one bad recommendation can wipe out one hundred good ones.

Move quickly enough with the PDM program to show some immediate benefits, yet slowly enough to avoid any early mistakes.

**Success Factor 4: Build Program Awareness**

A common problem in the implementation of a PDM program is that plant personnel often lack a general knowledge or awareness of the program. Without plant support (especially the operations department), the early progress of the program may become impeded.

**Success Factor 5: Be Ready to Overcome Program Resistance**

Like any new program, the predictive program may meet with some resistance. Change threatens some individuals, the new technology used by the program may initially intimidate others. There will be those who will believe in the methodologies, techniques and their benefits, and those who will have trouble with it. Communication is the principal tool in overcoming these difficulties. A positive program awareness is essential in combating and overcoming program resistance.

**Success Factor 6: Have an Implementation Plan**

A formal plan to implement the predictive program is needed. An implementation plan is as important to the successful implementation of a predictive program as blueprints are to the successful building of a home. The plan provides a look of organization. It shows that the predictive approaches are thoroughly investigated, defined, and fully justified. A formal implementation plan is also an excellent communication tool to ensure that personnel involved in the program are aware of its full scope and their roles. Lastly, an implementation plan is an effective way to ensure that as few mistakes as possible occur during the critical first stages.

**Success Factor 7: Avoid Weakening the Program**

A problem that may occur during implementation is the program’s efforts may become weakened by more immediate emergencies. In any work situation, there is always a steady supply of problems that demand immediate attention. It is the tendency of management to direct personnel to postpone less immediate tasks (e.g., monitoring) to address these emergencies. If care is not exercised, the monitoring and
diagnostic program efforts can become so weakened that initial momentum falters and effectiveness is diminished.

**Success Factor 8: Keep Consistent Personnel**

It is highly desirable during implementation to keep the same personnel in the program. It is especially important that the same personnel collect data. Consistency in personnel helps to ensure accurate and consistent data collection and analysis, plus it presents a unified, stable organization.

**Success Factor 9: Enlist Strong Management Support**

The implementation of a predictive program requires the strong support of management. This support must go beyond the initial funding. The success of the program should be incorporated as a company goal so that crucial cooperation can be gained from many areas of your organization.

**Success Factor 10: Reward Successful Results**

Successful results should be rewarded in some tangible fashion. Caps, shirts, jackets, plaques, and certificates have all been used at times to visibly reward participants in a successful Predictive Maintenance program. The awards are usually handed out at some annual function at which the last year's results are recognized. The reward acknowledges the importance of each individual and group to the success of the program, publicizes the program and builds support for the program.

1.6.3 Program Documentation

In a realistic sense, the most important program documentation is the monetary savings from each corrected problem. Without this documentation, the justification of the program's budget, and any desired expansion could be impaired.

An awareness of the program must be initiated and maintained in order to ensure continuance and growth of the program. Reporting and documentation are valuable forms of communication. Program success reporting should be presented to production, operations, maintenance, and management personnel at regularly scheduled time periods (see Table 1-12). These reports help build confidence and support for the programs. They also enable personnel involved to see the results of their work, and for management to begin to see the return on their investment in the PDM program.
M = Monthly, AN = As Needed, Q = Quarterly, Y = Yearly

Table 1-12 Recommended Reports and Frequencies

<table>
<thead>
<tr>
<th></th>
<th>News</th>
<th>Statistics</th>
<th>Repairs</th>
<th>Costs</th>
<th>Exceptions</th>
<th>Evaluation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operators</td>
<td>M,Q</td>
<td></td>
<td>AN</td>
<td></td>
<td>M,AN</td>
<td>M</td>
</tr>
<tr>
<td>Plant Manager</td>
<td>M,Q</td>
<td>M</td>
<td></td>
<td>Y</td>
<td>M,AN</td>
<td>M</td>
</tr>
<tr>
<td>Maintenance Managers</td>
<td>M,Q</td>
<td>M</td>
<td>AN</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Planner</td>
<td>M,Q</td>
<td>M</td>
<td></td>
<td></td>
<td></td>
<td>M</td>
</tr>
<tr>
<td>Shift Engineer</td>
<td>M,Q</td>
<td>M</td>
<td>AN</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maintenance Engineers</td>
<td>M,Q</td>
<td>M</td>
<td>AN</td>
<td></td>
<td>M,AN</td>
<td></td>
</tr>
<tr>
<td>Plant Engineer</td>
<td>M,Q</td>
<td></td>
<td>AN</td>
<td></td>
<td>M,AN</td>
<td></td>
</tr>
</tbody>
</table>

News - General program information, case histories, recent results and summaries of repairs, problems solved, items of general interest.

Statistics - Number of machines monitored, number of problems discovered.

Repairs - Information describing repairs that were made.

Costs - Yearly costs, benefits, total program costs, equipment costs, labor cost.

Exceptions - Information about machines that are showing problems, action taken.

Evaluation - Assessment of equipment problems, recommended and completed actions
Chapter 2

PREDICTIVE MAINTENANCE PROGRAM IMPLEMENTATION

2.1 Program Implementation Overview

This section describes the fundamental steps involved in implementing and operating a predictive maintenance program. The PDM program steps discussed in this section include:

- Plant Equipment Selection
- Task Selection
- Monitoring and Diagnostic Equipment Selection
- Task Frequency Selection
- PM Procedures and Training
- Taking Data
- Trend Analysis
- Diagnostic Analysis

*Plant Equipment Selection*

Since all the equipment in the power plant cannot be included in a predictive maintenance program, critical equipment that will provide program justification must be selected for monitoring. Several categories of equipment are presented and prioritization techniques are discussed. Several techniques to identify critical equipment are presented along with ideas on how to gather data needed to make this determination.
**Task Selection**

Equipment task selections are key elements that have a major impact on overall program effectiveness. The previous section identified the sources of information and techniques useful in selecting the equipment and tasks to be included in the PDM program. Selection should be based on safety or reliability consequences as well as equipment failure history.

**Monitoring and Diagnostic Equipment Selection**

The specification and purchase of monitoring and diagnostic equipment will be a major decision. This decision will depend on budget constraints, available technology, level of personnel expertise and training, and scope of the program. These will all be discussed and several ideas presented.

**Task Frequency Determination**

Frequency determination takes into account experience, failure history, failure probability, and economic analysis. The output of the frequency determination is a list of frequencies designed to increase plant availability and minimize costs. In addition, other practical considerations should be taken into account when assigning task frequencies. These include:

- Assigning frequencies compatible with other closely related equipment.
- Reviewing and adjusting frequencies as indicated by observation, history records, experience, regulations, engineering analysis, and equipment supplier recommendations.

**PM Procedures and Training**

Procedures for a predictive maintenance program are key to the overall success of the PDM program. They ensure that monitoring and diagnostic tasks are carried out consistently and correctly each time, ensuring data integrity. Training goes along with procedures and ensures that the personnel selected to carry out the program have the necessary skills and knowledge to perform their work correctly.
**Taking Data**

Data is the heart of the predictive maintenance program. Manual collection of data is the traditional method, but the proliferation of the computer and computer-based monitoring equipment has revolutionized data taking and data reduction. It is now possible to collect and store large amounts of data economically. Computer systems have also simplified the retrieval and use of data to more effectively predict equipment degradation.

**Trend Analysis**

Trend analysis puts the data in a form that allows it to be quickly and easily analyzed. In addition, the trends are compared to limits that are key to decision making. Trends are also used to establish monitoring frequencies and to change these frequencies based on the indicated trends.

**Diagnostic Analysis**

Diagnostics is the art of using data to determine equipment problem causes. Root cause analysis, range analysis, and analytical troubleshooting are diagnostic techniques that help determine the cause of equipment degradation and failure. Effective diagnostic analysis leads to refinements in monitoring techniques that allow even more accurate and effective predictive maintenance results.

The following sections will cover each of these topics in more detail along with ideas and tips on how to implement and use these techniques to successfully implement and operate an effective predictive maintenance program.

### 2.2 Plant Equipment Selection

#### 2.2.1 Introduction

One initial task of establishing an effective PDM program is the identification of equipment items that are candidates for predictive maintenance monitoring. The specific objective is to create ranked lists of equipment that are candidates for PDM using measurable criteria. Recognizing that a large power plant has thousands of items of equipment items, performance of this identification task requires methods
that permit quick, approximate, but conservative identification of significant equipment.

2.2.2 Method

The following is one approach for identifying equipment as well as a method for classifying and prioritizing equipment.

Data Review
The first task is gathering plant and industry data. Data is needed to establish classifications. Some typical sources of data are as follows:

- Technical Specifications - Identifies equipment that could cause a limiting condition for operation.
  
- Equipment Event Reports - Identifies equipment that has failed or caused problems in the past.
  
- Outage Data - Identifies equipment that is critical to plant availability and that has caused complete or partial outages in the past.
  
- Plant Piping and Instrumentation Diagrams (P&IDs) - Identifies equipment that:
  
  - could cause a reduction in power generation
  
  - could present a safety hazard
  
  - would endanger the above equipment should it fail
  
  - is considered significant equipment

- Equipment Performance Histories - Identifies equipment critical to plant safety and reliability.
System Description - Identifies equipment critical to plant safety Manuals and reliability.

Plant Staff - Identifies equipment that should be identified based on plant staff opinion.

Classification Systems

A classification system to identify all equipment critical to plant operation must be established. The designations for classification vary from plant to plant. Most systems have at least three categories: critical, essential and other. Some examples of these classification systems are shown in Tables 2-1 through 2-3.

<table>
<thead>
<tr>
<th>CLASSIFICATION</th>
<th>CRITERIA</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRITICAL</td>
<td>Absolutely necessary for continued plant operation and generally cannot be spared</td>
</tr>
<tr>
<td>ESSENTIAL</td>
<td>Necessary for at least partial plant operation, but could be spared or possible partially spared</td>
</tr>
<tr>
<td>GENERAL</td>
<td>Nonessential to the major plant process OR, if essential, is a backup to the essential equipment.</td>
</tr>
</tbody>
</table>

Table 2-1 System 1

<table>
<thead>
<tr>
<th>CLASS</th>
<th>CLASSIFICATION</th>
<th>CRITERIA</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>CRITICAL</td>
<td>Failure would result in major power reduction</td>
</tr>
<tr>
<td>2</td>
<td>NECESSARY</td>
<td>Failure would result in power reduction</td>
</tr>
<tr>
<td>3</td>
<td>AUXILIARY</td>
<td>Failure would result in no power reduction, but is still needed for reliable operation</td>
</tr>
<tr>
<td>4</td>
<td>OTHER</td>
<td>Any other machinery</td>
</tr>
</tbody>
</table>

Table 2-2 System 2
<table>
<thead>
<tr>
<th>CLASSIFICATION</th>
<th>CLASS</th>
<th>CRITERIA</th>
<th>EXAMPLE</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRITICAL</td>
<td>NO SPARE</td>
<td>Essential machine; loss would result in total or partial loss of generation for an extended period of time</td>
<td>Turbine generators</td>
</tr>
<tr>
<td>CRITICAL</td>
<td>SPARE</td>
<td>Failure or shutdown would result in partial loss of generation.</td>
<td>ID, FD fans</td>
</tr>
<tr>
<td>NON-CRITICAL</td>
<td></td>
<td>Failure or shutdown will not immediately affect generation.</td>
<td>Chemical pumps, ventilation fans</td>
</tr>
<tr>
<td>PROBLEM</td>
<td></td>
<td>Machinery that requires maintenance or has a history of a recurring problems</td>
<td>Varies</td>
</tr>
</tbody>
</table>

Table 2-3 System 3

*Criticality List*

Once the classification system has been established, a listing of all equipment identified as "critical" can be made. Using your classification system, listings for the remaining classifications/classes can be made. Equipment considered candidates for PDM activities can be grouped according to three critical items lists (CIL):

- Mandatory Maintenance List (MML)
- Failed Equipment Critical Items List (FCIL)
- Other Key Equipment Critical Items List (KCIL)
The first CIL is a list of equipment associated with mandatory maintenance actions. This mandatory maintenance list (MML) includes equipment and tasks required by insurance, operating license, vendor warranty, government regulations, technical specifications, environmental qualification requirements, and related documents. Development of this list of equipment and PM tasks is straightforward it can be derived from a detailed review of documentation that identifies mandatory maintenance actions.

The second list is a failed equipment critical items list (FCIL) based on an analysis of equipment that has experienced failures and caused a loss of plant availability and/or high corrective maintenance costs. Ranking of equipment in this list is based on the experienced annual cost of these equipment failure consequences. For example, several failures of motor operated valves resulted from causes such as loose electrical connections, broken wires, inadequate stem/gearbox lubrication, or dirty contacts. The PM tasks suggested by this failure history are regular periodic inspections or operational testing.

The third critical items list, key equipment critical items list (KCIL), is comprised of other key equipment which has not yet experienced failures, but, based on functional importance could be expected to result in a significant maintenance cost over plant life. Equipment on this list is ranked on the basis of potential annual maintenance cost.

Prioritization

Using the listing of critical equipment, place them in order by ranking to produce a prioritized listing of critical equipment. In most ranking systems approximately twenty percent of the equipment will show up as critical or as causing the most lost generation. This statistical result is predicted by Paretto's Law or the 80-20 rule.

2.3 Task Selection

2.3.1 Introduction

This process will result in a series of tasks that require equipment performance monitoring to detect any function degradation associated with components. Effective and applicable tasks are performed to reduce the possibility of a functional failure. These tasks are defined as follows:
> **Effective Task** - risk is reduced by task performance to an acceptable level. The task is cost-effective.

> **Applicable Task** - the task has the desired effect (really prevents functional failure).

Table 2-4 is an example of the results of this type of analysis for a circulating water pump.

The PDM tasks identified for this example are those shown in the "Effective and Applicable PDMs" column of Table 2-4 that involves performance monitoring, including:

- Vibration Analysis
- Thermographics
- Acoustics
- Trending (Flow/Discharge)

If this example is followed for all of the equipment and tasks identified during analysis, the PDM program will include all of the tasks for which monitoring is performed to:

- Detect Performance Degradation
- Isolate Faults
- Predict Maintenance Requirements
- Indicate Deviations from a normal Operating Profile
2.3.2 Determine Predictive Method

Performance monitoring is the essential action required by the PDM. Performance monitoring provides a means of evaluating equipment performance by comparing a present indication to a standard or some previous value. Traditional testing techniques are used to indicate normal changes in equipment performance. Many more techniques have been developed to detect equipment component problems. These techniques are needed to determine component deterioration and potential
failure and allow maintenance or replacement to be scheduled in advance of failure. Several of these techniques are discussed in detail in the following chapter and include the following:

- Thermography/Infrared Thermal Inspection
- Vibration Monitoring
- Acoustic Emissions
- Trending of Operational Parameters
- Insulation Resistance Monitoring
- Fluid Monitoring
- Fiber Optics
- Nondestructive Examination

Regardless of the techniques in use, effective performance monitoring programs will have the following characteristics:

- Tests are Performed under Standard Conditions
- Data is Collected and Recorded to Track Equipment Performance Over Time
- Repairs are Performed in Anticipation of a Failure

Performance monitoring offers two advantages over traditional scheduled maintenance policies where equipment is removed from service and disassembled at a fixed time interval. First, performance monitoring techniques are used while equipment is on-line. This offers distinct advantages since critical components can be evaluated without a plant outage. A second advantage is the low relative cost of a performance monitoring program. The cost of equipment disassembly, re-assembly and lost generation can be significant. Performance monitoring requires only the initial purchase of a measuring device and the time necessary to take, record, and evaluate readings.

Selection of the predictive method to use and its frequency should be based on its capability for predicting degradation of the equipment component identifies. Data should be able to be plotted and analyzed (i.e., trended and diagnosed) to determine if problems exist. When a potential function degradation or failure is determined,
maintenance personnel should determine the root cause and plan corrective maintenance or replacement.

A brief discussion of each of the PDM techniques follows. More detailed explanations are included in the following chapter of this text.

**Thermography/Infrared Thermal Inspection**

This is a nondestructive, noncontact testing method to identify potential failures over a period of time. Thermography is used effectively to monitor electrical equipment such as breakers, cable splices, and insulation. It can also be used to spot potential or the early stages of a failure in any equipment where heat or the absence of heat is an indication of potential or actual failure, such as drain valves, steam traps, and insulation. A device providing a direct value (i.e., does not require interpretation) is preferable. When using thermography in a PDM program, it is important to monitor the same location at the same conditions each time the task is performed. Applications include:

- Breakers and Other Switch Gear
- Cable Splices and Connections
- Bearings
- Heat Exchangers (Broken Baffles, Hot Spots, etc.)
- Insulation (Degradation, Failure)
- Electric Motors (Overheating, Cleanliness, etc.)
- Steam Trap Operation

**Vibration Monitoring**

The pattern of vibration, or its signature represents the current mechanical condition of the component. Equipment condition will change due to wear, stress, and misalignment. These changes in condition will affect the vibration signature. Trending of this signature can indicate potential failures such as:

- Bearing Degradation
- Shaft Misalignment
Bent/Bowed Shaft
Unbalance

Vibration analysis is effective for:

- Periodic Routine Checks of Mechanical Condition
- Troubleshooting Problems
- Checking Equipment Prior to Planned Maintenance (Overhaul)
- Repair or Post-Overhaul Checks to Be Certain that Equipment has been Returned to Good Operating Condition

An effective vibration monitoring program combines both periodic and continuous monitoring. Most rotating equipment should be included in this program except where functional characteristics or service justify exclusion. Key program elements are:

- Baseline Data Collection and Retention for Comparison with Past and Future Readings
- Readings Made at Each Bearing
- Consistent Measurement Points and System Conditions
- Vibration Limits Requiring Action are Specified in Advance
- Inspection Records
- Data Collected on a Fixed Schedule

**Acoustic Emissions**
Acoustic emission monitoring focuses on sounds resulting from processes, such as fluid leakage through a valve or crack initiation in a vessel or piping wall. A transducer detects sound energy generated in the material being monitored and converts them to an electrical signal.
Applications in a PDM program include:

- Leak Detection (Water/Steam Valves)
- Pressure Vessel and Piping Monitoring

**Trending of Operational Parameters**

Temperature, pressure, flow data and calculated parameters such as efficiency, are plotted and used as a diagnostic tool for evaluating equipment condition and predicting the rate of degradation. The relationships of trended parameters and the establishment of patterns allow the maintenance engineer to make predictions of maintenance needs.

Examples of operational data to be trended for a pump are as follows:

- Suction Pressure
- Discharge Pressure
- Pump Efficiency
- Filter Differential Pressure
- Motor Run Current
- Flow Rate
- Bearing Temperature

**Insulation Resistance Monitoring**

The electrical resistance between two conductors separated by an insulating material is measured. These resistance measurements will be affected by factors such as surface conditions, moisture, temperature, magnitude of test potential, duration of application of test, and residual charge in the winding. Insulation resistance history of a given machine is a useful way to detect insulation degradation.

**Fluids Monitoring**

The monitoring of lubricants, coolants, and process fluids for both physical and chemical properties has increased the reliability of many systems and components in a variety of industries. Typical applications for diagnostic monitoring of fluids are:
Lubricating oil analysis programs represent the most commonly used methods of diagnostic monitoring of fluids. The analysis program can support and document:

- Lube Oil Change Frequency
- Bearing Wear Indication
- Component Wear Indicator
- Cooling Coil Leaks

The success of a good oil analysis program is determined by the maintenance department's commitment to the oil analysis program, the proper selection of the equipment, and effective testing intervals.

**Fiber Optics**

Fiber optics are used for visual inspection of normally inaccessible areas and is one of the few techniques that requires that equipment be taken out of service. When used with other PDM techniques, such as performance diagnostics, fiber optics can verify suspected problems thereby saving time by not having to fully open the equipment. Applications include interior inspections of:

- Heat Exchangers
- Steam Generators
- Pumps
- Turbines

**Nondestructive Examination (NDE)**

Non-destructive examination techniques are used to determine material condition and how stress and wear affects the material. When the extent of material degradation is known, unexpected failures can be prevented by maintenance. The type of test used depends on material type, size, thickness, and geometry and include surface and subsurface tests.
Applications include:

- Eddy Current Tests for Heat Exchanger Tubes Thickness
- Ultrasonic Tests for Heat Exchanger Tubes, Turbine Generator Rotors, and Piping

**Replication**

Replication is a nondestructive metallographic examination that can identify creep microcracks which could lead to fracture failures. The replication test provides assurance of safe operation for the useful life of a component and prevents the unnecessary retirement of plant components.

### 2.4 Monitoring and Diagnostic Equipment Selection

#### 2.4.1 Introduction

When planning a predictive maintenance program, it is important to first decide which predictive technique(s) will be used in the program. Based upon this decision, research can be conducted to determine which of the equipment and instruments available from various vendors meet the needs of the program.

#### 2.4.2 Decision Tools

In order to determine which predictive techniques to use in the program the following information should be reviewed:

- Program Philosophy
- Program Justification (Specifically the Results of the Cost Benefit Analysis)
- Program Goals
- The Extent of Management Commitment (Monetarily and Manpower)
Based this review, a rational decision to satisfy the needs of the program should be possible.

Table 2-5 is a listing of the major predictive techniques/methods. For each of these, the following information is given:

- **Purpose** - Goals
- **Application** - Examples of Best System, Equipment, or Components
- **Equipment** - Listing of Equipment Required to Perform Method/Technique
- **Operator Training** - Description of Training Required for On-site Personnel to Perform Method/Techniques
- **In-house vs. Contractor** - Pros and Cons of In-house vs. Contractor (Off-site) Performance of Method/Techniques

### 2.4.3 Other Options

In some cases, such as a small pilot program, it may be better to rent or lease the equipment or hire a vendor or consultant to conduct the program for the first year. This avoids many of the costs of setting up a complete program and avoids the capital cost of purchasing the needed equipment. Some of the advantages and disadvantages are as follows:

**Advantages**

- No Capital Cost
- Flexibility to Try Out Different Types and Manufacturer's Equipment
➤ Avoid Purchasing Rapidly Obsolescent Equipment
➤ Avoid Training Cost (If Using a Contractor)
➤ Avoid the Risk of Being Tied to a Program That is Not Effective
➤ Gain Program Experience at Minimal Cost

Disadvantages

➤ Higher Operating Cost
➤ Inability to Easily Expand the Program
➤ Inability to Easily Respond to Immediate Equipment Problems
➤ Loss of OJT for Maintenance Staff (If Using a Contractor)
Table 2-5 Predictive Techniques/Methods

<table>
<thead>
<tr>
<th>Method/Technique</th>
<th>Purpose</th>
<th>Application</th>
<th>Equipment</th>
<th>Operator Training</th>
<th>In House vs. Contractor</th>
</tr>
</thead>
</table>
| Vibration Analysis    | Ranges from measuring displacement to measuring forces applied on a piece of equipment  
|                       | Ranges from measuring specific frequencies of forces which relate to specific internal conditions  
|                       | Trend equipment characteristics  
|                       | Early detection of impending equipment failure                         | Rotating machines  
|                       | Turbines  
|                       | Generators  
|                       | Pumps  
|                       | Fans  
|                       | All major auxiliary equipment  
|                       | Piping                                                                  | Hand-held portable unfiltered velocity meter  
|                       | Bearing checking meter                                                 | Balance analyzer  
|                       | Spectrum analyzer with probes and accessories                           | Modal testing kit  
|                       | Sensors: accelerometers, velocity, proximity, pressure               | Time-based instruments (oscillographs, etc.)  
|                       | Desk-top computer (trending, multi-case alignment, calculations)      | Data collection is 90% OJT  
|                       |                                                                        | Analysis requires several weeks of training per person                  |                                                 | Very few contractors provide service  
|                       |                                                                        | Detailed analysis requires intimate knowledge of system operating procedures, component internal construction, history |
| Oil Analysis Spectrometry | Determine condition of lub oil to help predict mechanical problems and failures  
|                        | Estimate wear rates                                                    | All systems.              | Equipment for filtration membrane  
|                        |                                                                        | Microscope               | Kit for water determination  
|                        |                                                                        | Must know functional properties of analyzer  
|                        |                                                                        | Must know oil specifications  
|                        |                                                                        | Must know "normal" wear product and contamination levels for classes of equipment  
|                        |                                                                        | Very detailed, must know functional properties of analyzer  
|                        |                                                                        | Analysis requires several weeks of training per person                  |                                                 | Average turnaround time for samples analyzed off-site is 10 days  
|                        |                                                                        | Separate lab would have to built on-site.  
|                        |                                                                        | Other labs have backup equipment in case spectrometer fails  
|                        |                                                                        | Off-site analysts see samples from many other plants - can identify industry-wide problems  
| Macrocontamination Fuel | Detect excessive fuel in liquid-fuel reciprocating equipment           | Liquid fuel               | Superheater  
|                        |                                                                        | Detector                | Strip-chart recorder  
|                        |                                                                        | 95% OJT in lab techniques  
|                        |                                                                        | For routine trending analysis on-site vs. offsite factors are about equal  
|                        |                                                                        | For urgent sample analysis, off-site service is not fast enough  

2-18
<table>
<thead>
<tr>
<th>Method/Techique</th>
<th>Purpose</th>
<th>Application</th>
<th>Equipment</th>
<th>Operator Training</th>
<th>In House vs. Contractor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solids</td>
<td>Presence of solids tells a number of occurrences in system</td>
<td>All systems</td>
<td>Non-polar solvent</td>
<td>95% OJT in lab techniques</td>
<td>For routine trending analysis: on-site vs. off-site factors are about equal&lt;br&gt;For urgent sample analysis, off-site service is not fast enough</td>
</tr>
<tr>
<td>Water</td>
<td>Discloses violation of less than 500 parts per million</td>
<td>All systems except water-based or water-added systems</td>
<td>HN plate</td>
<td>95% OJT in lab techniques</td>
<td>For &quot;routine&quot; trending analysis: on-site vs. off-site factors are about equal&lt;br&gt;For urgent sample analysis, off-site service is not fast enough</td>
</tr>
<tr>
<td>Physical Testing</td>
<td>Estimate fluid film strength</td>
<td>All systems</td>
<td>Capillary</td>
<td>95% OJT in lab techniques</td>
<td>On-site capability convenient but not mandatory&lt;br&gt;Tests require only small amount of investment in lab equipment</td>
</tr>
<tr>
<td>Viscosity</td>
<td>Determine system instability</td>
<td>All systems</td>
<td>Infrared energy radiation equipment</td>
<td>95% OJT in lab techniques</td>
<td></td>
</tr>
<tr>
<td>Lube chemistry (IR)</td>
<td>Detect contamination by water or glycol</td>
<td>All systems where extended drain is practices</td>
<td>Infrared energy radiation equipment</td>
<td>95% OJT in lab techniques</td>
<td></td>
</tr>
<tr>
<td>Total Acid Number</td>
<td>Indicate lube oxidation or contamination of system</td>
<td>All systems where extended drain is contemplated or where environment has potential to provide acid contamination</td>
<td>Titration solvents</td>
<td>95% OJT in lab techniques</td>
<td></td>
</tr>
<tr>
<td>TAN</td>
<td>Monitor lube drain extension</td>
<td>All systems where extended drain is contemplated or where environment has potential to provide acid contamination</td>
<td>Titration solvents</td>
<td>95% OJT in lab techniques</td>
<td></td>
</tr>
<tr>
<td>Ferrography</td>
<td>Provide information:</td>
<td>All systems</td>
<td>Slides</td>
<td>95% OJT in lab techniques</td>
<td>On-site availability of equipment is highly desirable&lt;br&gt;</td>
</tr>
<tr>
<td>Microterrography</td>
<td>Amount of particulates</td>
<td>All systems</td>
<td>Magnet</td>
<td></td>
<td></td>
</tr>
<tr>
<td>or Full Ferrography</td>
<td>Visual ratio of particulate sizes</td>
<td>All systems</td>
<td>Solvent</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Distinguish types of particles</td>
<td>All systems</td>
<td>Microscope</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Particulate nature</td>
<td>All systems</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Detect potential failures</td>
<td>All systems</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Method/Technique</td>
<td>Purpose</td>
<td>Application</td>
<td>Equipment</td>
<td>Operator Training</td>
<td>In House vs. Contractor</td>
</tr>
<tr>
<td>------------------</td>
<td>---------</td>
<td>-------------</td>
<td>-----------</td>
<td>------------------</td>
<td>------------------------</td>
</tr>
<tr>
<td>Direct reading</td>
<td>Provide information:</td>
<td>Rotary systems which typically have no filtration or where tube is opaque</td>
<td>Capillary</td>
<td>95% OJT in lab techniques</td>
<td>On-site availability of equipment is highly desirable</td>
</tr>
<tr>
<td>Ferrography</td>
<td>Amount of particulates</td>
<td>Gear systems</td>
<td>Magnet</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Visual ratio of particulate sizes</td>
<td>Plain bearings</td>
<td>Microscope</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Distinguish types of particles</td>
<td>Accessible high voltage installations</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Particulate nature</td>
<td>Boiler casings</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Wear nature</td>
<td>Low voltage distribution</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Detect potential failures</td>
<td>Piping</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Relay panels</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Thermography</td>
<td>Locate temperature gradients</td>
<td>Electrical connections and major components of electrical distribution systems</td>
<td>Machining</td>
<td>Approximately 5 hours of formal training for &quot;fair&quot; equipment to approximately 40 hours of formal training for &quot;excellent&quot; equipment</td>
<td>Off-site contractors schedule surveys up to a year in advance</td>
</tr>
<tr>
<td></td>
<td>Define specific temperatures</td>
<td>Accessible high voltage installations</td>
<td>Equipment rack</td>
<td>Contractors usually not on call for follow-up survey requirements</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Detect degradation of electrical connections and major components</td>
<td>Boiler casings</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Performance</td>
<td>Direct trends in equipment performance indicating wear or fouling</td>
<td>Low voltage distribution</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>testing</td>
<td></td>
<td>Piping</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Relay panels</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Various installed standard mechanical and electrical instrumentation</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Acoustical</td>
<td>Monitor low level sounds produced within material subjected to stress</td>
<td>Bearings</td>
<td>Monitoring machinery</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emission</td>
<td>Determine stress and possible crack development</td>
<td>Turbine shafts</td>
<td>95% OJT</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Monitoring (AEM)</td>
<td></td>
<td>Valves</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Piping systems</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Heat exchangers</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Monitoring machinery</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Borescoping</td>
<td>Examine machinery without complete disassembly</td>
<td>Pumps (impeller blades, casings)</td>
<td>Borescope Camera</td>
<td>100% OJT</td>
<td>On-site availability of equipment for use is highly desirable</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Rotating equipment</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
2.5 Task Frequency Selection

2.5.1 Introduction

The determination of the frequency of a task is an art supported by data and experience. Ideally, the task should be scheduled just before incipient failure. This is the goal of predictive maintenance. On the other end of the spectrum, tasks can be scheduled at such a short interval that a lot of useless data is collected. The desired objective is a balance of scheduled preventive tasks and predictive inspections to meet manpower, budget, and availability goals. Task frequency determination is a primary factor in achieving these goals. The goals may not be realized immediately, but through an effective feedback program, the frequencies and scope of the tasks can be adjusted so that the goals will be met.

Several different methods can be used to determine frequency. Probably the most common method is experience, and certainly no matter which method is used, experience should be considered. The operating experience of the plant equipment is usually reviewed and compared with manufacturer's recommendations. The experience method has had various degrees of success. The degree of success can be improved by analyzing the task frequencies established by experience with an analytical method. In this section four analytical methods will be presented.

- Mean Time Between Failure (MTBF)
- Plotting Failures
- Reliability/Probability
- Data Reduction

2.5.2 Mean Time Between Failure

Using mean (average) time between failure (MTBF) to adjust or determine frequencies is not actually a method, it provides supporting data. MTBF is used as a statistical
method to define probabilities of failure. Raw MTBF data only supports the decision that a task should be performed at a specific frequency. MTBF data should be considered when no predictive or preventive tasks are being performed. MTBF is affected by the accomplishment of these tasks.

If a component’s MTBF is 1,000 hours, and a new maintenance program is instituted to increase this time, the new task should be accomplished at a greater interval than 1,000 hours or there will be little or no benefit. However, the new MTBF is not known, and it may not be desirable to extend the operation without data or experience. In this situation, the component can be inspected at 1,000 hours and the data collected can be reviewed to make a decision to establish an extended time period between tasks. At first this is an increase in manhours, but over time manhours are decreased.

2.5.3 Plotting Failures

A slightly more analytical approach to determining the frequency of a task is to plot the frequency of failures versus the operating hours. This method is suitable when a large population of equipment and data are available. If the equipment data are from several plants, the result may not reflect the conditions at your plant, so a conservative approach should be considered. This method is particularly suited for redundant components where the plant can afford to have some of them shut down. Also, the plant must be willing to absorb the additional costs due to the failure, which should be considered as part of the cost analysis.

The plotting method requires considerable amounts of data, namely lengths of run time between failures. When a specific task is being evaluated, the failures considered should only be those which the task is designed to prevent. In the following example (Table 2-6), it is assumed that the pumps failed for the same problem each time.

These data can be plotted as shown in Figure 2-1. The mean is 1,011 hours, so the data dictate that 50% will fail by 1,011 hours. The vertical line defined by the mean actually divides the area under the curve into two equal areas.
If the plant could still achieve maximum availability with 30% of the pumps failed, plant management, in considering a cost analysis, might agree to the possibility of operating with 20% out of service. The vertical line that defines 20% of the volume under the curve falls at 820 hours. Based on historical data, 20% of the pumps can be expected to fail by 820 hours of operation. So, if the task designed to prevent the failures is accomplished around the 800th hour of operation, it can be expected that 80% of the pumps will not fail. Now depending on the duty required, the value of 800 hours can be incorporated into a maintenance schedule.

<table>
<thead>
<tr>
<th>Cooling Water Pump No.</th>
<th>Running Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td>1250</td>
</tr>
<tr>
<td>8</td>
<td>1450</td>
</tr>
<tr>
<td>1</td>
<td>1000</td>
</tr>
<tr>
<td>4</td>
<td>1500</td>
</tr>
<tr>
<td>6</td>
<td>1000</td>
</tr>
<tr>
<td>2</td>
<td>1250</td>
</tr>
<tr>
<td>3</td>
<td>700</td>
</tr>
<tr>
<td>7</td>
<td>600</td>
</tr>
<tr>
<td>8</td>
<td>500</td>
</tr>
<tr>
<td>6</td>
<td>1250</td>
</tr>
<tr>
<td>1</td>
<td>1000</td>
</tr>
<tr>
<td>2</td>
<td>1450</td>
</tr>
<tr>
<td>5</td>
<td>700</td>
</tr>
<tr>
<td>4</td>
<td>1250</td>
</tr>
<tr>
<td>5</td>
<td>1000</td>
</tr>
<tr>
<td>3</td>
<td>700</td>
</tr>
<tr>
<td>8</td>
<td>600</td>
</tr>
<tr>
<td>1</td>
<td>1000</td>
</tr>
</tbody>
</table>

Table 2-6 Example of Pump Failures
In a previous chapter, the equation to perform an economic analysis was given.

\[ PM_p + P_o (CM) + A_o + E_o < > PM_i + P_i (CM) + P (A_i) + P (E_i). \]

Adjusting the frequency of the task changes the probability, which in turn will vary the financial benefit. Performing a PDM task at an increased frequency can result in an increased cost, depending upon the values of the elements. However, once the PDM task is analyzed to the point of completing the above equation, it is a simple calculation to substitute additional time periods into the calculation to determine what the additional payoff would be. The financial benefits for each frequency considered can be compared in a ratio format. This yields a quantitative and comparative value for later review, which would come after the scope of the total program is established.

The probability of failure is always a reality. The goal of the maintenance program should be to reduce the probability of failure through performing those tasks defined in this reliability review. In reducing the probability of failure, the probability of operation...
is increased. The probability of failure plus the probability of operation equals one (1), and this is expressed below as a function of time.

\[ P(t) + R(t) = 1 \]

where:

\[ P(t) = \text{Probability of Failure as a Function of Time} \]
\[ R(t) = \text{Probability of Operation as a Function of Time} \]

**Calculating Reliability**

The calculation of reliability is a statistical method assuming a standard distribution for which the shape is affected by the mean time between failures (MTBF). The steps in calculating reliability are:

- Calculate MTBF
- Calculate Failure Rate
- Calculate Reliability

1. **Calculate MTBF:**

The MTBF is the sum of the lengths of time the component operated between failures divided by the number of failures, and is expressed in "hours."

\[ \text{MTBF} = \frac{T + T + T + T + T}{5} \]

2. **Calculate Failure Rate (λ):**

The failure rate is how many failures will occur each hour, expressed as "per hour," and is the inverse of the MTBF.

\[ \lambda = \frac{1}{\text{MTBF}} \]

3. **Calculate Reliability (R(t)):**
Reliability is the standard distribution and is expressed as a function of time.

\[ R(t) = e^{-\frac{t}{MTBF}} \]

Reliability changes as a function of time means that, based on the MTBF, the component's reliability changes as the length of time it operates changes. The longer it operates, the lower the reliability becomes, and the higher the probability of failure becomes.

2.5.5 Using Reliability

Reliability is the weighting factor applied to the elements on the right hand side of the cost analysis equation. The analysis assumes that the reliability is going to increase by so much as a result of increasing MTBF. The change in reliability is then calculated by estimating the increase in MTBF and evaluating for reliability over the time frame. The equation can then be evaluated for varying frequencies. Varying the frequency affects the time of operation (T), and will therefore affect the cost benefit. The change in cost benefit is a primary consideration when evaluating the frequency of performing a task. A point is reached where no benefit is gained for increasing the frequency.

The methods illustrated to calculate probabilities are suitable for evaluating single components only. When it is desired to evaluate more than one component, such as like components in parallel, series, or a total system, probabilities of the components are combined using additional equations which depend upon system configuration. In addition, the status of the component, for example, operating standby or shutdown standby, affects the combination of the equations. An example is presented to illustrate how the ratio can be derived.

Table 2-7 shows how the probability of failure decreases over the range of not performing the task to performing it every two years and then each year. The failure probability is lowest for performing the task each year, because the time frame for operation (T) is shortest. The cost due to failure is the same for each case, but the
expected cost, weighted by the probability of failure varies proportionally with the value of probability.

The benefits in performing the task can be found by comparing each of the values to the expected cost of $25,600:

- No Task: $0 benefit
- Each Two Years: $12,800 benefit
- Each Year: $16,000 benefit

<table>
<thead>
<tr>
<th>INSPECTION FREQUENCY</th>
<th>PROBABILITY OF FAILURE (A)</th>
<th>COST DUE TO FAILURE (B)</th>
<th>EXPECTED COST DUE TO FAILURES (A X B)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NONE PERFORMED</td>
<td>.32</td>
<td>$80,000</td>
<td>$25,600</td>
</tr>
<tr>
<td>ONCE EVERY 2 YEARS</td>
<td>.16</td>
<td>$80,000</td>
<td>$12,800</td>
</tr>
<tr>
<td>ONCE EVERY YEAR</td>
<td>.12</td>
<td>$80,000</td>
<td>$9,600</td>
</tr>
</tbody>
</table>

Table 2-7 Expected Cost Due to Failures

The next step is to determine the excess of benefits over the cost of performing the PM task, which is $7,500 each time it is performed. Table 2-8 shows that excess of benefits over the cost is the difference between the benefit and the cost of performing the PM task. Then the ratio of benefits to costs is calculated.

<table>
<thead>
<tr>
<th>INSPECTION FREQUENCY</th>
<th>BENEFITS (D)</th>
<th>COSTS (D)</th>
<th>EXCESS OF BENEFITS OVER COST (C-D)</th>
<th>BENEFITS COST RATIO (C/D)</th>
</tr>
</thead>
<tbody>
<tr>
<td>NONE PERFORMED</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>Not Defined</td>
</tr>
<tr>
<td>ONCE EVERY 2 YEARS</td>
<td>$12,800</td>
<td>$7,500</td>
<td>$5,300</td>
<td>1.71</td>
</tr>
<tr>
<td>ONCE EVERY YEAR</td>
<td>$16,000</td>
<td>$15,000</td>
<td>$1,000</td>
<td>1.07</td>
</tr>
</tbody>
</table>

Table 2-8 Benefits Over Cost
Thus, inspections at one year and two year intervals are improvements over no inspections as evidenced by a positive benefits over costs and a benefits/cost ratio greater than one. It cannot be concluded yet whether inspection at two-year intervals is an improvement over inspection every year based only on the higher benefits ratio.

The next and final step is to compare the benefits gained in performing the tasks at the two frequencies. Table 2-9 illustrates the calculations. The numbers show that the benefit of performing the task each year is only a fraction of the cost required to perform the PM task. Therefore, the performance of the task at the increased frequency actually costs the plant more money than it is effectively saving, which is the difference in the benefit and cost. The second benefit to costs ratio being less than one is a similar way to consider the cost. If it were greater than one, the benefit would outweigh the cost.

This method is affected by the probability of failure which is varied by changing the value of (T). The method uses the same principle previously discussed; that of looking at two sides of the equation and comparing the values, the difference being the benefit. The ratios point out immediately when the cost becomes greater than the benefit, because they will be less than one in these cases. This example did not incorporate availability or equipment life into the calculation, but they can be included and added to the costs.

<table>
<thead>
<tr>
<th>INSPECTION FREQUENCY</th>
<th>EXPECTED COST DUE TO FAILURE</th>
<th>BENEFITS (E) (relative to inspection each 2 years)</th>
<th>COSTS (F) (relative to inspection each 2 years)</th>
<th>BENEFITS COST RATIO (E/F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>ONCE EVERY 2 YEARS</td>
<td>$12,800</td>
<td>$0</td>
<td>$0</td>
<td>Not Defined</td>
</tr>
<tr>
<td>ONCE EVERY YEAR</td>
<td>$9,600</td>
<td>$3,200</td>
<td>$7,500 (additional inspection costs)</td>
<td>0.43</td>
</tr>
</tbody>
</table>

Table 2-9 Benefits Versus Cost
An alternative to using the probability method could be to define the reliability desired and solve for the time. This would be expressed as:

\[ \ln(R) = -\lambda(T) \]

Where \( R \) is defined and \( T \) is solved for. This can be another input to the decision making process. As with all of the work done with probabilistic analyses, one assumption must be made, and for these methods the increase in MTBF must be estimated.

2.5.6 Data Reduction

Data reduction is the most reliable method of predicting failure. It uses data specific to the component to establish a frequency for preventive and predictive maintenance tasks. The limitation of the data reduction method is that a significant amount of data over a long period of time is required. Additionally, limits must be established.

Data reduction is the way the plant can change over from a preventive maintenance program to a predictive maintenance program with a high level of confidence in correcting the failure just before the occurrence. The data are collected in the process of performing preventive maintenance and trended over a period sufficient to establish a pattern. For example, the overhaul of a boiler feed pump is accomplished every six months and has been for the past three years. Each time the pump is overhauled, various clearances, including journal and thrust bearing, wearing ring, inter-stage seal, and total float, were measured and recorded. In some cases not all of the parts were replaced, so some wear data is available beyond the six month overhaul.

These values can be plotted and trended to predict an extended overhaul. The limits of wear must be established, but these are often available from the technical manufacturer, or in some cases can be established through diagnostics. It can be determined that the seal and wearing ring clearances will wear to the maximum limit in twenty months. It may not be true that both settings would wear at the same rate, and in some cases may have to be assumed that the amount of wear is linear over time.
However, the data reduction will probably result in more accurate and reliable frequency determinations and justify the changeover to a predictive maintenance program, particularly when supported by an effective diagnostic program.

2.5.7 Summary

Several statistical and economic methods have been presented to show how to develop initial task frequencies when implementing a predictive maintenance program. They all work and they all provide good results when applied to a situation where they fit. The difficulty is determining which method(s) produce the best results. Often this is a trial and error procedure and requires that the frequency and the data collected be analyzed in the initial stages of the program and at least annually thereafter.

There is no one best way to determine task frequencies. The frequency often depends on the operation and condition of the equipment and the monitoring technique used. Different failures occur over different periods of time and these are not known at the outset of a program. Some typical frequencies are presented in Table 2-10 for your guidance.

<table>
<thead>
<tr>
<th>METHOD/TECHNIQUE</th>
<th>MONITORING FREQUENCY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lube Oil Analysis</td>
<td>· Every six months to once per month (steam turbine bearings)</td>
</tr>
<tr>
<td>Oil Spectrometric Wear Metal Analysis</td>
<td>· Rarely urgent – normally trended data</td>
</tr>
<tr>
<td>Oil Micro-Ferrography Wear Metal Analysis</td>
<td>· Routine basis (every 6 months)</td>
</tr>
<tr>
<td></td>
<td>· Daily (in applications such as startup after turbine bearing replacement</td>
</tr>
<tr>
<td>Oil Physical Property Testing</td>
<td>· Normal trending and analysis of new oil - not immediately required</td>
</tr>
<tr>
<td>Thermography</td>
<td>· 90% of surveys are periodic, ranging from quarterly to annually. 10% of surveys are followup</td>
</tr>
</tbody>
</table>
Table 2-10 Monitoring Frequencies

<table>
<thead>
<tr>
<th>Monitoring Category</th>
<th>Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vibration Analysis</td>
<td>90% of surveys are periodic (monthly, quarterly, semi-annually). 10% of surveys are followup or corrective action</td>
</tr>
<tr>
<td>Ultrasonic Testing</td>
<td>Routine basis (heat exchanger, boiler tubes, feedwater heaters, condensers)</td>
</tr>
<tr>
<td>Performance Testing</td>
<td>Rarely urgent - normally trended data</td>
</tr>
<tr>
<td>Boroscopying</td>
<td>On request basis</td>
</tr>
<tr>
<td>Acoustic Monitoring</td>
<td>On request basis</td>
</tr>
</tbody>
</table>

2.6 Procedures and Training

2.6.1 Introduction

Procedures or work instructions are the key job aids that help ensure proper task performance and documentation. PDM tasks should have procedures that have been formally approved. Work instructions may be used where no procedure is available or required. These instructions should focus on ensuring that the task is properly completed and documented.

2.6.2 Procedures

Procedures should be sufficiently detailed to provide all information required by personnel doing the work. Each procedure should include applicable items such as the following:

- Purpose of Task
- References (Data Sheets, Manuals, Standards, etc.)
- Personnel Requirements (Numbers, Skills)
2.6.3 Training

When selecting staff for a predictive maintenance program, prior background, experience, and training will help determine the type and level of training needed. Basic maintenance training and experience has usually been acquired before entering the predictive program. However, diagnostic and monitoring techniques have not.

At a minimum, training with the specific equipment used in the program is needed. In most cases, the equipment vendor will provide some training with the sale of the equipment. In addition, there are other sources for more intensive and specialized
training available from training vendors and industry courses. Thermographic and vibration analysis training is usually readily available from these sources.

The normal training sources, with the advantages and disadvantages of each, are as follows:

**Vendor Training**

**Advantages**

- Inexpensive - Usually Comes with the Equipment
- Specific to the Equipment
- Develops Good Operating Skills

**Disadvantages**

- Difficult to Schedule
- Difficult to Get Retraining or Training for New Personnel After Initial Purchase
- Generally Does not Build Application Skills
- Does not Build Diagnostic or Trouble-shooting Skills
- Not Specific to Your Plant and Application
- Instructor May not be Skilled (Possibly the Salesperson)

**Third Party Training**

**Advantages**

- Specific to the Equipment
- Develops Good Operating Skills
- Provides Application Skills
- Provides Diagnostic and Trouble-shooting Skills
Customized to Your Specific Application
Easier to Schedule

Disadvantages

Expensive
Difficult to get Retraining or Training for New Personnel
Instructor May not be Skilled with Specific Equipment Needed

In-house Training

Advantages

Specific to the Equipment
Develops Good Operating Skills
Provides Application Skills
Provides Diagnostic and Trouble Shooting Skills
Customized to Your Specific Application
Easiest to Schedule
Instructor Skilled and Knowledgeable about Program, Results and Specific Equipment Problems

Disadvantages

Expensive
Instructor May be Taken Away from Other Duties

Some combination of all three types of training is the ideal situation. Then the advantages of each type can be realized while keeping training cost to a minimum. Diagnostic and troubleshooting skills were not discussed since these would need to be given as part of the overall program instruction. If this training was not given, about all that can be expected from monitoring equipment training is that the data collected will be accurate and consistent.
Some typical training curriculums for various programs are shown in Tables 2-11 through 2-14.

Sample Curriculum 1
This training is specifically for a vibration monitoring program. Successful completion of this training is a pre-requisite to participation on the job (See Table 2-11). The target audience is personnel producing, handling, or using vibration data. Specific skill development training is provided to individuals responsible for a specific task.

<table>
<thead>
<tr>
<th>1.0 Preparatory Reading</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.1 Industry</td>
</tr>
<tr>
<td>1.2 Plant</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>2.0 Time Domain Signal Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.1 Mechanical Analogy</td>
</tr>
<tr>
<td>2.2 Analysis</td>
</tr>
<tr>
<td>2.3 Mean</td>
</tr>
<tr>
<td>2.4 Root-Mean-Square</td>
</tr>
<tr>
<td>2.5 Running Average</td>
</tr>
<tr>
<td>2.6 Product Limitations</td>
</tr>
<tr>
<td>2.7 Time Derivatives</td>
</tr>
<tr>
<td>2.8 Phase</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>3.0 Mechanical Vibration</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.1 Forced Vibration, One DOF</td>
</tr>
<tr>
<td>3.2 Forced Vibration, Two DOF</td>
</tr>
<tr>
<td>3.3 Free Vibration, One DOF</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>4.0 Frequency Domain Signal Properties</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.1 Fourier Series</td>
</tr>
<tr>
<td>4.2 Fast Fourier Transform</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>5.0 Vibration Pickups</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.1 Velocity Pickup</td>
</tr>
<tr>
<td>5.2 Displacement Probe</td>
</tr>
<tr>
<td>5.3 Accelerometer</td>
</tr>
<tr>
<td>5.4 Mounting</td>
</tr>
</tbody>
</table>

Table 2-11 Sample Curriculum 1

2-35
6.0 Filters
6.1 Ideal
6.2 Practical
6.3 Precautions

7.0 Severity
7.1 IRD
7.2 HIS
7.3 NEMA
7.4 Individuals
7.5 Damage Origins

8.0 Diagnostic Methods
8.1 Generalized Cause - Effect
8.2 Unique Characteristics
8.3 Analysis Techniques

9.0 Corrective Methods
9.1 Low Tuning
9.2 Stiffening
9.3 Balancing
9.4 Coupler Alignment
9.5 Bearing Changeout

Table 2-11 (continued) Sample Curriculum 1

The training settings are the classroom and OJT. The instructional methods utilized are:

➤ Lecture
➤ Demonstration/Practice
➤ Discussion
➤ OJT

Various instructional media are used.
Sample Curriculum 2

This training program curriculum is for a PDM program utilizing such methodologies as: oil analysis, thermography, vibration analysis, and performance testing (See Table 2-12).

The target audience is all personnel involved in the program. Training settings are:

- Classroom
- Laboratory
- On the job

Instructional methods used include:

- Lecture
- OJT
- Demonstration/Practice
- Discussion

Various instructional media are used.

<table>
<thead>
<tr>
<th>A. Fundamentals</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Principles of monitoring devices/techniques</td>
</tr>
</tbody>
</table>

| B. Plant Familiarization |

<table>
<thead>
<tr>
<th>C. Data Collection</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Principles</td>
</tr>
<tr>
<td>2. Limitations</td>
</tr>
<tr>
<td>3. Methods (OJT)</td>
</tr>
</tbody>
</table>

| D. Data Analysis |

| E. Diagnostics |

Table 2-12 Sample Curriculum 2
Sample Curriculum 3
This training curriculum is for a PDM program utilizing oil analysis, vibration analysis, and ferrography (See Table 2-13). The target audience is all personnel in the program. Training setting is the classroom. Instructional methods used include:

- Lecture
- Discussion
- Demonstration/Practices

Various instructional media are used. This particular training course lasts five days.

<table>
<thead>
<tr>
<th>A. Fundamentals</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Vibration Analysis</td>
</tr>
<tr>
<td>2. Oil Analysis</td>
</tr>
<tr>
<td>3. Ferrography</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>B. Equipment</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Hands-on Demonstration/Practice on specific equipment</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>C. Measurement</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>D. Balancing Fundamentals</th>
</tr>
</thead>
</table>

Table 2-13 Sample Curriculum 3

Sample Curriculum 4
This training curriculum is for a PDM program utilizing acoustic emission, vibration analysis, gas analysis, oil analysis, ferrography, meggering, and partial discharge testing (See Table 2-14). The target audience is all personnel involved in the program. Training settings include:

- Classroom
- Laboratory
- On the job
Instructional methods include:

- Demonstration/Practice
- Discussion
- Lecture
- OJT

Various instructional media are used.

A. Fundamentals/Overview
   1. Oil Analysis
   2. Gas Analysis
   3. Ferrography
   4. Vibration Analysis
   5. Meggering
   6. Acoustic Emission
   7. Partial Discharge Testing

B. Machine Dynamics

C. Piping Vibration

D. Balancing

E. Case Studies

F. Equipment Demonstration/Practice

G. Diagnostics

Table 2-14 Sample Curriculum 4
2.7 Data Collection

2.7.1 Introduction

Data collection is a labor intensive process, and it must be accomplished as efficiently as possible. A schedule must be developed based on the frequency of collection and leveled for manpower considerations.

2.7.2 Forms

The data should be recorded on a form. The form should be organized so that the individual taking the data does not have to turn many pages. Each entry blank should be defined by the same label appearing on the gauge or instrument, and a range of acceptable readings should be listed to help the data collector evaluate immediate problems. Each entry blank should also be arranged in the logical order that the person would walk around the equipment. That way the process becomes a routine, and routines are easier to periodically perform than tasks. The components should also be grouped by area so that area assignments can be made.

If a computer is used, the computer system should facilitate the taking of data. The system should maintain the schedule, and print out the data taking forms. It will print the forms the same way each time or allow the user to regroup the components as desired. With a computer, once the data points are defined and the schedule input, the tracking is accomplished by the software and monitored by several reports.

2.7.3 Data Input

The data forms provide the user with a timely and efficient method to collect data. The forms also provide the user with an efficient method to enter the data into the computer. The input program is triggered by the data form generated. The component prompts the data taker in the order of the form and the user simply enters the data in the order it appears on the form.
In some systems the data can be fed directly into the computer. This is accomplished through a direct link with the instrument that monitors the parameter. The data can either be trended continuously or a clock can trigger the input so points are periodically plotted.

Another method to input data is to record the data on hand-held digital instruments. These devices can be plugged into the computer or a tape can be entered. The data transfer is then accomplished automatically.

2.7.4 Modes of Monitoring

Several operating modes are used for monitoring and acquiring information from each type of equipment. These operating modes are generally divided into three major categories:

- Continuous (or On-line)
- Periodic
- Startup/Shutdown (Transient)

**Continuous Monitoring**

Continuous monitoring features permanently installed sensors on the machinery and permanent instrumentation in the central control room to warn operators to changes in monitored levels. This type of monitoring can provide notice within one second of when a characteristic exceeds a preset rate of change or an absolute limit.

**Periodic Monitoring**

Periodic monitoring is the routine measurement of equipment around the plant. This entails gathering data at set intervals. Its principal purpose is to detect changes that may indicate the onset of problems which, if ignored, will eventually lead to failure. Measurements are taken regularly (e.g. hourly, monthly, quarterly, or even yearly) and
when recorded accurately, indicate changes which are evaluated in conjunction with other equipment conditions (e.g., bearing temperature) and a knowledge of the maintenance history of the equipment.

**Startup/Shutdown Monitoring**

Startup and shutdown monitoring occurs usually before or after overhauls or turnarounds on critical and problem equipment. Information may also be acquired during testing and commissioning of new equipment.

Table 2-15 contains a comparison of the two major modes, continuous and periodic, listing the advantages and disadvantages of each.

### 2.7.5 Data Manipulation

The most time-consuming task in a manual program is data manipulation. At a minimum, the data must be plotted. They may also have to be standardized for ambient atmospheric conditions, and sometimes the data have to be "smoothed." Smoothing refers to plotting the trend line. This is not always straightforward because data points can jump. Probability functions can be applied to fit the data to a curve. The computer can accomplish these calculations quite easily. The conversion factors for atmospheric temperature and pressure and the smoothing functions can be integrated into the software. Once the data are input, the computer makes the evaluation easier.

<table>
<thead>
<tr>
<th>MODE</th>
<th>ADVANTAGES</th>
<th>DISADVANTAGES</th>
</tr>
</thead>
<tbody>
<tr>
<td>Continuous</td>
<td>- Provides primary machinery protection from catastrophic failure through local/remote annunciation and/or automatic machine trip and shutdown</td>
<td>- High installation cost</td>
</tr>
<tr>
<td></td>
<td>- Provides earlier detection of impending mechanical failure</td>
<td>- Because of high costs, suitable only for critical, high-cost machinery</td>
</tr>
<tr>
<td></td>
<td>- Able to track vibration over all operating conditions</td>
<td>- Can only monitor preselected set of measurement points</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- No flexibility in monitoring different measurement points spontaneously</td>
</tr>
</tbody>
</table>
### Table 2-15 Modes of Monitoring

<table>
<thead>
<tr>
<th>Periodic</th>
<th>Can be used with other data accumulation/reduction devices</th>
<th>Use of simple analysis and comparison (commonly with continuous monitoring) may not detect a particular machinery fault</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>· Severity assessment is continuous</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Abrupt changes (e.g., blade loss) can be more promptly recognized</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Capital investment much less than continuous monitoring</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Data acquisition equipment maintenance less</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Manpower to ensure calibration of data acquisition system less</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· More data can be obtained from a particular machine at a relatively small (increase in cost)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· More measurement locations</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Day-to-day characteristics of machines obtained, thus early indication of trouble is detected</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Manpower required to conduct monitoring</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Personnel may tire of:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· routine</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· paperwork</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· moving instruments</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Serious problems that occur in critical machinery sometimes don’t trend long enough to be detected by a periodic program</td>
<td></td>
</tr>
<tr>
<td></td>
<td>· Inaccurate measurement</td>
<td></td>
</tr>
</tbody>
</table>

#### 2.7.6 Data Display

The display format is critical and the trended parameters for each component should be displayed with a common time axis. In this manner, it is easier to correlate the trends. This can be accomplished manually, but the computer can plot and print the data far faster, displaying them graphically.

Another feature of the output display is the report capability. The computer can produce a variety of reports displaying essentially any data desired by the user. Specifically, the reports should include, at a minimum:

> Data Which Has Not Been Taken
Data Points Which Show a Marked Deviation from the Trend so They can be Further Analyzed

Equipment Which Has a Parameter in the Alert or Degraded Range

The computer can also extrapolate the trends and predict the maintenance required dates. There may be cases where two or more trends for the same component indicate different maintenance dates. Each trend plot should have the dates the data was taken. Furthermore, when the trends are changing, the computer should identify these, plot the change in trend, and print a note.

Trends between identical components can be compared routinely. However, these items are not completely identical. Each component is unique, has its own inherent characteristics, and is assembled with different parts by different people. This is especially true for multiple units at one station. Reviewing these different trends can help solve problems. One unit may be performing a particular maintenance task every six months where the neighboring unit may be performing the same task every year. The computer can quickly print or display a report of the varying trends, and the differences can be investigated. The problem could be as simple as a maintenance technique, such as the clearance on a sliding foot hold-down bolt. It may also be more inherent like a slightly modified foundation. This data review will identify where in-house design changes, such as a reduced diameter journal, have been made.

In addition to the capabilities of the computer to support the mechanics of the trend analysis program, the system accomplishes other tasks inherent in the predictive maintenance program. The trending software can be made to interact with the work order system. When an alert condition exists, a work order can be initiated automatically. From the other direction, when a work order is being planned, the system can call up the trends for the planner to review. It may be desirable to schedule additional maintenance at the same time that another problem is corrected. It is usually more cost-effective to correct all deficiencies when a related task is being performed. This is especially true when the task is a major undertaking, such as lifting a feed pump turbine casing.
A significant portion of the trended data will not be capable of being stored in the computer. These data will consist of photos, strip charts, radiographs, and papers that must be stored in a manual filing system. These documents can be indexed and stored on microfiche, and the index number can then be recorded in the trend analysis database. This provides a quick reference system to call up the microfiche and establishes a permanent link between the hard copy and the files.

Programs are also available that display isometrics of piping systems and boiler tubes. The failure locations can be superimposed over the schematic and a map of the problem areas can be reviewed on the screen. The computer can display a significant amount of data in a way that can illustrate trends and problems at a glance.

A significant amount of data will accumulate over the years of plant operation. The computer provides the capability to store the data over that time and review them for selected blocks of time. The computer can be used to record other data as well. Other tests are conducted and measurements taken during equipment maintenance and overhaul. For instance, the NDE test results for boiler repair welds and the various clearances, such as bearing, wearing ring, seals, and float taken when a pump is overhauled. These data are beneficial in evaluating trends. For example, how much do the wearing ring and seal clearances open as the pump degrades through the operating range? These data can establish replacement criteria and should be retained as part of the component record in the computer. The information obtained from the volumes of data will not only predict failures and schedule routine maintenance requirements, but it will be a database that will provide information to help make life continuation decisions.

2.8 Trend Analysis

2.8.1 Introduction

Trend analysis is the analysis of data plotted over a period of time to identify changes in equipment operation. Trend analysis is an all-encompassing technique. It covers the plotting of test data, such as vibration readings, and the plotting of calculated data, such as efficiencies and temperature differentials. Trending is the basis of a
predictive maintenance program. The trends will identify the rate of degradation, which will establish a date to repair the equipment. This is only possible when limits are established. With established limits, the data can be extrapolated to establish a date to accomplish repairs.

This section will present trend analysis, considering the elements necessary to use the trended data effectively.

2.8.2 Elements of Trending

An effective trend analysis program requires an in-depth knowledge of the plant. Many variables can effect overall output as well as the operation of one item of equipment. Varying a controlled parameter will have an effect throughout the plant. Also, uncontrolled parameters, such as the daily ambient temperature, affects the operation of the plant. Therefore, it becomes necessary to eliminate known variables by removing as many of them as possible before performing the trend analysis. This is accomplished through:

- Repetitive Conditions
- Standardized Conditions
- Limits

The use of a computer that can retain the various equipment's "operating curves" can reduce the importance of the above considerations. But in troubleshooting plant performance, a baseline is required. The baseline is the defined conditions for normal operation.

Repetitive Conditions

Whenever data are compared there must be a common factor or no comparison can be drawn. Plotting pump flow rate against time does not yield any useful information. The flow rate is going to change as the plant output changes. On the other hand, plant output can remain the same and the flow can change depending upon plant equipment configurations. Another example is fuel flow. Fuel flow will naturally vary
with load, but it will also vary with the feedwater inlet temperature, the fuel quality, the air inlet temperature, as well as the overall cleanliness of the heat transfer surfaces.

Pump condition can be determined if the effects of all of the influential variables are known, but this is very labor intensive. To simplify the process, conditions are established, and data are taken periodically under these repetitive operating conditions. This eliminates the effects of other variables, such as load temperature, and makes it much easier to spot the effects of clearance wear, cavitation, and leakages.

System control deviations and instrument sensitivities can vary over the operating range. By taking the data at the same set point each time, the effects of the instruments are minimized.

Another element of trending illustrated in the examples above is the proper selection of the parameters to be trended. The data points must be selected so that the trends will be meaningful. Selecting 600 MW as the repetitive condition, to evaluate a feed pump in a two pump system for example, will still leave too many variables, such as pump speed and feedwater heater configuration. Selecting the pump speed and feedwater heater configuration as the repetitive conditions will restrict the variables to the pump. Then the proper selection of the other pump parameters to monitor will provide the data for effective trend analysis of the pump condition.

2.8.3 Standardized Conditions

Standardized conditions refer to those variables or parameters that cannot be affected by the operator. Normally, these are atmospheric conditions, specifically barometric pressure and ambient air and water temperatures. In a power plant, these ambient conditions affect components such as condensers, pumps, boilers, fans, and heat exchangers.

As the temperature and pressure of air, water, and steam change, the mass per unit volume change, the internal energies change and the mass flow rates change. All these will affect the performance of the equipment. These parameters can be corrected back to standard conditions and thus eliminated as causes of performance
changes. Correction factors can often be found in the technical manual or obtained from the manufacturer. The correction factors can also be in the form of a graph or a table.

Boiler fans, blowers, air compressors, and internal combustion engines, particularly gas turbines, all use air; and the main condenser and auxiliary cooling water, or service water coolers, use water that can vary in temperature depending upon the season. As the atmospheric conditions change, the output of this equipment will vary. In evaluating these components, the data must be corrected to standard temperatures and pressures before it is trended. Calculating standardized values is necessary for other predictive tests such as insulation resistance testing and generator output.

2.8.4 Limits

In performing trend analysis, at least two limits must be established. These are the baseline, or reference, limit and the degradation limit. The reference limit is the operating point, or the value of the measured parameter, for the equipment in an overhauled condition. Ideally, these data are obtained through tests immediately following the overhaul. The degradation limit is the operating point where the component fails to perform its function within required parameters such as flow and pressure for pumps and efficiencies for steam and gas turbines.

Other limits can be considered. These are the design limits of operation and the new limits of operation. The design limits are those to which the equipment was designed. The equipment could actually perform above or below those limits. The actual performance when new corresponds to the new limits, and these are probably more meaningful than the design limits. It is important to pick a realistic limit that can be used as a baseline when comparing future test and monitoring data.

The baseline or reference limit is the operating point that the component should be returned to after each overhaul. The reference limit will probably not be the same as the new limit since some degradation occurs over years of operation that is not restored in an overhaul. This is satisfactory as long as the reference limit remains
constant. When the reference limit is not constant, the cause should be determined and corrected. In some cases, the equipment item may be nearing the end of its useful life and require replacement.

For example, a particular piece of equipment is overhauled every two years. The overhaul times are determined by a trending program including vibration signature. After each overhaul the reference vibration signature returns to the same levels. However, after a long period of time, the reference vibration signature begins to change. This could be the result of a gradual degradation in the foundation or the concrete or structural steel experiencing some fatigue. Plotting the vibration over time will identify short term degradations, but by plotting the reference limit over several years, long term changes due to aging or overall wear can be spotted.

The degradation limit is the point at which the component being monitored should be scheduled to be overhauled because it is nearing the point where it will fail to perform its function. Not every monitored parameter must have an established limit, but key parameters must have limits if the need for maintenance is to be predicted.

Degradation limits can be established through several methods. This limit is sometimes set by the manufacturer or supplier. One common example is lube oil condition. Often, it is an industry accepted standard, as it is for insulation resistance. Guidance obtained from a general graph or table, such as a vibration severity chart, can be used to establish limits. Limits can also be set by experience.

The degradation limit is often defined by system requirements. The boiler feed pump must provide a specific flow rate to support full load operation. The main condensate pump must move so much water, at specific head, and the feedwater heater must transfer so much heat at certain flows. These limits are often the full load values. If the equipment cannot produce these flows, pressures, etc., the unit cannot produce full load. This results in a unit derating. When an item of equipment is still operating but not producing the required output, it has suffered a functional failure.

The difference between the reference and the degradation limits is the operating region. Extrapolating the trend through the operating region to the point where it intersects the degradation limit identifies the predicted failure date. Maintenance can
now be scheduled with enough lead time to prevent performance degradation from reaching the functional failure point.

The total system should be considered when establishing the degradation limit. If one pump can support a system and two are available, the decision on where to establish the degradation limit is not straightforward. First, the single component must be considered. If one pump can support the system down to 85% of its capacity, then it has a 15% operational range before maintenance is required. With two pumps available, 200% capacity, and 170% required to support plant operation, one can then degrade to 70% capacity, provided the other remains at 100% capacity. So 30% degradation, or a 70% range, is one possible degradation limit; the other possibility being 15% degradation.

The limit can be established somewhere between 15% and 30%. The lower limit corresponding to maximum degradation is probably not prudent. The upper limit may be too restrictive. Factors that need to be considered are:

- Effect on availability
- Time to Degrade to Both Limits
- Magnitude and Cost of the Maintenance
- Probability of Failure During the Two Time Frames

This is a reliability decision supported by a cost-benefit analysis to determine frequency.

The mode of failure must be considered in establishing degradation limits. The equipment must be able to operate up to the degradation limit before it catastrophically fails. Vibration severity charts accomplish this. Vibration severity charts indicate the maximum vibration the component can endure and not fail.

It is advisable to also define an alert limit. An alert limit is a built-in buffer zone. Once the component data has entered that buffer zone, or gone beyond the alert limit, it may be prudent to double the frequency of the monitoring. The range of the alert limit will depend on the rate and range of degradation, as well as available manpower. If the rate of degradation is such that the component will reach the alert region in two
years and have another six months of operation remaining, the decision to schedule an overhaul every two years will be cost-effective. In any event, establishing an alert range will trigger more closer observation of the equipment and serve as a planning initiator. Once the alert range is entered, job planning can begin. The repair or overhaul can be scheduled, parts ordered, and a work order initiated.

When a limit is set without having a maintenance history to refer to, there is no way of knowing if the equipment can sustain operation up to that limit. In those cases, the experience of the various personnel involved with the equipment may help. For example, experience may have shown that a pump capacity will degrade to a certain point, and the pump will just continue to run with no further degradation.

2.8.5 Computerization

Trend analysis can be very labor intensive. The amount of data can be significant. The effort to collect and assimilate the data may be rather overwhelming. Not everything can be monitored or appraised. The purpose of equipment selection is to identify those items that will affect availability and then define what can be monitored within the manpower and financial budget. Nonetheless, if the program is not managed efficiently, it will become too cumbersome and the individuals will lose interest. Therefore, it is important to manage the data wisely and to use them to provide information in a format that is easy to understand and use. This usually means computerization of the data input and trend analysis.

Several general statistical software packages are available to trend and curve fit the data. In addition several specialty software houses now offer trending programs with their maintenance management programs. Several of the most useful and easy to use programs are those offered by various vendors of vibration analysis equipment. They offer microcomputers that are used to directly record vibration information that can then be downloaded to a personal computer and trended. Some programs now use bar codes to identify the points and will automatically record signatures. Other data may be entered, however, they cannot be trended. While these programs are good, they are limited. Some utilities have developed their own programs completely or used a statistical program as a start.
A trend analysis program essentially involves validating data, plotting the data, and displaying the data. The program will usually curve fit and will be able to extrapolate to a set limit, thus giving a predicted date that the limit will be reached.

These tasks can be performed manually, but are limited by the volume of data. A computer supported trend analysis program can result in substantial savings and a more effective predictive maintenance program. The computer accommodates more data, efficiently schedules appraisals, and manipulates the data in a fraction of the time required to do it manually. The computer performs the major tasks of assimilating the information, manipulating, and displaying the data.

The analysis step still requires direct interpretation. Most systems will present the data and extrapolate the curve. The analyst still has to compare the trend to previous trends for the equipment or similar equipment, evaluate the different types of data, and then diagnose potential or actual problems.

Some simple diagnostics can be accomplished by computer programs using a simple rule-based system. Some companies are developing expert systems based on data for several parameters and using complex rules based on the experience of knowledgeable troubleshooters.

2.8.6 Trending Predictive Data

Some monitoring and diagnostic techniques can be used with trend analysis. Some methods yield numerical data that can be entered into a computer, while other methods produce hard copy records that are filed and compared. Fiber optics is probably the single method discussed that does not produce trendable data. It is used more for inspection and verification. However, fiber optic systems can produce photographs, and these should be maintained to support maintenance requirements such as fan blade cleaning.

Ideally, a system of divided responsibilities should be established to maintain the data systems, both the manual and computerized files. A person should be assigned who
will manage a team assigned to collect the data. These people take, review, enter, file, and evaluate the data. Data should be reviewed before being manually entered into the system. This will eliminate entering erroneous data and allow questionable readings to be checked again to make sure that they are correct. Automatically input data should be checked immediately after input to make sure they were all transferred correctly and to spot any alarm or alert limits that have been reached. This will also ensure problems requiring timely attention are evaluated immediately.

Data display is a factor in an effective trend analysis program. The organization of the data on the page or screen will save time in the evaluation process. The data for one component should be displayed vertically on a common time axis. The extrapolation of the trend should be calculated and printed, and if the trend is changing over time, this should be noted.

The frequency of taking the data should be the same for all data used for diagnostic analysis. The frequency of the analysis will vary with manpower availability and should be established based on the failure history of the equipment. Monthly inputs are desired whenever possible because that produces twelve data points each year. Quarterly data monitoring is generally recommended as the minimum frequency. This will yield at least four points a year, which is the minimum to establish a trend. Most equipment has some major maintenance performed every two years. This then results in eight data points before an overhaul is performed.

The frequency may have to be adjusted to determine if a new trend is forming. This may impact on manpower, but manpower limits may change as more trends are identified and more components are then shifted over to the predictive maintenance program.

**Trending Vibration Data**

A vibration analysis program will produce a significant amount of numerical data. There will also be hard copy data such as strip charts and spectrum analyses to be filed. Vibration data should be taken and entered at least quarterly. The spectrum
should be taken and analyzed as needed (usually as overall vibration reaches alert limits).

The main turbine and feed pump should be monitored continuously since this equipment is vital and critical to plant operation. On units where the booster pump and feed pump are coupled to the same turbine, the booster pump should also be monitored continuously. It may also be cost justified to provide continuous monitors on the boiler fans since they are prone to vibration problems.

Other components can be monitored using portable vibration equipment. All major rotating equipment in the plant should be included. The list should include motors that are also monitored for insulation resistance.

These components are also candidates for bearing temperature monitoring, and ideally the data should be taken at the same time. The data from each method are complimentary and, when they are reviewed, will help in the diagnosis. Some portable vibration recorders now have a built-in thermocouple to automatically record temperature when vibration is measured.

Portable vibration monitors require some care to ensure consistent data. The instruments should be calibrated frequently. The data should be taken using identical and reproducible techniques. This may require that the same individual take the data all of the time, which is not always possible. The data should also be taken from the same point each time. This will require that the points be marked, and if "feet" are used to which the probe is contacted, they must be checked each time to ensure they are secured and replaced if they fall off. As a general rule, vibration readings should be taken on all bearing locations as a minimum.

_Trending Oil Data_

A lube oil analysis program will generate a considerable amount of data. Much of the data will be numerical and suitable for entry into the computer. The test results should also be logged, and the test reports filed. Typically, the data should include sediment, moisture, viscosity, particle count, wear metal contents, and the total acid
number. As with other trended data, they should be displayed on a common time axis for meaningful comparison.

The lube oil analysis program should apply to any equipment with a lube oil sump. This includes the turbine control system, the main turbine, the feed pump and turbine, the diesel and the associated fuel pump, any large motor bearings, and the pulverizers. Tests should be accomplished quarterly on these components, and as often as necessary when a contamination problem is suspected or identified. It is good practice to make visual checks each day for critical equipment and then extend the interval based on the findings.

**Trending Non-destructive Evaluation Data**

Non-destructive evaluation (NDE) tests pose a more complex data management problem. Ultrasonic test data is usually in the form of strip charts, although some ultrasonic thickness (UT) testers will yield numerical data. The eddy current (ET) and radiograph data will primarily be in the form of strip charts and photos. The numerical data is entered into the computer and referenced to the manual file containing the hard copy records.

Ultrasonic testing of plant components and piping systems will produce trendable data. However the trends will have to manually produced, since the data is difficult to reduce. The number of readings taken is considerable. Ultrasonic testing is done when systems are shut down, so the frequency of taking the data is restricted and is done annually or every other year. Thus, it takes several years to develop a trend.

Ultrasonic tests to determine pipe and boiler casing thickness should be conducted annually. This specifically applies to frequent failure areas such as the low spots, elbows, reducers, bottom blow piping, all boiler casings, and boiler tubes. Other high failure areas are the coal system pipes, including the ash pipes and the burner necks or elbows. The coal system should not be restricted to just the low spots or elbows. The straight areas should also be inspected at pre-defined locations. Other straight sections of piping systems should also be inspected using UT methods, but not at the same annual frequency. It is normally sufficient to inspect these sections every five
years. The frequency of the inspection should be established by the frequency of failure.

Eddy current testing of condenser, feedwater heaters, and boiler tubes is also done when the systems are shut down. Like UT testing, this appraisal becomes an annual or less frequent task performed during outages. The data are normally used to identify tube thinning, but the nature of the data makes them difficult to trend. The data can also be used to predict failure frequencies, facilitate outage planning, and provide information to be used in aging analyses.

UT and ET data require mapping to locate specific locations in boilers, condensers, and feedwater heaters. Correlation of the thickness readings to the exact location in the equipment checked is vital to diagnosing problems and making repairs. The data and locations can be entered into a computer to aid analysis. For the trending to be meaningful, the data for each plot must correspond to the same locations every time.

The computer database must be designed to accommodate multiple locations in a system. The system must also be designed to facilitate efficient data entry. Computer graphics can greatly help by portraying the readings and locations in two or three dimensions.

Radiography techniques can be used in accessible areas. Radiographic data should also be maintained in the same equipment file with other data. Radiographic techniques, however, are more suited for appraisals to determine the suitability of components for further service. Major welds, valves, and other selected components should be X-rayed approximately every five years, and at an increased frequency as the plant ages. The pictures can be retained, and compared. However, they are difficult to trend unless each evaluation is reduced to some numerical value. Radiographic data are not normally used to detect trends.

Trending Thermographic Data

Temperature data are normally trended as part of a performance data trending program. Thermographic data are less accurate than test temperature data since they
only measure surface temperatures. As a result, thermographic surveys are normally taken semi-yearly or yearly and are not usually trended. The type of thermography data depend on the type of equipment used. They may be in the form of temperatures, which can be trended. They may be infrared images which would be filed in the manual file. The images can be compared and the onset of problems detected and diagnosed. Trending the temperature readings will require the exact location to be recorded with the UT and ET test data. In spite of these complicating factors, thermography is a useful method to support a plant predictive maintenance program.

Thermography can also be used as a straight appraisal method. This procedure would involve taking numerous "shots" prior to an outage to determine hot spots. The hot spots could then be further inspected and repaired during the outage. However, trending thermography data can be a more useful method. The hot spots can be more easily identified through comparisons with previous data, and the time between failures can be determined.

**Trending Insulation Resistance Data**

Insulation resistance tests provide quantitative values which can be entered into the computer trending system. The limits can be readily established, and the maintenance requirement can be predicted from the trend.

Insulation resistance monitoring is normally conducted annually. Motors operating in hostile environments should be appraised every six months, especially if they do not operate continuously. In fact, motors that operate in damp environments should be monitored for insulation resistance readings before starting whenever the shutdown period has been greater than one or two weeks. The frequency of the test can vary depending on the environment of each motor. Also, depending on the environment, the windings should be visually inspected for cleanliness and cracking regardless of the result of the test.

**Trending Performance Data**

Performance data, such as turbine, condenser, boiler and generator data, are very easily trended since they are all numeric. Many slowly developing problems, such as
fouling, erosion, and seal leakage, are frequently detected and scheduled for correction using this method. Many of these tests are regularly conducted by the plant engineering staff and plotted either manually or using a computer.

The more involved tests such as efficiency tests, heat rate tests, and air heater leakage tests require specified test conditions and extensive preparations and are infrequently run. Therefore trends are not developed for several years. However, a number of simple tests such as enthalpy drop test, condenser cleanliness tests, and terminal temperature difference test, can be run frequently and plotted to detect trends. The data can be collected as often as every day, but weekly, monthly and quarterly data collections are more common.

Standard conditions are very important for performance data and even simple tests will require at least some planning to ensure that they are taken at the same load or that temperatures, pressures, or flows are held constant to eliminate ambient effects.

The use of trend analysis to evaluate turbine condition is described in the next section.

2.8.7 Using Trending to Detect and Diagnose Turbine Maintenance Needs

The main steam turbine is critical to the operation of any steam power plant and monitoring and diagnostic programs are often established for it. Recording of important data with adequate instrumentation and recording these data can enable accurate analysis for detecting changes in the performance of a steam turbine.

If an operating problem involves change in performance over a period of time, such as a loss in kilowatt output, it is necessary to have at least two complete sets of data showing the normal kilowatt output and the reduced output. It is also very important to know whether the change occurred suddenly or over a long period of time. Trending of operating parameters with time can be a valuable diagnostic tool. In order to properly evaluate the accuracy of the performance data, information concerning the operating cycle is needed. If a comparative analysis is to be made, one should know if any of the operating parameters have changed.
For the best comparative data, the cycle should be operating in a similar manner for each test, then no corrections for cycle changes need be made. In fact, operating data taken for trending is quite rarely taken with the cycle operating in the same condition. The operating data must therefore be corrected for these variations in operating conditions.

Trending stage pressures with time is a valuable diagnostic tool. It is usually necessary to correct these pressures for variations in operating conditions in order for them to be meaningful. Pressures upstream of the reheater are corrected using the throttle pressure ratio as shown below:

\[ P_{\text{S, corr}} = P_{\text{S, test}} \times \frac{P_{\text{throt des}}}{P_{\text{throt test}}} \]

where:

- \( P_{\text{S, corr}} \) = Stage Pressure, Corrected
- \( P_{\text{S, test}} \) = Stage Pressure, Test
- \( P_{\text{throt des}} \) = Throttle Pressure, Design
- \( P_{\text{throt test}} \) = Throttle Pressure, Test

The correction of stage pressure downstream of the reheater is more complicated because variations in the reheat temperature must be taken into account. Pressures after the reheater (hot reheat and IP turbine exhaust pressures) are corrected as follows:

\[ P_{\text{S, corr}} = P_{\text{S, test}} \sqrt{\frac{P_{\text{throt des}}}{P_{\text{throt test}}} \cdot \frac{V_{\text{throt test}}}{V_{\text{throt des}}} \cdot \frac{V_{\text{hrh des}}}{V_{\text{hrh test}}}} \]
where:

\[ P_{s\text{ corr}} = \text{Stage Pressure, Corrected} \]

\[ P_{s\text{ test}} = \text{Stage Pressure, Test} \]

\[ P_{\text{throt des}} = \text{Throttle Pressure, Design} \]

\[ P_{\text{throt test}} = \text{Throttle Pressure, Test} \]

\[ V_{\text{throt test}} = \text{Specific Volume at Test Throttle Pressure and Temperature} \]

\[ V_{\text{throt des}} = \text{Specific Volume at Design Throttle Pressure and Temperature} \]

\[ V_{\text{thrh des}} = \text{Specific Volume at Test Hot Reheat Pressure and Design Hot Reheat Temperature} \]

\[ V_{\text{thrh test}} = \text{Specific Volume at Test Hot Reheat Pressure and Temperature} \]

### 2.8.8 Extrapolation and Curve Fitting

The ability to take present and previous data and project future performance is critical to a predictive maintenance program. While the quickest and most convenient way to do this is to use a computer or hand calculator, it may be necessary to determine and extrapolate trends through manual calculational techniques. To do so, it is necessary to extrapolate the results based on the present and past test results. Extrapolation requires determining a curve that will fit the data. To do this, an equation needs to be developed for the curve.

The simplest curve is a straight line curve \( y = mx + b \), where \( m \) is the slope and \( b \) is the \( y \) intercept. These values may be calculated as follows:

\[
m = \frac{n \sum_{i=1}^{n} x_i y_i - \left( \sum_{i=1}^{n} x_i \right) \left( \sum_{i=1}^{n} y_i \right)}{n \sum_{i=1}^{n} x_i^2 - \left( \sum_{i=1}^{n} x_i \right)^2}
\]

where:
\[ n = \text{Number of Points} \]
\[ i = \text{Individual Points} \]

\[
b = \frac{\sum_{i=1}^{n} y_i}{n} - \frac{m_i \sum_{i=1}^{n} x_i}{n} = \bar{y} - m\bar{x}
\]

This method is the linear regression method of curve fitting, but there are several others. Another common method is the polynomial method where:

\[
y = b_0 + b_1x + b_2x^2 + \ldots + b_nx^n
\]

The exponential curve is another common curve. It is expressed as:

\[
y = ab^x
\]

and can be calculated using the linear regression technique if it is put in logarithmic form as follows:

\[
\ln y = \ln a + x \ln b
\]

The power function of the form \( y = ax^b \) can similarly be calculated by reducing it to a logarithmic form as follows:

\[
\ln y = \ln a + b \ln x
\]

### 2.8.9 Calculating Trends

Trending helps determine the slow degradation of equipment performance over time. This trend line analysis can vary in approach from a simple graphing of data points to a complex computer-assisted data point analysis. Depending on circumstances, either approach may be indicated, but a reasonable mix of the two would involve using some type of linear regression analysis to find whether a good correlation can be made. The examples shown below will give some insight into the use of trend line analysis.

The data on Table 2-17 detail the performance of a standard feedwater heater with an integral drain cooler. Determine whether any trending is evident.
Terminal Temperature

<table>
<thead>
<tr>
<th>Date</th>
<th>Difference, TTD (°F)</th>
<th>Degree of Approach, DA (°F)</th>
</tr>
</thead>
<tbody>
<tr>
<td>March 1980 (New)</td>
<td>5</td>
<td>10</td>
</tr>
<tr>
<td>June 1980</td>
<td>5</td>
<td>10</td>
</tr>
<tr>
<td>August 1980</td>
<td>5</td>
<td>10</td>
</tr>
<tr>
<td>September 1980</td>
<td>6</td>
<td>9</td>
</tr>
<tr>
<td>October 1980</td>
<td>8</td>
<td>13</td>
</tr>
<tr>
<td>January 1981</td>
<td>9</td>
<td>10</td>
</tr>
<tr>
<td>February 1981</td>
<td>11</td>
<td>11</td>
</tr>
<tr>
<td>March 1981</td>
<td>Down</td>
<td></td>
</tr>
<tr>
<td>April 1981</td>
<td>12</td>
<td>9</td>
</tr>
<tr>
<td>June 1981</td>
<td>14</td>
<td>10</td>
</tr>
</tbody>
</table>

Table 2-17 Feedwater Heater Data

The first step in this problem is to get an understanding of what the data represent and of how they are changing. Trending to determine changes is best handled by plotting the data against time on a graph. Plots of the data are shown in Figure 2-15. A linear regression is then performed to determine if a trend is indicated.

A linear regression may be performed by hand, but the typical programs available on most engineering calculators are more than sufficient. First, an examination of the data is useful. Note that the first graph in Figure 2-15 shows a steadily increasing TTD from August 1980 through the end of the period, while the second graph shows no such constant increase. The TTD data show that no degradation occurred until September 1980, so any linear regression should begin at that point, as opposed to the DA data (which should be analyzed from March 1980). The results of these analyses are shown below. The program used the y-intercept and correlation coefficient for calculating slope.

\[
m = \frac{n \sum_{i=1}^{n} x_i y_i - (\sum_{i=1}^{n} x_i)(\sum_{i=1}^{n} y_i)}{n \sum_{i=1}^{n} x_i^2 - (\sum_{i=1}^{n} x_i)^2}
\]

where:
- \(n\) = Number of Points
- \(i\) = Individual Points

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Figure 2-15  Plot of Data in Table 2-17
In other words, the rate of degradation of the feedwater heater condensing section can be described by:

\[ TTD = (0.724)t + 6.38 \]

To see this more clearly, we can assume the normal TTD in March, June, and August 1980 was 5°F. This can be subtracted from the \( y \) intercept above to show the increase in TTD over normal, which can be expressed as shown below:

\[ \text{Increase in TTD} = 0.724t + 1.38 \]

with \( t \) in months from September 1980.

The correlation coefficient is only 2.7% off its maximum value, so this linear relationship is justified.
DA data are therefore described by:

$$DA = (-0.014)t + 10.32$$

Similarly, the DA in March 1980 was 10°F, which is subtracted from the y intercept above to show the increase in DA. This is expressed as shown below.

$$\text{Increase in } DA = -0.014t + 0.32$$

with $t$ in months from March 1980.

The correlation coefficient in this case is 94.5% off the optimum, so this linear relationship is not justified.

These results indicate that the condensing section of the feedwater heater is subject to some type of fouling (perhaps scaling on a shell side due to incorrect water chemistry control), while the drain cooler section seemingly has no such problems. Another point to note is that the DA data show a fairly high variation at certain points, possibly due to incorrect or infrequent calibration of equipment, hardware problems, or observer error.

Once trends in data such as those above have been found, the trended data may be used to optimize scheduled maintenance or to prevent unplanned outages. Once trends are quantified, it is easy to extrapolate forward to determine the point at which a component will fall below some minimum performance level (see Figure 2-16). Then maintenance can be planned before component failure, rather than after.

![Extrapolated Plot of Performance Versus Time](image)

Figure 2-16 Extrapolated Plot of Performance Versus Time

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2.8.10 Diagnosing Condenser Problems

Several factors directly affect condenser performance. It is important for plant engineers to understand the symptoms and causes of these problems so that performance degradation can be recognized and corrective action initiated.

Figure 2-17 shows the effect of five simulated conditions that might be expected from the condenser over a period of time. Condenser load, absolute pressure, steam temperature (converted from the absolute pressure at saturation conditions), circulating water inlet and outlet temperature, and air leakage are measurements that would be monitored routinely and are plotted over the simulated time period. The terminal temperature difference (TTD) represents the difference between the steam temperature and the outlet water temperature, and the temperature rise represents the increase in the circulating water temperature. The initial temperature difference is the difference between the inlet circulating water temperature and the steam temperature. By recording and checking these or other data periodically, the engineer can get a good indication of what is happening in the condenser.

![Figure 2-17 Typical Condenser Problems](image)

Figure 2-17 Typical Condenser Problems
The following subsections discuss several factors that alter condenser performance.

**Low Circulating Water Flow Rate**

A reduction in circulating water flow rate can be caused by tube plugging or fouling. A reduction in condenser vacuum (an increase in absolute pressure) will occur, which results in an increase in condenser steam temperature. With a constant inlet temperature, the circulating water outlet temperature will increase as will the terminal temperature difference. Operators can watch pump discharge pressures and pump motor current for clues as to tube sheet plugging. Typically, condenser condition can be returned to normal by backwashing or otherwise alleviating the low flow rate.

Correctly designed backwash or reverse flow systems provide the required corrective flushing action to maintain an open water circuit in the condenser while the unit is operating, thus avoiding the frequent and costly shutdowns that would otherwise be needed to open the condenser and carry out the necessary cleaning.

**High Air Leakage**

During a period of high air leakage, when air blankets tube surfaces, condenser vacuum decreases. An increased steam temperature and terminal temperature difference result. The source of an air leak should be located as soon as practical. Possible sources include leaking isolation valves, valve packings, improperly sealed turbine-condenser joints, or condenser shell weld leaks. High air leakage hurts performance at all loads and especially at low loads.

**Fouled Condenser Tubes**

Dirty or fouled condenser tubes affect condenser performance in a manner similar to high air leakage. Condenser absolute pressure increases (with the decrease in vacuum) because of the reduced heat transfer capability. This increase, in turn, results in a higher steam temperature and a greater terminal temperature difference. Poor heat transfer due to tube fouling affects vacuum performance at all loads, but is most noticeable at high loads.

Backwashing has been mentioned as a means for preventing buildup of debris or silt. Algae and slime accumulation can be controlled and minimized by periodically feeding chlorine into the circulating water. Typically, the chlorine is fed for 10 minutes to produce at least one-half part per million chlorine residual at the condenser outlet. Any old algae or slime deposits that have collected can be removed only by mechanical means.
High Inlet Water Temperature

High inlet water temperature does not affect condenser performance per se, but it does affect most of the condenser temperature values and it increases the turbine backpressure. For a constant load, there is no change in condenser differential temperature. However, the increased inlet temperature means the outlet temperature and steam temperature also increase. This leads to a reduction in condenser vacuum (increased absolute pressure) and in terminal temperature difference.

Reduction in Load

A reduction in turbine load does not affect condenser performance per se either, but the effects of this reduction on other parameters must be understood. A reduced load results in a reduced temperature rise across the condenser and thus in a lower outlet temperature. It follows that steam temperature, absolute pressure, and terminal temperature difference will decrease.

Data taken at a different load may be compared with that at the desired load in a manner similar to that shown in Figure 2-18. Load to the condenser is plotted in terms of Btu per hour or KW load versus temperature rise and initial temperature difference (difference between steam and inlet water temperature). "Rise" will be a straight line from zero at no load to the maximum rise at full load. Similarly, the initial temperature difference will also be a straight line.

Figure 2-18 Effect of Changing Condenser Load on Operating Variables

The difference between these two straight lines represents the terminal temperature difference. The rise will be the same line for all operating loads and water temperatures for a given circulating water flow. There will be a separate curve for the initial
temperature difference and the terminal temperature difference for various inlet temperatures.

2.9 Diagnostic Analysis

2.9.1 Introduction

Diagnostic analysis is the evaluation of machinery performance through the analysis of data. The data can be in the form of test data, machinery parameters, and usually a combination of both. It can be a snapshot in time or trended over substantially long periods. Trended data will result in more accurate and meaningful decisions.

Computers are used extensively in diagnostic analysis. Most plants today calculate heat rate by imputing instrument readings directly into a computer. The computer uses the readings to compute the heat rate and efficiencies. Some of these systems can instruct operators in the corrective action required to lower the heat rate or return it to the specified value. Turbine evaluation systems are also available. These systems operate using the same principle in calculating turbine work and efficiency.

Neither of these systems model the entire plant. They are boiler or turbine models. Many other components and parameters throughout the plant affect heat rate and turbine efficiency. Also, the data are not normally presented in a display that can be effectively used for trending performance.

Diagnostic analysis can be performed manually and there are several methods to accomplish this. The manual methods are the bases for the computer programs, and an understanding of the technique will enable the system to be programmed into a computer.

2.9.2 Range Analysis

Range analysis is a method of plotting parameters over a component's operating range. This is a method of analyzing performance but it is not as easy to identify trends using this technique. The process involves relating the desired parameter to the range of operation. For example, a centrifugal pump curve relates flow to head or discharge pressure. The pump curve for a positive displacement pump relates flow to speed or pressure. With those relationships identified, the pressure and flow can be determined and plotted on the curve.

**Range Plotting Application**

Range plotting is a suitable method to identify degradation when it is difficult to establish repetitive conditions. For this reason, it is also suitable for modeling
components on the computer. The range of operation of several parameters can be plotted against one single parameter. The one single parameter should be a parameter monitored to control the component, such as speed for a turbine or fan. Speed is a suitable parameter to relate the other parameters to in most rotating equipment because the speed is either controlled or held constant, as in the case of a motor. The other parameters related are those monitored during operation, such as flow, pressures, temperatures, and horsepower.

These relationships can be programmed into the computer and a result is a model of the component. The model can be used to evaluate the actual performance of the equipment. This program will enable the plant to monitor the equipment at any operating point in the range of operation which usually amplifies the test procedure.

Range analysis is suitable for auxiliary systems that do not operate at a defined condition. That is, the system is normally large and the line-up of components is often varied and cannot be changed for testing purposes. An example of such a system is the closed loop cooling water system. The number of coolers can vary significantly during plant operation, which will affect system flow.

Obtaining and identifying trends will be more difficult in using range analysis. The flow of the centrifugal pump will vary with the pressure, which can be affected by system line-up and the operating point. To identify the trend the flow readings should be compared at the same pressure. The computer can normalize the values obtained in appraisals to the "appraisal point" or a constant pressure. A complicating factor here is that the degradation pump curves have to be modeled for the computer to plot the normalized operating point from which to compare the trends. This introduces additional error due to estimating the degradation curve, in performing the calculations, and considering instrument range sensitivities. In the next section a method more suited to obtaining trends to predict maintenance will be presented. This method requires repetitive conditions.

**Positive Displacement Pump**

A positive displacement pump is an example of a component that is suitable for trending over most of its operating range. The flow rate of a positive displacement pump is directly proportional to its speed, and the relationship is linear. This relationship can be plotted and limits of operation defined. Then the data can be taken at any pump speed and plotted on the curve; or entered into a computer. The location of the point within the satisfactory operating zone will enable one to identify pump degradation. The trend will not be as readily apparent when compared to plotting values for a single condition. Additional uncertainties can be introduced since more variables over the operating range are factored into the problem.
Repeating certain conditions during the test is still important. Normally positive-displacement pumps are controlled by a dumping valve, and the stroke of the dumping valve will affect the flow. The test could be indicating a trend of decreasing flow rate, but the dumping valve position may be open a little further each time, possibly due to wear in the control system. The position of the dumping valve should also be trended or noted during the test. It can then be factored into the interpretation of the data, and an additional test can be conducted to verify that the pump capacity is not degrading, or deviating from the trend.

**Centrifugal Pump**

A centrifugal pump can be trended in a similar manner. The flow rate of a centrifugal pump is affected by the system backpressure. The feed pump can run at a constant speed, and as the feed flow control valve changes position, the discharge pressure and flow rate of the pump will change. The pump curve for the specific pump illustrates this relationship. Conversely, for a positive displacement pump running at constant speed, varying the position of a flow control valve will vary the pressure but not the flow. This means that there are more variables to consider in monitoring a centrifugal pump.

Plotting the values of appraisals for a centrifugal pump on the pump curve will identify degradation. The degradation will be more easily identified if the appraisals are conducted at the same discharge pressure each time, but this will not always be possible, especially on auxiliary systems.

2.9.3 Repetitive Analysis

Repetitive analysis is the process of repeating conditions each time an appraisal is made. The previous section illustrated the difficulties and uncertainties in normalizing and trending over a range. Repetitive analysis reduces the number of variables, and therefore uncertainties, and allows the user to directly compare the flow rate of the pump each time the appraisal is conducted. To illustrate the procedure, an analysis of the boiler feed pump will be presented and several examples of sub-component degradations will be reviewed.

The example will consider both parameter and test diagnostics. The parameter selection, monitoring, and evaluation will be presented for parameters and supported by the test data from vibration and lube oil analysis. In addition to these methods, other techniques can be used to further support evaluations.

- Thermography can be used to identify steam leaks.
During overhaul, the casing, shaft, and bearings can be ultrasonically tested or radiographed to identify inclusions or separations.

Internal readings such as bearing and wearing ring clearances can be plotted, trended, and compared to other test results.

Fiber optics can be used to verify impeller or turbine blade erosion.

Acoustics can be useful in identifying cavitation.

Insulation resistance should be plotted for motor driven pumps. The resistance readings and the motor current can be trended along with the pump parameters to evaluate the system.

When all of the above parameters are monitored and trended, the comparison of the data is called Time Series Analysis (TSA). TSA is a procedure of comparing and correlating trends to gain additional information from which to make decisions. Following is a TSA analysis of a feed pump.

The pump being considered is a turbine driven centrifugal pump. The pump supplies feedwater to the boiler and attemperators, and it has a recirculation line to the deaerator. The coupling will be specified in the examples. Depending on the type of coupling, the trend relationships will vary. The pump and turbine are each supported by two journal bearing and one thrust bearing.

The first step is to define how the test will be conducted. There are two options:

- During Normal Operation
- Taking the Pump Out of Service and Isolating it from the System

The first option is more suited for major equipment that normally requires the plant to be operating, the component is required for operation, and it is time consuming to start and stop. The second option is more suitable for auxiliary equipment that can be easily isolated and operated. Also, in the case of auxiliary equipment, it will be easier to duplicate conditions when the pump is isolated from the system. An example of this is the cooling water pumps. They are usually centrifugal pumps that feed a large system consisting of many coolers. The pressure of the system is affected by the line-up, which in turn affects the flow.

A goal of the program should be to minimize the disruption of the plant and the time required for the appraisal. Furthermore, starting and stopping machinery increases the
possibility of failure and shortens the life of the equipment. In the example of the boiler feed pump, the appraisal will be conducted while the pump is operating, supporting the plant.

The next step is to define the repetitive conditions. These should be the normal line-up and output, the conditions the plant operates under most of the time. First, the overall plant conditions are established. In this case, a plant output of 600 MW is set.

To establish the line-up, the inputs and outputs to the pump and turbine must be considered, and this will define points to check before the test. All other components will be considered to be operating correctly. Other components can affect the operation of the component being tested, but the test should be designed to eliminate these effects. The flow path between the pump and the boiler should be the same configuration for each appraisal. The boiler pressure and the pressure drops through the line will establish the pressure at the discharge of the pump. The boiler operates at a constant pressure and the pump is normally controlled to maintain a set pressure to get water into the boiler. Therefore, the line-up and the discharge pressure of the pump should be repeatable conditions. The other parameters of the pump will vary as the sub-components degrade.

Other inputs and outputs to the pump will affect the trending and are also considered in the evaluation. The pump suction pressure should be a constant value. It will vary with the section head and the line-up between its discharge and the feed pump, but these values should also be constant and steady during the test. The deaerator or condenser level will affect the suction head, and if it is the same each time, the feed pump suction pressure will normally be the same. The value should be trended because it is the relating link between the two pumps.

The discharges from the pump also need to be considered. Since the flow is the primary variable in the plant, all flows must be determined. This pump provides flow to boiler, the attemperators, and the recirculation system. Flow to the attemperators will vary as the boiler conditions change. The attemperator flow should be trended. There should normally be no flow through the recirculation or a relief valve, and these sub-components should be checked, either in the process of taking the test readings or before the test. It is good practice to check them prior to taking the data. It eliminates them immediately from the evaluation of degrading trends if they are satisfactory. If they are leaking, they are identified and the leakage can be approximated. They can be added to a work list. If the pump has a motor operated check value on the discharge, this should be checked to ensure it is fully open.

In performing this evaluation to determine what to establish as a repetitive condition, the parameters not selected will be those trended. For most rotating machinery speed is a very repeatable condition and often a value against which other parameters are
plotted. With the speed constant, any degradation in the pump will be indicated by a decreasing flow rate.

The evaluation of the turbine is performed in a similar manner. There are essentially one input and one output. The work accomplished by the turbine depends on the flow rate, temperature, and pressure of the steam. Normally, the steam temperature and pressure can be considered constant since these come from the same source, and these parameters can be considered the repetitive conditions. If this is not possible, turbine output can be corrected for small deviations in pressure and temperature. The remaining condition is the steam flow. As the turbine degrades, the steam flow increases.

Most plants do not monitor steam flow to the feed pump turbine. If it were monitored, it would be a trendable parameter. However, monitoring the position of the throttle valves will correspond to flow. The work done by the turbine is represented by its speed. So for constant speed, the throttle position should not change, unless there is a problem. Any degradation of the turbine blading would cause this to occur.

The turbine analysis is related to the pump. To maintain the flow to the boiler, the pump must turn at a certain speed and the boiler must supply a certain amount of steam to attain that speed. When the turbine blades begin to erode or become coated where they lose efficiency, the throttle valve will open to admit more steam. If the pump is degraded, also, the water flow will show a decrease in addition to the turbine conditions changing. During plant operation, the speed would probably show a significant increase if both components were degraded. If the pump is binding, the pump trends may not indicate a problem, but the turbine will be turning the same speed with an increase of the throttle position.

It may be difficult to identify the concurrent degradations when speed cannot be a designated repetitive condition. The equipment may have to be isolated to further evaluate it. In the case of the turbine blades eroding and the pump flow decreasing, the speed will increase, as will the throttle position, but the slope of the speed increase should be greater for the two concurrent problems. This may change the length of time between overhauls if the speed is limited by design or by a governor. The steam chest pressure, the throttle position, and control parameter should also be proportionally greater. The evaluator may not be able to identify that the throttle valve or speed reading is greater than for a single problem. This could be further complicated by a fluid coupling that could cause a difference in the speed between the pump and the turbine. A range of operation relationships would identify this condition, but if it is not available, a separate test could be conducted. The speeds could be lowered to the reference value for pump flow and the throttle position can then be checked. If it still indicated an increase over the reference position for equipment operation, a turbine or blade problem might be the cause. Having a history of data
available can be invaluable in evaluating multiple problems. It provides information from which to draw comparisons.

Time Series Analysis can be supported by several other techniques, including the range analyzation method. It can also be supported by other diagnostic techniques such as vibration analysis, thermography, fiber optics, and lube oil analysis. Because there are so many variables and the conditions can vary, the program should be supported by other means mentioned above. Various diagnostic techniques are mutually supportive.

A parameter diagnostic program has several benefits. It can help establish limits for other techniques, such as vibration. The vibration limit may be high and allowing the pump to degrade to that limit may result in the pump not supporting system requirements. The program is a systematic method to identify component deficiencies.

2.9.4 Diagnosis of Turbine Problems

One reason for monitoring turbine performance is that it makes it possible to diagnosis turbine problems. Very often it is possible to do this diagnosis with the unit in service, without opening a turbine section. When the cost of outages and labor are considered, it is obviously of great value to be able to perform such diagnosis.

**Diagnostic Tests**

Several tests can be performed to help make diagnoses. The simplest of these is a maximum capability test. This test is performed by simply bringing the unit to valves wide open with rated steam conditions. A change in the load in this condition is generally an indication of a problem. It is desirable to obtain several other data readings during this test to aid in the troubleshooting. These include:

- Feedwater Flow
- First-stage Pressure
- All Extraction Pressures
- Main Steam Temperature and Pressure
- Reheat Steam Temperature and Pressure
- Reheat Turbine Exhaust Pressure

In addition, the results of enthalpy drop tests in the high pressure and reheat turbines are invaluable. These tests should be performed at valves wide open if at all possible. If it is not possible to reach valves wide open at rated pressure for the enthalpy drop
tests, it is desirable to reduce main steam pressure to make it possible to reach valves wide open. Also, if it is not possible to reach valves wide open for a maximum capability test, taking data over a period of time at a known, repeatable position for trending purposes can be useful. The following is a summary of the sort of behavior one might expect of the parameters that should be monitored.

**Feedwater Flow**

Feedwater flow should be a linear function of load. An increase in the feedwater flow for a given load is an indication of a problem. One possible problem is simply worn seals or an eroded steam path. Either of these could cause increased flow at a given load or reduced load for a given flow. Drains in the steam piping or the turbine that are supposed to be closed in normal operation but are open instead could also cause this problem. Another possible cause of inconsistency in these two parameters could be faulty instrumentation. One may be sure that faulty instrumentation is the cause of the problem if the load appears to go up significantly for the same feedwater flow.

**First-stage Pressure**

Any pressure in the turbine that can be read while the unit is in operation can provide valuable information on the condition of the unit. None is more valuable than the first-stage pressure. Because, as explained earlier in the text, this is the pressure upstream of the first stage and the turbine operates at essentially a constant pressure ratio. The most significant property of this parameter is that it varies in a linear fashion with load. Also, because the turbine control valves are generally arranged so that the total lift of the control valves is linear with load, first-stage pressure should be linear with control valve opening also. If there is any disturbance in these linear relationships, it is an indication of difficulty.

If, for instance, the first-stage pressure were to be less than normal for a given control valve opening, it would be an indication that there is an obstruction in the first-stage nozzle or perhaps the main stop and control valves. An example of such an obstruction is a broken control valve stem. Occasionally, a control valve stem will break within the valve bonnet where it cannot be seen. There will be no external indication that the stem is broken from outside the unit and the valve will appear to open normally because the visible, unbroken portion of the valve will travel normally.

The first-stage pressure could, on the other hand, go up at a given control valve position. It is necessary to look at other parameters to determine a possible cause. If the unit load and feedwater flow go up with the first-stage pressure, it is an indication that more steam is passing through the unit. One common cause for this phenomenon might be that the first-stage nozzle is eroded. Erosion in the first-stage nozzle is a
common problem because the first stage nozzle bears the brunt of any solid particle carryover from the boiler, as it is the first obstacle that the particles encounter. Also, the steam velocities in the first-stage nozzle tend to be higher than elsewhere in the steam path.

On the other hand, the load may well go down when the first-stage pressure goes up for a given control valve position. When this happens, it is a good indication that the steam path downstream of the first stage is obstructed. An examination of other turbine stage pressures can often help to determine the location of the obstruction. If, for example, in a single reheat unit, the cold reheat pressure were to increase by about the same percentage that the first-stage pressure did, and if the first reheat turbine extraction were to fall, it would be an indication that there was an obstruction in the reheat turbine between the inlet and the extraction where the lower pressure was found. Confirmation that this is the problem might be found from the enthalpy drop efficiencies of the HP and reheat turbines. If, in this case, the HP turbine enthalpy drop efficiency was found to fall only slightly, while that of the reheat turbine was found to fall rather substantially, it would be a further indication that the HP turbine was in reasonably good condition, but the reheat turbine had some damage.

**Turbine Stage Pressure**

In the discussion of turbine first-stage pressure, we have already shown how the examination of turbine stage pressures can help in the diagnosis of a problem. The important property of these pressures is that they, as does the first-stage pressure, vary in a linear fashion with load. If the linear relationship is disturbed, it is an indication of some problem.

The pressures that are available for examination, other than the first-stage pressure, are the HP turbine exhaust, the reheat turbine exhaust, and all extraction pressures.

The turbine stage pressures are most often useful in localizing obstructions in the steam path. The pressure upstream of the obstruction may be expected to be higher than normal, and those downstream lower than normal. The percentage of pressure increase upstream of an obstruction usually decreases with the distance away from the obstruction. For example, if there were damage resulting in an obstruction in the first stages of the LP turbine, there might be a substantial pressure increase at the reheat turbine exhaust, while only a slight increase in the first-stage pressure. Pressures downstream of such an obstruction, on the other hand, tend to decrease by about the same percentage all the way to the exhaust of the turbine. If there were an obstruction in the early stages of the HP turbine, all the turbine pressures downstream of the obstruction would be expected to decrease by about the same percentage.
Enthalpy Drop Efficiencies

The HP and reheat turbine enthalpy drop efficiencies are among the most valuable indications of turbine internal condition. It is important to understand how these parameters can be expected to behave and how they can be used to diagnose turbine problems.

The enthalpy drop efficiency of the HP turbine is a strong function of load. Typically, this parameter may vary from about 60% at very low loads to 85% at valves wide open. This means that if there is a problem with the turbine, such as an obstruction of the steam path which results in a reduction of load, it would be normal to see some decrease in the HP turbine enthalpy drop efficiency. This is true even though the HP turbine may be in good condition.

The reheat turbine enthalpy drop efficiency, on the other hand, is relatively insensitive to changes in load. If the reheat section has no extractions (not a common arrangement), then the enthalpy drop efficiency would essentially be independent of load. Most reheat sections do, however, have an extraction. Where this is the case, a relatively slight change with respect to load should be expected, typically from around 93% to 96% at very low loads to 88% to 90% at valves wide open. Thus, a marked decrease in the enthalpy drop efficiency of the reheat turbine is almost always an indication of a problem in that turbine section.

As can be seen from this discussion, it is important to regularly monitor many turbine parameters, such as first-stage and extraction pressure, even though they have no use in calculation of turbine cycle heat rate or other indications of what is commonly thought of as performance. If these parameters are not monitored, the diagnosis of turbine problems when they occur may not be possible when the unit is in operation and fully assembled. The only alternative then is to open up the turbine and hunt for the problem.

The importance of having a good baseline for all these parameters should also be pointed out. This baseline is best established immediately after initial start-up of the unit when it is brand new and known to be in good condition. If that has not been done, the next best alternative would be to establish baseline data after a major turbine overhaul in which the steam path (buckets, diaphragm partitions, and nozzles), seals, and clearances have been restored to factory tolerances.

If a deterioration of any of the parameters discussed occurs, the time over which the deterioration takes place is obviously an important consideration. If, for instance, the first-stage pressure suddenly goes up in a step change, accompanied by a marked reduction in load, enthalpy drop efficiency, and pressures downstream of the first stage, it is quite likely that there has been a mechanical failure inside the HP turbine.
Such a failure might be the carrying away of bucket covers, with debris from the failure lodging in the downstream diaphragm partitions, obstructing the steam path.

If, on the other hand, the same symptoms were to appear gradually over a period of months, it would indicate that there might be an accumulation of deposits from boiler carryover in the HP turbine steam path. If this were suspected to be the case, attention to boiler water chemistry could possibly help, or at least arrest the problem. Also, a special technique called water washing might be used to help correct the problem. Water washing calls for operation of the turbine at low loads with much lower than normal main steam pressures and temperatures. This results in condensation forming in the steam path, which can actually wash away soluble deposits in some instances. If this technique is successful, it can eliminate or postpone the need for an outage to open and clean the turbine. It should be noted that water washing is a very dangerous operation because of the potential for water induction and should be undertaken with the close cooperation of the turbine manufacturer.

Typical Problems

It is apparent that the various types of problems that one might expect to see in the turbine can be classified. The broad classifications are as follows:

- Accumulation of Deposits on the Steam Path
- Erosion of the Steam Path
- Mechanical Damage to the Steam Path
- Seal Wear

It is certainly possible to encounter problems that do not fit into these categories. For instance, the case of the broken valve stem cited earlier does not "fit." It is useful nonetheless to examine the symptoms and causes of these categories of problems.

Accumulation of Deposits on the Steam Path

As mentioned earlier, poor boiler water chemistry can result in the accumulation of deposits in the steam path. Poor water chemistry can result from a number of factors, and might be caused by inattention or lack of understanding of this important parameter. Other problems, such as condenser tube leaks that result in the accumulation of chlorides and silica, can result in difficulty even when good, conscientious control of water chemistry is practiced.

Another problem not related to water chemistry that can result in deposits in the steam path is exfoliation of copper from feedwater heater tubes that use a copper alloy. This type of exfoliation has been a problem principally with feedwater heater
tubes of 70/30 copper-nickel material. It is aggravated in units that have considerable cycling duty because the exfoliation process occurs with temperature cycling.

As might be expected, deposits are most often an efficiency problem in the HP turbine. Usually most of the material that is carried over into the turbine is deposited in the HP turbine. Deposits in the reheat turbine may also be encountered; however, they are generally less severe than in the HP. Exceptions to this rule may be seen in some older units with relatively low throttle pressures.

There is another problem with deposits that generally will not be possible to detect from monitoring of the parameters discussed. Occasionally chlorides and sulfides are carried over in the steam to the turbine. These contaminants remain entrained in the steam until it begins to condense in the last two or three stages of the turbine. At the point of condensation, the chlorides and sulfides tend to concentrate. Generally, they do not accumulate in sufficient quantity to cause any problems that can be detected by the techniques already described. These chemicals create an environment favorable to the phenomenon called stress corrosion cracking. Stress corrosion results in materials yielding under tensile stress that is much lower than normal. Cracking generally occurs prior to failure, and these cracks may be detected using various nondestructive test method. However, except for catastrophic failure, there is no indication without removing the unit from service for inspection.

The effect of the accumulation of deposits on the steam path generally occurs over a period of months, although occasionally a measurable deterioration may be seen over a period of as little as a week, if there are severe boiler water chemistry problems. It is commonly accompanied by decreases in the enthalpy drop efficiencies of the affected sections. The first-stage pressure may be expected to increase for a given valve position, assuming constant throttle steam conditions. At the same time, the feedwater flow and load may be expected to go down. Other stage pressures will also be affected. Those downstream of the deposits may be expected to fall, while those in the vicinity of the deposits may increase, remain the same, or decrease, depending on their exact location with respect to the deposits.

_**Erosion of the Steam Path**_

The second most common problem in the turbine steam path is erosion. Erosion generally may occur from two different problems. The first is solid particle erosion, which results, as the name implies, from particles in the steam wearing away at the metal in the steam path.

The main source of solid particle erosion is oxidation of the boiler superheater and reheater tubes in normal operation. When this occurs, small flakes of oxide are carried over into the turbine and erode metal from the steam path, generally resulting in
gradual erosion and thus gradual deterioration of performance that may occur over a period of years.

The size of the particles of oxide and the fact that the problem can occur over long periods of time means that fine mesh screens over the main steam valve strainers are not an effective means of preventing this problem. Currently, research projects are in progress to evaluate the effectiveness of combating the problem by chromizing and chromating the inside of the boiler tubes. To date, the results of this research appear to be promising, particularly as this boiler tube treatment can be performed on boilers that have been in service as well as on new boilers.

A second cause of erosion is condensation. Over a period of time, water droplets will erode metal in the steam path. Obviously this generally is a problem only where condensation forms in the turbine. For fossil units, this is only, for the most part, in the last two or three stages of the LP turbine. In nuclear units, usually the entire steam path operates with wet steam, and so erosion is more of a problem. Turbine manufacturers often use special designs to minimize the effects of erosion in the wet regions of the turbine.

The most notable of these in the fossil units is strips of hardened material such as Stellite on the leading edges of the buckets in that area. Other special designs, such as moisture removal pockets and serrated bucket tips, are used in nuclear units to help remove moisture.

Erosion causes an increase in load over time at the same control valve position with the same throttle conditions. This is generally accompanied by a corresponding increase in feedwater flow and first-stage pressure, assuming that most of the erosion occurs in the first-stage nozzle, as is often the case. The enthalpy drop efficiencies of the affected sections will decrease significantly.

It is important to understand that erosion is not always easily seen in the steam path when the turbine is disassembled. Sometimes the erosion wears the material away very evenly and leaves a very smooth surface that looks just as good a machined finish. In cases such as these, the only good way to determine the extent of the erosion is by doing an area check of the steam path buckets or nozzles. An area check is performed by measuring the opening between adjacent partitions or buckets at the root, the pitch diameter, and the tip for every opening in the affected portion of the steam path. The total amount of open area is then calculated and compared to the design values for the area. In extreme cases, damage can be seen by looking perpendicularly to the blades. In some cases, a clear path can be seen. Eroded nozzles and buckets can be restored by repair welding, but must be undertaken with extreme care.
Mechanical Damage to the Steam Path

Mechanical damage to the turbine is generally caused by one of two mechanisms, mechanical failure of turbine internals or the introduction of foreign material into the turbine. Foreign material usually gets into the turbine during outages. This material may come from debris, such as weld bead and scale from welding, or it might be dirt and even small hand tools left in the steam piping, boiler, or turbine following an outage. The turbine manufacturers provide strainers in the main steam valves to help minimize this problem. These strainers normally have a coarse mesh screen installed over the strainer holes. There are, however, fine mesh screens that can be installed temporarily when it is known that there will be debris in the steam piping, such as after major tube replacements. The disadvantage of using fine mesh screen is that it cannot be removed without an outage. Thus, often fine mesh screens are not installed, even when the likelihood of carryover of debris is rather high. Obviously that course of action can be a gamble.

Failure of turbine internals may occur in many different ways. Among the more common of these are bucket cover failures. Failures may be induced by operational problems such as water induction or caused by the carryover of debris discussed previously. The result of these failures is often accompanied by the peening over and closing up of the steam path, resulting in a flow restriction and reduced efficiency. If a significant amount of material is carried away from the rotor, a sudden and possibly high vibration may also result. Thus, in summary, mechanical damage may be indicated when there is a reduction in enthalpy drop efficiency, a change in stage pressures that points to a flow restriction, and/or a sudden increase in vibration.

Seal Wear

The turbine interstage seals are intended to control leakage of steam from the steam path. Steam that does leak past the seals bypasses the nozzles, diaphragms, and buckets, and so its energy is not used. Also, the leakage can often disrupt flow and cause further inefficiency.

The seal wear can result from solid particle erosion or, more often, from rubbing. Rubbing refers to the turbine rotor actually rubbing against the seals in operation. Rubbing may be caused by misalignment in construction, imbalance accompanied by vibration, water induction, and thermal transients, which result in differential growth and thus temporary misalignment of turbine internals. It is possible to minimize rubbing by careful operation of the unit in accordance with the manufacturers' recommendations, which are designed to minimize the likelihood of water induction and rapid thermal transients. It is normal, however, to experience some rubbing during the initial operation of a new unit or a unit that has had new packing installed.
It is not always easy to detect worn interstage seals in operation. One indication of probable difficulty is the operation of the steam seal system. Turbine manufacturers generally design the steam seal system to be able to maintain a seal with up to twice the normal packing clearances. When this situation occurs, however, there will be a greater requirement for sealing steam. The steam seal feed valve will have to open more at part load operation, and it may be necessary to open a bypass around the valve to maintain the seals. It is quite likely that when the steam seals are worn, the interstage packing is probably also worn, as both are generally affected the same way at the same time.

Another indication of worn seals is a change in the enthalpy drop efficiency of the affected sections of the turbine. The enthalpy drop efficiency may deteriorate. There is, however, a situation in which it may appear that the enthalpy drop efficiency is improving. This situation can occur in units having an HP-reheat opposed flow section. If the packing between the two sections (the N2 packing) becomes very worn, a large amount of steam at higher pressure and temperature than the steam at the entrance to the reheat turbine will leak into the reheat turbine. The steam conditions that are measured to determine the enthalpy drop efficiency are taken at the inlet to the turbine, however. This results in the enthalpy drop efficiency appearing to be better than it really is for the reheat turbine.

Other indications of increased seal clearances would be increased feed water flow and possibly a reduction in load for a given valve position and rated throttle conditions.
Chapter 3

PREDICTIVE METHODS/TECHNIQUES

3.1 Introduction

A number of predictive methods/techniques were mentioned in Chapter 2. This chapter will describe the following methods/techniques in greater detail:

- Insulation Resistance Monitoring
- Oil Analysis
- Vibration Analysis
- Acoustic Leak Monitoring
- Ultrasonic on-line Bearing Condition Monitoring
- Thermography
- Replication
- Nondestructive Evaluation
- Fiber Optics

3.2 Insulation Resistance Monitoring

3.2.1 Introduction

The most common method of determining the condition of electrical insulation used today is insulation resistance testing and monitoring. The reasons for this are:

- Equipment is Relatively Inexpensive
- Test is Simple
- Test is Quick to Perform
- Test Does Not Damage the Insulation

Insulation resistance monitoring has been recommended and used for more than half a century to evaluate the condition of electrical insulation. Whereas an individual insul-
Insulation resistance test is of limited use, a carefully maintained record of periodic measurements accumulated over months and years of service is a trendable history of the insulation's condition.

3.2.2 Basic Theory

Insulation resistance is defined as the electrical resistance between two conductors separated by an insulating material. In more quantitative terms, insulation resistance is the impressed voltage divided by the total current flow or: \( R = \frac{V}{I} \). The currents that result from the impressed voltage consists of the current leakage over the surface of the insulation and the current leakage through the insulation. The current leakage through the insulation may further be subdivided into:

- **Capacitance Charging Current** is of comparatively high magnitude and short duration, usually has effectively disappeared by the time the first data is taken, so it does not affect the one minute nor the ten minute insulation resistance tests.

- **Absorption Charging Current** which decays at a decreasing rate from a comparatively high initial value to nearly zero. The resistance-time relationship is a power function which when plotted on a log scale is a straight line. Usually the resistance measured in the first few minutes of a test is largely determined by the absorption charging current.

- **Conduction Charging Current** which, with the leakage current over the surface, is nearly constant for a given voltage. This current is predominate after the absorption current has become insignificant.

The current that yields the resistance reading is a combination of the leakage current over the surface, the absorption charging current, and the conduction charging current.

After removal of the impressed voltage there will be evident a discharge of current consisting of two parts.
➢ Capacitance Discharge Current which will decay nearly instantaneously, depending upon the discharge resistance.

➢ Absorption Discharge Current which will decay logarithmically from a high initial value to nearly zero, as does the absorption charging current.

Two Fundamental Properties of Insulation

Two properties of insulation are dielectric strength and insulation resistance. These are two different and distinct properties of insulation and no simple relation between them has been found. However, extremely low values of insulation resistance, especially when measured values have decreased sharply or steadily over a period of time, should be taken as a warning that the dielectric strength may be low or may be decreasing to the point where the insulation will rupture at the service voltage.

Dielectric Strength is the ability to withstand potential difference and is usually expressed in terms of voltage at which the insulation fails due to electrostatic stress. Maximum dielectric strength values can be measured only by testing to destruction.

Insulation Resistance is the resistance to current leakage through and over the surface of insulation. Insulation resistance can be measured without damaging the insulation and furnishes a highly useful guide for determining the general condition of insulation, but is, by itself, not entirely conclusive. Measurements have shown that insulation resistance measurements at moderate voltages may actually increase after the insulation has been broken down by a high potential. Clean, dry insulation having cracks or other faults may show a high value of insulation resistance but obviously is not suitable for use. These limitations of insulation resistance values must be fully realized when the condition of insulation is appraised by such values. An individual insulation resistance test or "spot check" is often used as a "go - no go" test before electrical equipment is placed in service. These tests do not give a good indication of the actual condition of the insulation. Insulation resistance measurements taken over a period of time can be trended to determine degradation of the insulation.
Factors Effecting Insulation Resistance

Insulation resistance measurements are affected by several factors:
- Surface Conditions
- Moisture
- Temperature
- Magnitude of Test Direct Potential
- Duration of Application of Test Direct Potential
- Residual Charge in the Winding

Effects of Surface Conditions

The cleanliness of the plant and area in general will greatly affect the insulation readings and the lifetime of the motor. Foreign matter, such as carbon dust deposited on creepage surfaces, may lower the insulation resistance. This factor is particularly important in the case of direct-current machines which have relatively large exposed creepage surfaces.

Dust on insulation surfaces which is ordinarily non-conducting when dry, may, when exposed to moisture, become partially conducting and lower the insulation resistance. If the insulation resistance is reduced because of contamination or excessive surface moisture, it can usually be brought up to its proper value by cleaning and by drying.

Effects of Moisture

Water and steam leaks, as well as the inherent moisture in the air also seriously effect insulation life. Regardless of the cleanliness of the winding surface, if the winding temperature is at or below the dew point of the ambient air, a moisture film will form on the insulation surface and may lower the insulation resistance. The effect is more pronounced if the surface is contaminated.
Some types of winding insulation are hydroscopic, and moisture may be drawn into the body of the insulation from humid ambient air. Absorbed moisture will have a large effect on the insulation resistance. Machines in service are usually at a temperature high enough to keep the insulation comparatively dry. Machines out of service may be heated to keep the winding temperature above the dew point. In these cases low resistance readings can be corrected through drying, baking the motor in an oven under a hot lamp, or by passing a small controlled amount of direct current through the winding.

When tests are to be made on a machine that has been in service, the tests should be made before the machine winding temperature drops to room temperature. The opportunity may be taken at this time to test at several temperatures for establishing the applicable temperature coefficient if it is not known.

Effects of Temperature

Insulation resistance of most material varies inversely with temperature, and therefore, the test results must be converted to a standard temperature (such as 20°C, 25°C or 40°C) for comparison. As a general rule of thumb, for every 10°C rise in temperature, the insulation resistance doubles. To correct the measured insulation resistance to a standard temperature for comparisons, an insulation resistance temperature coefficient is used. This coefficient is easily determined from a graph such as in Figure 3-1.

When the test is performed, the temperature of the winding is also recorded with the insulation resistance values. The winding temperature is located at the bottom axis of the graph and a vertical line is drawn until it intersects the line on the graph. Then, a horizontal line is drawn from that point to the left and the coefficient, \( K_t \), is read. The corrected value of insulation resistance is calculated using the formula below:

\[
R_c = K_t \times R_t
\]

where:

\[
R_c = \text{Insulation Resistance in Megohms Corrected to 40°C}
\]
\[ R_t = \text{Measured Insulation Resistance in Megohms at Temperature } t \]
\[ K_t = \text{Insulation Resistance Temperature Coefficient at Temperature } t \]

Figure 3-1 Insulation Resistance Temperature Coefficient
Figure 3-2 shows an example of readings taken of actual temperatures and then corrected to a standard temperature.

![Graph showing readings corrected to a standard temperature](image)

**Figure 3-2 Readings Corrected to a Standard Temperature**

*Effects of Test Potential (Voltage) Magnitude*

The measurement of insulation resistance constitutes a potential test and must be restricted to a potential value no greater than the voltage rating of the winding and the basic insulation condition. This is particularly important in the case of small, low-voltage machines, or units that are unavoidably subjected to moisture. If the test potential is too high, the applied test potential may overstress the insulation. Insulation resistance tests are usually made at direct potentials of 500 to 5000 volts DC. The value of insulation resistance may decrease somewhat with an increase in applied potential; however, for insulation in good condition and
thoroughly dry, substantially the same insulation resistance will be obtained for any test potential up to the peak value of the rated operating potential.

Effect of Duration of Application of Test Potential: Polarization Index

The measured insulation resistance of a winding will normally increase with the duration of application of the direct test potential. The increase will usually be rapid when the potential is first applied. Then the readings gradually approach a fairly constant value as time elapses. The measured insulation resistance of a dry winding in good condition may continue to increase for hours with a constant test potential continuously applied. However, a fairly steady value is usually reached in 10 to 15 minutes. If the windings are wet or dirty, the steady value will usually be reached in one or two minutes after the test potential is applied. If equipment is available, the test potential should be applied for ten minutes or more to develop the dielectric absorption characteristic. The polarization index is a measure of the dielectric absorption.

The polarization index is the ratio of the ten minute test to the value of the one minute test (see Figure 3-3). It is calculated by dividing the ten minute reading by the one minute reading. Since it is a ratio, the two readings need not be corrected to a standard temperature. The polarization index is more useful in determining the immediate condition of insulation than a simple one minute "spot check". The minimum polarization index will depend on the specific equipment, however, a value of 2.0 or above usually indicates dry, clean insulation.

Effects of Existing Charge on Winding Resistance Measurements

Insulation resistance measurements will be in error if residual charges exist in the insulation. Therefore, before measuring the insulation resistance, windings must be completely discharged to the grounded machine frame. The grounding time should be a minimum of four times the charge or test time. The charge will be evident when the electrician performs the safety check to determine if the power is isolated. The four times rule should be observed when the charge is evident.
3.2.3 Measuring Insulation Resistance

Insulation resistance should be measured before a component is placed in service. If the component is out of service, the insulation resistance should be checked every six months, or earlier if the component is a critical spare or is in stand-by operation. If the component is operated continuously, the insulation resistance should be check annually. Motors and other electrical equipment become warm during operation. This usually prevent buildup of moisture in the windings. Equipment that is not operating is subject to condensation and moisture buildup.

The conditions for performing insulation resistance testing will vary. Whenever possible, the conditions below should be met.

Figure 3-3 Polarization Index
The insulation surface must be clean and dry if the measurement is to provide the information on the condition within the insulation as distinguished from surface condition.

The winding temperature should be at least a few degrees above the dew point to avoid condensation of moisture on the winding insulation. It is also important that, when comparing insulation resistance of machine windings, values be converted to a standard value.

It is not necessary that the machine be at a standstill when insulation resistance tests are made. It is often desirable to make insulation resistance measurements when rotating equipment is subject to centrifugal forces similar to those occurring in service. The test can be performed immediately after the machine is taken out of service and while it is still rotating.

Whenever machines are rotating during measurement of insulation resistance, precautions should be taken to avoid damage to equipment or injury to personnel. These precautions should include a tag out of the circuit breakers using a mechanical means to prevent accidental energizing of the equipment.

Test records of a given machine should indicate any special test conditions.

Whenever data is being trended, every effort should be made to conduct the test under the same conditions. This permits easier and more accurate comparison. However, it is not always possible to duplicate conditions, but if major deviations are recorded with the data, they can be factored into the review. Along with the test results, the following information should be recorded.

Motor Nameplate Data

Winding Temperature
Measuring Instruments

Direct measurement of insulation resistance may be made with the following instruments:

- Direct-indicating ohmmeter with self-contained hand or power-driven generator.
- Direct-indicating ohmmeter with self-contained battery.
- Direct-indicating ohmmeter with self-contained rectifier using an external alternating current supply.
- Resistance bridge with self-contained galvanometer and batteries.

Testing Guidelines

Generally two electricians carry out the one minute or the ten minute tests. Before performing the test, the motor data and past history can be reviewed to give an idea of what to expect and warn of past problems.

Next the applicable motor (or other electrical component) and related electrical equipment should be identified and completely disconnected and tagged from all power sources. Where possible, both disconnects and circuit breakers should be opened.

At this point a voltage tester should be used to test for live circuits and residual voltage. Any residual voltage should be discharged to ground before continuing the
test. When using the tester, leads should be attached to the appropriate terminal or ground using an alligator clip, so only one hand is required in the proximity of possible energized equipment.

The insulation resistance reading can be taken at a point closest to the component itself. The testers' reading with the leads shorted together should read zero. This serves as a check on the testers' accuracy.

Next, the ground lead is connected to the appropriate terminal or ground (frame of component). The other lead is placed in contact with each phase terminal. It is recommended that each phase be isolated and tested separately when feasible. Testing each phase individually gives a comparison between phases which is useful in evaluating the phase to phase insulation resistance.

When testing individual phases the neutral end of each phase winding should be disconnected and the phases not under test should be grounded. Another method of testing each phase separately is to use guard circuits on the phases not under test.

Tests may be made on the entire winding at one time, under certain conditions, such as when time is limited. However, this procedure is not preferred. One objection to testing all phases at a time is that only ground insulation is tested and no test is made of the phase-to-phase insulation. The phase-to-phase insulation is tested when one phase is tested at a time with other phases grounded.

The connection leads, brush rigging, cables, switches, capacitors, lightning arresters, and other external equipment may influence the insulation resistance test reading on a machine winding to a marked degree. Thus it is desirable to measure the insulation resistance of a winding exclusive of the external equipment of the machine. Often, though, the motor cables leading to the motor are left in the test circuit. If a problem is detected, the cables can be disconnected and each item tested individually to determine the cause.

The insulation resistance readings obtained are adjusted for the test method:

- Total Winding Tested - No Reading Adjustment
- Each Phase Tested/Others Grounded - Divide Reading By Two
Each reading is then corrected to a standard temperature for comparison against earlier readings.

Readings taken on a scheduled basis can be plotted for trending the winding’s insulation resistance. Trending of readings is more important than single readings. A significant drop in readings indicates failing insulation and can predict maintenance actions.

3.2.4 Minimum Insulation Resistance Value

Presently, the acceptable industry practice permits one megohm as the absolute minimum value of insulation resistance for any electrical equipment. For higher voltage equipment (greater than 500 volts), the IEEE standard 43-1974 recommends calculating the minimum value from:

\[ R_m = kV + 1 \]

where:

- \( R_m \) = Recommended Minimum Insulation Resistance (in Megohms at 40°C) of the Entire Machine Winding
- \( kV \) = Rated Machine Terminal to Terminal Potential (in rms Kilovolts)

Note that the IEEE recommended value is always a value larger than one megohm and increases for machines with higher terminal to terminal potentials. The actual complete winding insulation resistance to be used when comparing to the calculated value must be corrected to 40°C.

3.2.5 Interpretation of Results

Insulation resistance history of a given machine, made and kept under uniform conditions, is recognized as a useful way of monitoring the insulation condition. Figure 3-4 shows a typical form used to trend corrected insulation resistance values over a period of time. The following guidelines should be used when interpreting the results of insulation resistance tests.
Figure 3-4 Form for Trending Results Over Time
Steady drops in insulation resistance over a period of time is normal and can be used to help predict when the equipment may need service.

Investigate sudden drops in insulation resistance (refer to Figure 3-5 for examples of typical test results). These can be caused by an oil seal failure, internal fault, etc. If a sudden drop is noticed and the problem cannot immediately be determined, increase the frequency of testing. Do not allow the equipment to operate below the minimum acceptable level.

When the insulation resistance history is not available, recommended minimum values of the polarization index or of the one minute insulation resistance may be used to estimate the suitability of the winding for an over potential test or for operation. The one minute insulation resistance (corrected to 40°C) should be at least that of the recommended minimum insulation resistance value obtained from \( R_m = kV + 1 \).

It is recognized that it may be possible to operate machines with values less than the recommended minimum value; however, it is not normally considered good practice.

In some cases, special insulation material or designs, not injurious to the dielectric strength, will provide lower values. These special cases should be identified by the motor vendor.

When the end winding of a machine is treated with a semiconducting material for corona elimination purposes, the observed insulation resistance may be somewhat lower than that of a similar machine which is untreated.

The insulation resistance of one phase of a three-phase armature winding with the other two phases grounded is approximately twice that of the entire winding. Therefore, when the three phases are tested separately, the observed resistance of each phase should be divided by two to obtain a value which, after correction for
OIL-FREE MACHINE SHOWING CARBON DUST ACCUMULATION PLUS VARYING DEGREES OF DRYNESS

MOISTURE-FREE MACHINE

OIL-FREE, FAIRLY DRY MACHINE

OIL-FREE MACHINE EXPOSED TO EXCESSIVE MOISTURE

Figure 3-5 Example Test Results
temperature, may be compared with the recommended minimum value of insulation resistance for the complete winding.

If each phase is tested separately and guard circuits are used on the other two phases not under test, the observed resistance of each phase should be divided by three to obtain a value, which, after correction for temperature, may be compared with the recommended minimum value of insulation resistance for the complete winding.

For insulation in good condition, insulation resistance readings of 10 to 100 times the value of the recommended minimum value of insulation resistance \((R_m)\) are common.

In applications where the machine is vital it has been considered good practice to initiate reconditioning should the insulation resistance, having been well above the minimum value, drop appreciably to near that level.

Machines rated at 10,000 kVA and less, to be considered in suitable condition for operation or for over potential tests, should have either a value of the polarization index or a value of the insulation resistance (at 40°C) at least as large as the recommended minimum values.

Machines rated above 10,000 kVA should have both the polarization and the insulation resistance above the minimum recommended value.

3.3 Oil Analysis

3.3.1 General Discussion

Oil analysis is one of the key tools utilized in predictive maintenance to provide data about the condition of machinery. A comprehensive oil analysis program provides maintenance personnel with the ability to predict potential equipment failures thus
permitting proper scheduling and performance of the required service rather than having unscheduled and unplanned down times.

State-of-the-art oil analysis and diagnostic techniques are available to measure several different elements, wear metals and additives, as well as the sample contaminants and physical properties.

Oil analysis should determine both machine condition and lubricant condition. Lubricating oil may be used as a diagnostic medium because oil carries wear debris away from the wearing surfaces. Analysis of the wear debris can therefore provide important information about the condition of the internal parts of a machine or engine. On the other hand, the condition of the lubricant itself is important to know. Does the lubricant meet specifications? Is the viscosity correct? Is the oil contaminated with water, particulate or chemical compounds?

3.3.2 Additives

As a minimum, lubrication oils contain an antioxidant to retard oxidative attack and a rust inhibitor to protect iron-base metals. In addition, an antifoam agent and a metal deactivator may be present. Depending on the properties of the mineral oil base, other functional additives may be used to achieve the required performance characteristics.

Over extended periods of time, some additives may be consumed through absorption onto system materials or contaminants, deterioration by chemical reaction, thermal degradation, etc. This consumption may be wholly or partially offset by the routine addition of makeup oil. It is not unusual for lubrication oils to remain in service for periods between 15 and 20 years. In a lubrication system requiring relatively low makeup, oil properties should be monitored closely to ensure that any performance loss is identified. While it is possible to reinhibit an oil by mixing in an additive, this approach should be carefully considered and should only be taken after close consultation with the turbine oil supplier.

3.3.3 Contamination

Contaminants within the lube oil system may be generated internally or drawn externally into the system from the surrounding environment through entry at seals or vents. External contamination may include airborne dust, sand, coal particulates,
moisture, etc. Internally generated contaminants may consist of wear-metal particulates, which are constantly being produced in some degree, leaked coolant, and oil degradation products such as sludge.

Excessive or uncontrolled buildup of contaminants should alert maintenance personnel to identify the source, take corrective action, and determine whether oil purification equipment or system filters are properly functioning.

3.3.4 Physical Properties of Lubrication Oil

In-service monitoring of the condition of a lube oil should focus on the following properties:

- Anti-rust Protection
- Remaining Oil Life (oxidation Stability)
- Viscosity
- Total Acid Number
- Cleanliness
- Foaming Tendency
- Color/ Appearance
- Water Content
- Flash Point

Anti-Rust Protection

Within the turbine oil system, numerous ferrous metals require rusting protection. This protection is afforded in large part by the anti-rust additive present in the oil. New and used oils suitable for continued service must pass ASTM Method D 665-83 Procedure A, or D 3603-82. This is a dynamic test designed to evaluate the ability of lube turbine oils to prevent the rusting of ferrous components should water become mixed with the oil in service.

In this method, a cylindrical steel specimen is immersed in a glass beaker containing 300 ml of the test oil and 30 ml of distilled water at a temperature of 140°F (60°C).
The mixture is stirred throughout the test, which normally lasts 24 hours. Rusting of the steel specimen is determined by visual examination after test.

Remaining Oil Life

Remaining oil life is a measure of the remaining capability of oil to resist severe thermal/oxidative breakdown. Remaining useful oil life is strongly related to the remaining concentration of the antioxidant in the oil. The oxidation stability of new oils is generally measured by ASTM Method D 943-81. A 50-g sample of the test oil and 5 ml of water are placed in a small glass container containing a copper catalyst coil. The container is put into a metal oxidation bomb which is pressurized with oxygen to 90 psi (620 kPa), and then placed in a constant temperature bath at 302°F (150°C). The bomb is rotated at 100 rpm at an angle within the bath of 300° from horizontal. Oxygen pressure is monitored continuously during a run, and the test is terminated when the pressure drops more than 25 psi (172 kPa) below the maximum pressure. This event generally reflects accelerated oxidation of the test oil, and the test time elapsed before accelerated oxidation is a measure of the remaining oxidation life of the oil in service when compared with the RBOT data for the new oil.

Viscosity

Oil viscosity is a measure of resistance to flow. In practice, it is unusual to find that viscosity has changed due to thermal breakdown or oxidation. However, this property is useful as an indicator of the presence of viscosity modifying contaminants such as water or solvents, and for verification that the correct grade of oil is being used. ASTM Method D 445-83 is the common procedure for measurement of kinematic viscosity. With this technique, the time required for a volume of oil to flow under force of gravity through a calibrated glass capillary is measured. For accurate results, the glass viscometer tube must be in a precisely controlled constant temperature bath during the measurement. Kinematic viscosity, \( v \) is the ratio of absolute viscosity, \( \mu \), to density, \( \rho \).

Total Acid Number (TAN)

When a petroleum oil chemically oxidizes, small amounts of acidic products are formed. An increase in the TAN over that for the new oil is an indication of the extent of oxidation of the used oil. The TAN is determined by ASTM Method D 664-81,
D 974-80, or D 3339-80. To conduct the test, a weighed sample of the oil is dissolved in a solvent, and the solution is titrated with potassium hydroxide (KOH) solution to a predetermined endpoint. In D 664, the endpoint is indicated by electrodes in the solution which give a meter readout of the solution pH. In D 974-80, a color indicator is added to the test solution and the titration endpoint is visually observed by the solution color change. In both cases, the TAN is calculated from the amount of KOH required to reach the defined endpoint.

Cleanliness

Solid particulates can be generated internally or drawn into the lubrication system. They are of concern because they can accelerate wear of system mechanical components and can catalyze oxidation of the lubricant. Cleanliness is expressed in terms of the amount of particles for a given volume of oil. The three types of contamination analysis techniques are:

- Microscopic Particle Counting
- Automatic Particle Counting
- Gravimetric Analysis

Microscopic and automatic particle counting techniques express cleanliness in terms of the number of particles within a specified size range for a given volume of oil (particles/mL). Gravimetric analysis expresses cleanliness in terms of the weight of particles per given volume of oil (mg/L).

Foaming

Problems associated with excessive oil foaming may include oil pump inlet starvation and loss of capability to transfer heat away from mechanical components. Foaming tendency is frequently a consequence of soluble contamination or loss of the antifoam additive. Loss of the antifoam agent may be corrected by additive makeup, but only on the advice of the oil supplier. An excess of the additive may actually aggravate foam problems.

Laboratory evaluation of foaming tendency is made using ASTM Method D 892-74. A sample of the test oil is placed in a graduated cylinder. Air is blown at a constant rate through the sample held at a controlled temperature. After an airflow period of
5 minutes, the volume of foam generated is noted. A second foam reading is taken after a 10 minute settling period.

Color/Appearance

Visual observation of the color and appearance of the oil provides a rapid and inexpensive measure of its condition. A hazy appearance may be indicative of entrained water or particulates. A rapid darkening of the oil could be a consequence of excessive deterioration. (A slow, gradual darkening over a period of years is considered normal.) Although laboratory measurement of oil color is not normally performed, ASTM Method D 1500-82 is available for the determination of color on a relatively precise scale. This procedure employs a colorimeter with a light source and glass color standards. The test sample is placed in a glass jar, and its color compared against that of the glass standards.

Water Content

The presence of water in the lubricant can result in numerous performance problems. Water will promote sludging and additive loss and impair the lubricating ability of the oil, accelerate rusting, etc. Excess water in turbine oil can frequently be detected by visual observation. A more quantitative measure is provided by either ASTM Method D 95-83 or D 1744-M. The apparatus for Method D 95-83 which measures total H₂O is composed of a heated still, a reflux condenser, and a graduated glass trap. The oil sample is refluxed with a water-immiscible solvent which distills with the water. After condensing, water settles in the graduated trap, and the solvent overflows back to the still section. The test is complete when the volume of condensed water remains constant for a period of 5 minutes.

Flash Point

The usefulness of the flash point determination for a used oil is in the detection of volatile solvents that may have been inadvertently introduced into the oil system. Such an occurrence should also be indicated by a reduction in oil viscosity. A number of test methods for flash point determination are available, but ASTM Method D 92-78 is the most frequently used. The cup is filled with the test oil and heated at a specified rate dictated by the sample temperature. At intervals of temperature indicated by a thermometer in the sample, a small flame is passed over the surface of
the cup. The sample flash point is defined as that temperature at which a flash appears on the oil surface.

Categories of Elements

Some elements commonly present in lubricating oil could be categorized as wear metals, additives and contaminants. The most important wear metals from the point of view of the power industry are iron (Fe), copper (Cu), lead (Pb), and tin (Sn) for plain bearings and iron (Fe), chromium (Cr), nickel (Ni), and copper (Cu) for rolling element bearings.

Common Wear Elements and Additives

Various combinations of the elements listed below are often found in lubricating oils. A good familiarity with these elements and their sources is essential for effective utilization of oil analysis as a diagnostic tool. The following is a list of some commonly encountered wear elements and additives with an outline of their primary sources.

**Aluminum:** pistons, bearings, pump vanes, thrust washers, some blocks, pump bushings, housing, clutches impellers, rotors

**Chromium:** rings, bearings, liners, exhaust valves, rods, spools, gears, cylinder, shafts

**Copper:** bearings, thrust washers, bushings, oil additives as oleates, governors, discs, plates, pistons, shields, clutches

**Iron:** cylinders, crankshafts, valve train, clutches, pistons, rings, gears, bearings, liners, plates, blocks, camshafts, pumps, shift spools, cylinder bores, and rods

**Lead:** bearings, fuel additive as tetraethyl for octane improvement and antiwear/antiknock

**Magnesium:** lubricant additive, primarily phenate, improving TBN and stability, housing

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3-23
Moilybdenum: oil additive specifically for friction modification, thermal stability

Nickel: alloy, gear plating, valves and valve guides, ring lands, shafts, antifriction bearings

Silver: wrist pin bushings, EMD antifriction bearings, silver solder

Tin: bearings, piston plating, alloy of bronze with copper

Silicon: ingested dirt, gasket sealant, antifoam/surfactant, antifreeze additive Contaminant exists as silica.

Barium: lubricant additive, detergent

Sodium: lubricant alkalinity improver, valve stem filler, antifreeze, salt, dirt

Potassium: antifreeze additive

Boron: borates, dispersants, some antifreeze

Zinc: antiwear, friction modifier, existing as dialkyl, diamyl, or diaryl groups of dithiophosphate

Typical Wear Metal Trends

Predictive Maintenance using oil analysis is based on establishing wear metal trends. The relative motion of metallic parts in an oil-wetted system is always accompanied by friction. Consequently, some of the metallic surfaces are worn, and the particles thus created are found in the lubricant. Under normal operating conditions, wear proceeds at a slow steady rate. Abnormal conditions cause an increase in the wear rate. It is the requirement of the oil analysis instrumentation to determine the wear metal elements present and in what concentration; in other words, to identify and quantify.

Oil analysis is, therefore, a scientific predictive maintenance technique applicable to closed loop lubricant systems. Spectrometers are able to determine which wear metals are present in a lubricant and in what concentration. This information allows
maintenance personnel to make a determination on the operational status of the system. For example, an increase in nickel and silver in certain types of diesels is indicative of bearing wear. If detected early, a relatively simple bearing replacement can be made, rather than a $40,000-$60,000 overhaul and crankshaft replacement. An increase in the amount of silica in conjunction with a corresponding increase in iron, aluminum and chromium is usually caused by dirt. Air filter replacement and an oil change may be the only maintenance required. An increase of silicon may mean the oil was topped off with one containing a silicon-based, anti-foaming agent, and no maintenance action is required. The same trend without the increase in silica could be indicative of piston wear. The more information available for diagnosis, the more effective the evaluation of wear trends.

How the Spectrometer Works

Figure 3-6 illustrates the block diagram of a spectrometer. A sample of the oil is heated up to 12,000 degrees Celsius. Each chemical element when heated becomes excited. This excitation causes the elements to emit unique light characteristics. Let's say that the light barium emits is a unique green, and the light emitted by calcium is a unique red. This obvious difference is perceived, detected, and calculated by the spectrometer. However, most chemical elements are not seen as easily as barium and calcium and are also not visible to the human eye because of either their low concentrations or the light emitted is only in the ultraviolet region.

![Spectrometric System Block Diagram](image)

Light carried by a fiber optic cable is focused on the entrance slit by means of a lens to maximize the amount of light onto the entrance slit. The entrance slit forms an image
which is focused onto the diffraction grating. It is here that the light is separated or
diffracted into its component wavelengths. As the light strikes the grating, it is
reflected back toward the focal curve. The diffraction grating causes the angle of
reflection to vary with the wavelength of the light, thus separating the light into
discrete spectral lines. Exit slits are placed at exact locations along the focal curve to
allow passage of light of those specific wavelengths for the elements which are to be
measured. Photomultiplier tubes (PMTs) are precisely positioned behind the exit slits
to measure the light passing through the slits. The Optical System may be considered
to end at the exit slit and the Readout System to begin with the photomultiplier tubes,
although the photomultiplier tubes are physically connected to the optical frame.

Spectrometric oil analysis, as it is routinely applied by laboratories, is insensitive to
particles larger than a few micrometers. Magnetic plugs and chip detectors sense
particles only after an advanced failure mode is in progress. Ferrographic analysis
bridges the gap between these two detection methods.

3.3.5 Ferrography

Ferrography is a technique for separating metal particles, contaminants, and other
particulates from liquid for the purpose of monitoring, trending, and diagnosing of
equipment wear.

The technology includes the measurement and analysis of particles quantitatively and
qualitatively. These particles range in size from 1-250 micrometers and generally
cannot be seen with the naked eye. A high powered bichromatic microscope is used
to view the particles, using magnifications of 100x, 500x, and 800x. As applied to
machine wear analysis, ferrography is a proven method of determining machine
condition and reducing malfunction, based on the analysis of the particles.

Quantitative Wear Particle Analysis by Ferrography

Wear Particle Size and Concentration

Every oil lubricated wear surface generates particles. The size and shape of particles
generated in a normal operating machine can be easily established. When a machine
enters a severe wear mode, then particles increase in size, in quantity, or both. During
benign wear, a machine will generate particles up to 10 μm in major dimension. When
abnormal wear occurs, the particles often increase in size to 20 μm, 50 μm, and larger, and the wear particle concentration can increase by an order of magnitude. The indication of trouble is not subtle, it is obvious. As wear progresses from normal to advanced failure, both the size of the wear particles and the concentration of the wear particles increase.

How The Particles Are Separated

An oil sample is caused to flow over a glass or plastic substrate in the presence of a strong magnetic field gradient which pulls the particles to the glass. After deposition, the oil is washed away with a solvent leaving the particles clean, aligned, and fixed to the substrate. The resulting ferrogram is a permanent record.

How The Direct Reading (DR) Ferrograph Works

The direct reading (DR) ferrograph was designed to measure both an increase in size as well as an increase in concentration of wear particles. Sample fluid is siphoned through a precipitator tube where a magnet assembly located beneath the tube precipitates the wear particles according to size. The large particles are deposited first, then the smaller ones further down the tube. Two light beams pass through the precipitator tube. The first beam is located near the tube's entry where the larger (L) particles (> 5 μm) are deposited, and the second beam passes through the tube where the smaller (S) particles (1 to 2 μm) are deposited.

Microprocessor electronics cause the readings to be zero when a sample first enters the precipitator tube. As particles deposit in the precipitator tube, the L and S readings increase. After a known volume of sample (usually 1 mL) passes through the precipitator tube, the L and S reading are recorded.

Using the DR Ferrograph a quantitative baseline (a statistical mean) should be established for each generic type of machine. When the DR readings increase significantly, usually by 2 standard deviations, a ferrogram should be made. The ferrogram provides a display of particles and it is the shape, color, quantity, size, and composition of the particles which provide insight into the machine condition. Ferrograms made during normal operation should be catalogued using photographs of principal particle types. This photography provides a benchmark of benign wear for the machine in question. When a machine starts to fail, the particles generated are
usually vastly different from normal. The abnormal particles often point to the machine component in trouble and reveal the mode and severity of wear.

**Equilibrium Wear Particle Concentration**

Experience has shown that the wear particle concentration, as measured by the DR ferrograph, will be more or less the same from sample to sample when taken from the same machine after that machine has gone through break-in as long as the operating conditions for that machine are approximately the same from sample to sample.

As the oil flows through a typical machine, particles are generated by the wearing surfaces within the machine and particles are lost by the following mechanisms:

- Filtration
- Settling
- Impaction and Adhesion (Sticking to Solid Surfaces)
- Comminution (the Grinding Up of Particles)
- Dissolution (Oxidation or other Chemical Attack)
- Magnetic Separation (as Occurs in Electric Machinery)

After a period of time, depending upon the oil flow rate and the collection efficiency of the various particle capture mechanisms, the particle generation rate will be balanced by the particle loss rate. When this occurs, the wear particle concentration is said to be in dynamic equilibrium. DR readings will now remain constant as long as nothing disturbs the wear particle generation rate or the wear particle loss rate.

**Analytical Ferrography**

Analytical ferrography is the process of evaluating the ferrogram (i.e., the wear particles magnetically precipitated from the oil sample). The process entails the preparation and detailed visual analysis to determine the nature of equipment wear and individual parts providing patterns of incipient or catastrophic failure.

Analytical ferrography is readily applicable to elemental analysis of particles beyond the size range of spectrometers. Analytical ferrography separates the ferrous particles by size and they align themselves into tight chains of particles. The non-ferrous particles, contamination, and other weak
magnetic particles do not form strings, but form a somewhat random pattern on the ferrogram. This different behavior makes it instantly clear which particles are ferrous and which are not. Once the particles in question are located, a ferrogram heating procedure can be used to quickly determine if the ferrous particles are cast iron, low alloy steel, or stainless steel.

Simple color and/or chemical tests are available to quickly identify all the non-ferrous metals except for silver and chrome. Where these two elements are suspected, the particles can be analyzed using an X-ray analyzer attached to a scanning electron microscope (SEM). When a SEM is used, carbon substrates may be used to obviate the need to coat and to eliminate the sometimes confusing interference of the glass. Of course, the SEM may be more routinely used for material identification when it is convenient.

Analytical ferrography is designed to identify the nature and sources of wear particles and other contaminants utilizing logical wear mode association. The following is a listing of various types of wear metals and contaminants identifiable through the analytical ferrography technique.

3.4 Vibration Analysis

3.4.1 Introduction

Vibration is an operating characteristic of all rotating and reciprocating machinery. Vibration forms a pattern based upon the individual design and operational characteristics of the equipment. Understanding the causes of vibration and being able to "read" the associated pattern provides maintenance personnel with a method of monitoring overall equipment condition. This Section addresses the basic principles of vibration and presents typical vibration problems as they relate to rotating equipment.

3.4.2 Vibration

Vibration is the oscillation of a machine or part with respect to a fixed reference point. A simple way to visualize vibration is to follow the motion of a weight suspended on the end of a spring, as shown in Figure 5-7. With the weight alone, there is no vibration. However, when a force is applied to the weight to cause it to move, and the force is re-applied on each oscillation, a continuous, cyclic motion results. This cyclic
motion can be represented relative to time by a sine wave. The spring displacement is the amplitude of the wave. The time required to complete one cycle is the period of the oscillation. Both the amplitude and period are dependent upon the spring stiffness and the amount of weight.

![Diagram of a simple spring-mass system](image)

**Figure 3-7** Mechanics of Vibration

Machinery vibrations are also cyclic and can be represented by sine waves. The machine's prime mover provides the continuously re-applied driving force. The machine's overall weight and the relative stiffness of construction influence its vibration pattern or "signature". The actual vibration signature is a complex function of many cyclic waves. However, these waves can be separated by filters and analyzed individually.

### 3.4.3 Vibration Terminology

There are several terms common to vibration monitoring and analysis that must be defined before vibration can be fully understood.

- **Vibration Amplitude**  Vibration amplitude is the maximum displacement from a fixed or neutral position. Peak-to-peak amplitude is the distance between the maximum positive displacement and the maximum negative displacement. Vibration amplitude is usually expressed in mils (1 mil = 0.001 inch).
Vibration Frequency  Vibration frequency is the number of complete cycles or oscillations occurring in a given time period. Frequency is the reciprocal of the vibration period. Vibration frequencies are usually expressed in cycles per minute (cpm) or cycles per second (Hertz).

Hertz (Hz)  Hertz is a unit of measurement for vibration frequency. One Hz equals one full vibration cycle or oscillation per second.

Vibration Displacement  Vibration displacement is the distance a part travels, usually expressed in mils peak-to-peak.

Velocity  Velocity is the time rate of change of displacement, usually expressed in in/sec.

Acceleration  Acceleration is the time rate of change of velocity, usually expressed in in/sec². If velocity is constant (peak-to-peak displacement not changing), acceleration is zero.

Phase  Vibration phase expresses the cyclic relationship between two vibration signals. Phase is expressed in degrees, with 360 degrees representing a full cycle. If one signal reaches its full amplitude at the same time as the second signal, the two signals are said to be "in phase" or 0 degrees out of phase.

Vibration amplitude (displacement), velocity and acceleration can all be measured and used to determine the amount or severity of a machine's vibration. Actually, all three are directly related. For example, if vibration peak-to-peak displacement and frequency are known, the peak velocity can be calculated.

Unfortunately, it cannot be said, in general, that one measurement is "better" than the other. The amount of energy that is dissipated or absorbed by the machine causing damage is proportional to all three parameters: displacement, velocity, and acceleration. They all must be considered. It is important to realize that if one observed a very high acceleration at a very high frequency, chances are reasonably good that the amount of displacement associated with that vibration is quite low. Conversely, at very low frequencies, if one were to observe a relatively low acceleration, the displacement could be incredibly high. It is important to understand
the relationship between the different measurements being made. Most manufacturers give maximum acceptable vibration limits in terms of velocity (in/sec) and peak-to-peak displacement.

3.4.4 Vibration Sensors

There are many types of instruments used to measure vibration but regardless of the type of instrument used to measure vibration, the heart of the instrument is the sensor. A vibration sensor converts mechanical vibration into an electrical output signal. The three most common vibration sensors are velocity pick-ups, accelerometers and proximity probes.

Velocity pick-ups and accelerometers are contact sensors, with the transducer physically contacting the equipment part being monitored. Most contact sensors are mounted directly on the casing or bearing housing of the machine being monitored. Velocity pick-ups and accelerometers measure the relative motion between the point of contact and free space.

Proximity probes are non-contact sensors. They measure the relative motion between the machine part being monitored and a fixed reference. Proximity probes are usually mounted through a bearing collar, sleeve or a specially designed housing.

A velocity pick-up normally consists of a transducer having a cylindrical coil mounted to the inside of a casing. Within the coil is a spring-suspended magnet. The magnet is separated from the coil by a damping fluid (silicone oil). The transducer casing is installed directly onto the machine. Casing vibration forces the cylindrical coil to pass back and forth over the semi-stationary magnet. The relative motion between the coil and the magnet generates a voltage proportional to the vibration.

An accelerometer usually consists of a transducer containing a piezoelectric crystal mounted next to a small mass. The piezoelectric crystal produces an electric charge when subjected to pressure or stress due to vibration. As the transducer vibrates, the force of gravity causes the mass to exert pressure on the crystal. The crystal generates an electrical signal in proportion to the vibration.

A proximity probe normally consists of a transducer which measures the displacement or position of a conductive (usually metal) surface relative to its mounted location.
This type of transducer operates on the eddy current principle. The proximity probe contains an iron core surrounded by a cylindrical coil. A high frequency AC current is passed through the coil and generates an electric field. This electric field passes directly through the probe tip. When a conductive surface (rotor or shaft) is placed near the field, some of the energy is absorbed. Therefore, the return voltage decreases as the relative distance is reduced. A meter measures the difference between the output and return voltages. This difference is proportional to the displacement between the probe tip and the conductive surface.

3.4.5 Sensor Applications

Each type of vibration sensor has inherent advantages and disadvantages. Velocity pick-ups are very accurate for monitoring vibrations between 600 cpm and 120,000 cpm (10-2000 Hz). They have rugged transducers and remain accurate over a wide range of temperatures. Velocity pick-ups do not require an outside power source because the voltage is self-generated. They can be permanently mounted or handheld. Velocity pick-ups are particularly well suited for anti-friction bearings because there is little damping between the shaft vibration and the bearing housing.

Velocity pick-ups also have several disadvantages. Their sensitivity and response can degrade over time due to changes in the internal damping fluid (oil). Since the viscosity of oil changes with temperature, the damping characteristics of the pick-up also change, causing slight variations in vibration readings. Velocity pick-ups are also physically large and heavy, limiting their use to relatively large equipment.

Accelerometers are very accurate for monitoring vibrations above 120,000 cpm (2000 Hz). These high frequency vibrations are usually caused by defective anti-friction bearings, gear boxes, or other high speed machine parts. Accelerometers are small, lightweight and easy to install. They are also very useful for monitoring vibrations in high temperature areas. Other key advantages include a wide frequency range and ruggedness. Supported by the associated electronics, accelerometers can measure acceleration, velocity and displacement. Accelerometers are usually more expensive than velocity pick-ups. Also, some types of accelerometers have internal electronic components that are sensitive to shock.

Proximity probes are ideal for monitoring the displacement between a shaft and sleeve bearing. They are not affected by oil dampening within the bearing. Proximity probes
can also detect axial rotor position and shaft misalignment. Many proximity probes can withstand temperatures up to 250 °F.

Proximity probe installations normally have two probes, mounted at 45° angles from vertical, as shown in Figure 3-8. This probe mounting arrangement provides more accurate measure of the vibration in each plane. Proximity probes usually require a signal conditioner to provide output signals proportional to the gap distances. Normal probe output is approximately 200 mV/mil.

3.4.6 Vibration Monitoring vs. Analysis

Vibration monitoring is the measuring of machinery vibration. It may be performed on a regular basis or at random time intervals. Vibration monitoring equipment can be hand-held or permanently installed, and usually includes displays or printouts.

Vibration analysis is the separation and examination of vibration signature components. That is, the separation and evaluation of the vibration values at different frequencies.

![Figure 3-8 Proximity Probe/Shaft Arrangement](image)
Vibration analysis equipment is used to diagnose problems found during vibration monitoring. Vibration analysis equipment includes spectrum analyzers and computers.

**Vibration Monitors**

Machinery vibration can be monitored at periodic intervals or continuously. Periodic monitoring is usually performed using a battery-powered, hand-held vibration meter. Continuous monitoring is accomplished using a permanently installed monitoring system.

Portable vibration meters accept vibration signals from contact and non-contact type sensors. The sensor may be hand-held and provided with the meter, or permanently installed. Once measured, vibration level is displayed on a scaled meter or digital readout. Vibration units may be displacement, velocity or acceleration, depending on the capability of the meter. Many vibration meters have a built-in printer or external connection for a plotter. The more advanced meters have integral spectrum analyzers for plotting vibration displacement in relation to frequency.

Many periodic vibration monitoring programs include manual data collection, logging and trending. This type of program is effective, but labor intensive. To reduce the manpower investment, inexpensive computer boards are currently available for installation into a personal computer (PC). Vibration data is collected and stored in a portable monitor, then transferred to the PC. The PC then organizes the data and allows easier analysis and trending.

Continuous vibration monitoring systems use permanently installed equipment sensors, mounting hardware, cables and monitors. These systems usually have alarms to alert personnel of excessive vibration, and trips to shut down the equipment if a dangerous level of vibration is sensed.

**Vibration Analyzers**

Common types of vibration analysis equipment include spectrum analyzers and computers. The spectrum analyzer is probably the most common. It determines the relationship between vibration amplitude and frequency, which is essential information for determining the cause of excessive vibration.
A spectrum analyzer converts the time-dependent (time-domain) vibration amplitude input to a frequency-dependent (frequency-domain) output. Within the time-domain input, the various vibration signal components are separated by time. The analyzer separates these signal components and displays them on an amplitude-vs.-frequency plot.

Over the past few years, the use of computers for vibration analysis has become more and more common. The associated computer hardware and software has dropped significantly in price, making computer analysis a viable alternative to using conventional spectrum analyzers. While computer vibration analysis provides all the benefit of a conventional spectrum analyzer, it can also automatically identify the cause of excessive vibration. Another advantage of computer analysis is the ability to store vibration historical data on diskette, and easily trend the data over time.

3.4.7 Determining Vibration Severity

Vibration severity is normally determined by the limits set by the equipment manufacturer. In the absence of manufacturer's guidelines, vibration severity can be determined using the guidelines contained on a general vibration severity chart, like the one shown in Figure 3-9. This type of chart shows the relationship between machine condition and vibration frequency, velocity and displacement. Some severity charts also show acceleration.

To use a vibration severity chart, locate the position on the vibration frequency axis corresponding to the measured vibration frequency. Follow the line down until it crosses the line corresponding to the measured vibration amplitude or velocity (whichever is known). The labeled region surrounding the intersection of these two lines describes the overall condition of the machine.

Some vibration severity charts are based on overall vibration levels. This means the measured vibration has not been separated into component frequencies. Rather than a vibration frequency axis, these charts have an axis for shaft rpm. Use of these charts is similar to that described above.

While general charts and manufacturer's data can be used to determine vibration severity, it should be recognized that a more appropriate measure of severity is
change. That is, has the vibration gotten worse over time? It is not uncommon for a particular piece of equipment to exhibit what would normally be considered excessive vibration, but when compared to historical data is seen to have been operating satisfactorily for years without any vibration increase. An accurate and well-documented record of a specific machine's operating history is the most valuable source of vibration severity standards.

Figure 3-9  Vibration Severity Chart
3.4.8 Causes of Vibration

There are many causes of machinery vibration. Several of the most likely include:

- Unbalance of Rotating Parts
- Bearing Wear
- Shaft Misalignment
- Oil Whip
- Mechanical Looseness
- Rubbing
- Worn/Damaged Parts
- Hydraulic or Electro-Magnetic Forces

Each of the above problems can alter a machine's vibration signature. Analyzing the signature changes helps pinpoint the cause and relative severity of the vibration.

The vibration signature of a machine is the sum of all the individual vibration components (i.e. misalignment, bearing wear, shaft run out, etc.). When the amplitude of the various vibration components, relative to frequency, is known, the cause of excessive vibration can usually be pin-pointed.

To aid in identifying the cause of excessive vibration, troubleshooting guides are available and should be used. A typical vibration troubleshooting guide is shown in Figure 3-10. This guide shows possible equipment vibration causes and describes the associated characteristics.

Unbalance is a very common cause of machinery vibration. The vibration signature for an unbalanced condition will show high vibration amplitude in the radial direction, at a frequency corresponding to shaft rpm.

Another common cause of excessive vibration is misalignment. The vibration signature for a machine with misalignment will show high vibration amplitude in the axial direction, usually (but not always) at a frequency corresponding to shaft rpm.
3.5 Acoustic Leak Monitoring

3.5.1 Introduction

Acoustic leak detection systems are automated continuous monitoring tools that help the operator detect incipient leakage conditions. Because acoustic monitors can filter background noise, they are more sensitive to small leaks than the human ear, and can detect small leaks earlier than conventional techniques. They may also identify the section where a leak is located.

3.5.2 Acoustic Leak Monitoring Terminology

The following list contains the fundamental terminology and definitions associated with acoustic leak detection.

- **Acoustic(s)** Acoustics in the broadest sense refers to the generation, transmission, and sensing of mechanical vibrations. Specifically, acoustics refers to pressure waves that are borne in gases and liquids.
Acoustic Emission This term refers to the generation of a transient mechanical vibration by an active defect in a structure or material. It is widely applied to any mechanical disturbance that exists in a structure.

Attenuation When mechanical energy propagates in a material, some energy is lost to the material. The energy loss causes a decrease in the signal and is referred to as attenuation. Many mechanisms contribute to attenuation in all materials; gases, liquids, and solids.

Combustion Roar The combustion process produces an acoustic signal referred to as combustion roar. It is generally contained in frequencies below 500 Hertz.

Continuous Signal (Emission) A leak signal produces a continuous random signal that appears as "noise".

Cutoff Frequencies These frequencies are the points where the signal level is reduced by 3 decibels (dB) (0.707) of the pass band of the filter. There is a high cutoff frequency which corresponds to the low-pass filter stage and a low cutoff frequency which corresponds to a high-pass filter.

dB Because of the wide range of signal amplitudes, logarithmic scaling is used in units in decibels (dB). A decibel is defined as ten times the logarithm of a power ratio. Since power is a function of the square of the signal amplitude, $A$, dB can be expressed as:

$$ dB = 10 \log \frac{A_1^2}{A_2^2} $$

Filter The filter is an electrical unit that is used to select the range of frequencies to be processed:

- **Low-pass Filter** Limits the signal to frequencies below its cutoff frequency to eliminate high frequency noise.
- **High-pass Filter** Limit signal to frequencies above its cutoff frequency to eliminate low frequency noise and DC drifts.
- **Band-pass Filters** Combination of high-pass and low-pass filters that pass signals between the low and high cutoff frequencies.

Gain The amplification of an electrical signal. It is expressed in dB of the voltage output relative to the voltage input.

Leak A leak is the flow of material across a pressure boundary due to a fault or breach of the boundary.
Leak Rate The leak rate generally refers to either the mass flow or volume flow. For given upstream and downstream conditions, the leak rate is dependent on the leak size.

Leak Size The leak size is the physical size of the hole in the pressure boundary.

Noise Noise is generally any signal that is either present in the acoustic signal or introduced by the electronics that is not part of the desired signal and which degrades the accuracy of the measurements.

Piezoelectric Effect Piezoelectricity is a property of materials that causes a charge to be developed across the material when it is mechanically deformed. Piezoelectric material also exhibits the reverse effect; when a charge is applied to the material, it mechanically deforms.

Preamplifier An amplifier is used immediately after the transducer. The purpose of the preamplifier is to buffer the transducer, supply some gain, and drive the signal through the transmission line.

Probe The probe refers to the waveguide assembly from the mouth of the waveguide to the output from the transducer.

Sensors The sensors are piezoelectric type, individually selected, according to the background noise in the pipe. They are available over a wide range of operating frequencies. Before installing the system, the background noise characteristics at different points on the piping system must be monitored and the sensors selected to limit the frequency range over which the acoustic emissions are detected.

Signal Signal refers to the actual time-varying parameter associated with the quantity of interest.

Signal Level Signal level refers to the amplitude of the signal (i.e., its strength). The most common measure of signal level is the rms value which is the root-mean-squared value of the signal.

Signal Conditioning Unit This unit is located in the instrument rack of the acoustic leak detection system. It receives the signal from the preamplifier and adds additional gain and filtering. The rms signal level is then calculated and compared to thresholds for the alarm functions. The unit outputs the rms signal level alarm status to a computer and/or display and recorder instruments.

Transducer The transducer is the unit that transforms the mechanical signal to the electrical signal. Also referred to as the sensor.
Waveguide In acoustic leak detection, the waveguide is the tube used to transmit the acoustic signal from the boiler to the face of the transducer. In acoustic emission systems, a waveguide is a slender rod. One end contacts the face of the transducer and the opposite end contacts the structure under test. In both cases, the waveguides are used to couple the signal from a harsh environment to the sensitive transducer.

3.5.3 Acoustic Leak Detection Basics

Wave Propagation

- Wave propagation is the phenomenon by which a localized disturbance spreads throughout a medium.
- Examples include the ripples that spread on the surface when a rock is tossed in a pond, the transmission of sound through air, radio waves, and seismic tremors in the earth. Therefore, wave propagation is common to many scientific fields.
- Elastic wave propagation is the transmission of mechanical disturbances in gases, liquids, and solids.

Sources of Acoustic Emission

- Internal Sources
  - Dislocations
  - Subcritical Crack Growth
  - Ductile Tearing
  - Fatigue Crack Growth
  - Stress Corrosion Cracking
- External Sources
  - Leaks
  - Scale Cracking
  - Rubbing
  - Loose Parts

Detecting the Presence of a Leak

- Leak detection is most often established by the rms signal from a sensor exceeding a preset threshold value.
The selection of the threshold value is based on several factors.

In practice, threshold values change as the operating environment and background noise change.

Preset time delays are often used to avoid spurious alarm indication.

The reduction of the rms signal output below a preset threshold value can also provide useful information.

Leak verification should always be accomplished when feasible. Techniques include visual inspection, water make-up rate, and plant maneuvers.

Identifying the Location of a Leak

The accuracy to which the location of a leak can be determined is based on component geometry. Simple geometries such as a straight line of piping lead to more accurate results than in more complicated component geometries such as a boiler. Leak signals are generally recorded by more than one sensor. Accurate leak location requires the leak to be located within the sensor array.

There are four general methods currently used to determine the location of a leak. These methods vary in complexity and accuracy. For most utility applications, knowing the general area (within one-half the separation distance between sensors) of a leak is sufficient. These methods are:

- Zone Location Method
- Signal Amplitude Measurement Method
- Signal Time Difference Method
- Signal Cross-correlation Method

Use of Waveguides/Soundtubes

A waveguide is a device that couples acoustic energy from a structure to a remotely mounted sensor. Remote mounting is most often required as a result of excessive structure temperatures or inaccessibility. It is usually a metallic rod or tube of appropriate shape secured or welded to the structure at one end with the sensor mounted at the other end. The waveguide introduces another interface between the structure and the sensor that will distort and attenuate the acoustic signal. Waveguides must be carefully shaped and mounted to ensure continuity in wave transmission to the sensor with acceptably low attenuation. If acoustic waveguides are used when source location is being performed, the extra time delay in the waveguide must be accounted for in the source location determination.
3.5.4 Typical System Description

An acoustic boiler leak detection system is composed of several components as shown in Figure 3-11. A sensor, or microphone, is mounted to the boiler wall by a tube that acts as a waveguide for the sound. The waveguide is generally curved to remove the sensor from direct radiant heat and to allow an air purge or mechanical rodding through the waveguide.

The sensor connects to a local preamplifier, which filters and amplifies the signal for transmission to the signal processing unit located in the control room. One signal processing unit handles multiple sensors/signals. Additional amplification and filtering of a signal is provided to calculate the rms voltage. This analog signal is compared to a threshold level for each channel. An alarm alerts the operator when the signal exceeds the threshold value, which is preset during initial calibration for normal background noise.

The signal conditioner unit requires that the threshold be exceeded for a maximum time before alarming. This eliminates nuisance alarms during sootblowing or other temporary occurrences. Alternatively, the alarm function can be connected to the sootblower control panel to inhibit the alarm during sootblowing. A low threshold alarm can also be incorporated into the signal conditioner to indicate a plugged waveguide or damaged sensor.

In addition to alarms, the system output can be continuously recorded on strip charts or stored by a data logger or computer. Data retrieval from these devices is a convenient method of monitoring the progress of a leak.

Several channels are required to monitor an entire boiler. Figure 5-12 illustrates one example of the sensor locations on a boiler. The total number of sensors and their actual locations can be jointly determined by the manufacturer and the utility. A general guideline is to assume that a sensor has a 30 foot range of detection.

Sensitivity and Sensor Location

The sensitivity of the sensor depends on three factors: sound radiated from the leak, attenuation of sound between the leak and the sensor, and background noise. Leak noise is broad-band, ranging from below 1 kHz to 2 MHz. Because of the low-frequency background noise and the greater attenuation of high frequencies, most gas borne systems operate in the range of 1-25 kHz. Operators determine leak location and growth by comparing the response of several detectors. Because sound energy or intensity (measured in decibels) diminishes as it travels from the source, there is a trade-off between minimum detectable leak size and sensor location.

To determine optimal monitoring frequency bands, threshold values, and sensor locations, EPRI is sponsoring studies to investigate acoustic attenuation, leak signatures, and background noise levels in power plant equipment.
Figure 3-11 Acoustic Leak Detection System
Figure 3-12 Location of Acoustic Leak Detection Sensors
3.5.5 Principles of Operation (Boiler Tube Leak Application)

The sound generated by the expanding steam jet determines the signal-to-noise ratio at the detector. The flow turbulence of leaking steam generates a broadband sound, which is relatively strong within the frequency range of 100 Hz to 100 kHz and peaks in the range of 1 to 5 kHz. Amplitude of the sound increases with leak size. A typical sensor has a frequency response in the 1 to 10 kHz range.

Several phenomena however, may interfere with the signal. As the sound propagates, its signal strength decreases with distance from the source; sound intensity is inversely proportional to the square of the distance from the source. As a result, acoustic signal strength attenuates, that is, it falls off rapidly over distance. Absorption and scattering also diminish acoustic signals. When a sound wave passes through furnace gases, the wave increases the motion of the gas molecules and some of the sound energy is absorbed. Suspended particles, such as fly ash, further diminish acoustic energy by scattering the sound wave.

Figure 3-13 is produced by a tube leak with combustion background noise. While background noise dominates at lower frequencies, there is a significant increase in signal amplitude between 1-5 kHz due to leak noise. Electronic filters are used to eliminate frequencies below 1 kHz and above 5 kHz. A leak is indicated by a factor of two root mean square (rms) signal increase over background in the 1-5 kHz frequency band.

![Figure 3-13 Acoustic Signal](image)
Background noise, mainly from combustion, also masks the leak signal. Combustion roar is a broadband signal extending up to several kilohertz with a peak amplitude near 200 Hz. Its intensity increases with boiler load, and it varies significantly with boiler region and type. For example, cyclone-fired boilers have higher ambient noise than pulverized-coal fired or oil-fired boilers.

Sootblowers also generate background noise. Because sootblowers produce strong signals, leak detection system alarms may be inhibited during sootblower operation. Some operators, however, leave the system in operation during the sootblowing cycle to quickly detect sootblower valve functions, such as sootblowers that stick in the inserted position.

A leak is detectable when the acoustic signal from the leak at the detector is sufficiently higher than the background noise. Although background noise predominates at the lower frequencies, acoustic pressure from leaks is significantly higher at the higher frequencies.

3.5.6 Other Applications

Acoustic leak detection systems are effective in detecting additional plant problems. They have detected and located pinhole leaks during boiler hydrostatic testing, which may prevent future shutdowns.

These detection systems have also effectively detected steam header leaks in the boiler penthouse region. Detection of such leaks can significantly enhance safety when continued operation is required until the next scheduled outage. Using an acoustic leak detection system to detect steam header leaks is standard practice in some U.S. utilities.

High and low-pressure feedwater heater leaks produce detectable structure-borne and fluid-borne acoustic signals. Structural signals in the range of 1 kHz are monitored using a sensor coupled to the tube sheet with a solid 1/4 inch waveguide. Fluid signals in the range of 5-15 kHz are sensed through the channel side drain line. Feedwater system valves cause large changes in background noise. Comparing the signals of adjacent feedwater heater sensors allows tube leaks to be discriminated from the valve throttling noise. The different sensors and filtering needed for feedwater monitoring are easily added to a boiler tube leak detection system.

By monitoring sootblowing operations with a boiler leak detection system, operators can verify proper soot-blower operation. Improper sootblower operation - damaged nozzles, nozzle misalignment, or failure of the sootblower to retract - can erode boiler response. A subsequent steady decrease results from greater attenuation as the probe extends farther into the boiler. Full extension gives a minimum acoustic signal. When the sootblower is retracted, the signal increases until it returns to "normal" background level. Changes in the normal sootblower signature indicate a malfunction.
Feedwater Heater Leak Detection

Feedwater heater tube leaks are caused by a variety of factors, including fretting, corrosion at tube bends and supports, stress corrosion cracking, and local high-velocity erosion. Once a leak has occurred, steam washing rapidly erodes the surrounding tubes. Failed tubes must then be plugged, reducing plant efficiency. Acoustic monitoring can limit heater damage by providing early detection of leaks to operators.

Pipe Crack and Leak Detection

Several catastrophic failures of high energy piping systems have alerted utilities to the serious problem piping poses for plant life extension. Subsequent inspections of aging plants have revealed substantial damage in feedwater piping, high-temperature steam lines, and boiler headers. Although frequent comprehensive inspection is one means of guarding against failure, the time and costs involved often make this method impractical. Moreover, methods for analyzing a component’s life are inadequate to precisely determine time of failure. Acoustic monitoring of structure-borne noise caused by pinhole leaks can help ensure the integrity of critical plant components.

Boiler Headers

Under project RP734-6, EPRI acoustically monitored final superheat outlet headers of boilers that had serious creep swelling and cracking in the tube-hole ligament area (report CS-5264). The sensors detected acoustic bursts emitted by crack growth during both hydrostatic testing and full-load operation. They also located high-amplitude events during steam-temperature changes. Metallographic sectioning later confirmed recent crack growth at these locations.

Steam Lines

The boiler header results provide the basis for developing an acoustic system that will continuously monitor leaks and periodically monitor cracks in steam lines. Permanently installed sensors spaced along the pipe will detect and locate leaks that are likely precursors of pipe rupture. Periodically, engineers can test for pipe crack development by connecting acoustic emission-detection equipment to the sensor system and operating the plant in a transient mode. Startups, load changes, and brief temperature or pressure excursions can induce acoustic bursts from micro crack growth. By locating the sources of these bursts, engineers can target damaged areas for follow-up inspection and repair.
3.5.7 Acoustic Emission Detection Technique

Another aspect of the acoustic monitoring technology involves acoustic emission (AE) which monitors the sound transmitted by the component structure. The AE monitoring system is very similar to the acoustic leak detection system, except that the microphones are replaced by AE sensors made with piezoelectric elements. Also, the acoustic probe body is replaced by a metal rod also referred to as a waveguide, which extends through the casing and is attached to the boiler wall. This rod transmits the AE signal from the wall through the casing to the AE sensor.

The frequency bandwidth of the AE signal is much higher than the acoustic signal. Typical frequencies range from 50 kHz to 500 kHz. The lower cutoff frequency is again set to avoid background noise which can extend up to 100 kHz. The signal processing is essentially the same as the acoustic system. The rms values of the individual AE signals are calculated and compared to preset thresholds. More elaborate systems have been proposed and are under development to use cross-correlation methods to increase signal to noise ratio and improve leak location estimates.

The acoustic power generated by a jet of pressurized fluid emerging from a small rupture area was studied by one plant, who identified several characteristics of such acoustic energy. The higher frequency noise components are produced near the jet nozzle. Part of the acoustic power dissipated during leak outflow is transmitted through the structure metal. Also, various physical mechanisms are responsible for noise generation:

- Acoustic Emission from Turbulence, Depending on Dimensions and Geometry of Defect
- Acoustic Emission from Phase Phenomena such as Boiling, Sudden Flash, Cavitation
- Flow Over Rough Surface
- Coupling between Fluid and Structure

The acoustic emission generated by a fluid leak is a quasi-stationary broadband noise. This noise can be suitably characterized with its RMS value in the frequency band 50 kHz up to 1 MHz.

Instrument System

The system consists of a waveguide, AE sensor, electronic device for signal conditioning, data acquisition system, proper operation control subsystem, and control unit.
A block diagram of typical AE detection system for low pressure preheaters and steam headers is shown in Figure 3-14.

1. Waveguide
2. Acoustic Emission Transducer
3. Clamping Device
4. Signal Conditioning Unit
5. Multipoint Chart Recorder
6. RMS Voltmeter
7. Spectrum Analyzer

Figure 5-14 Acoustic Emission Detection System

3.6 Ultrasonic on-line Bearing Condition Monitoring

3.6.1 General Discussion

The condition of operating bearings can be monitored through the use of an ultrasonic transducer system. The transducers in this system can be installed in major rotating equipment in order to provide periodic or continuous inspection of the bearings while the equipment is running. The current condition of an operating bearing is indicated within a normal operational accuracy of $\pm .0002$ in. The rate of change of the condition of the bearing can be evaluated by trending these individual measurements. The remaining safe operating life of the bearing can be estimated from the trend information.

3.6.2 Ultrasonic Transducer System

Bearing failures often occur after a lengthy process of wear. Abrasive wear, adhesive wear, corrosion, and erosion can be tracked from the inception of the problem through the point of bearing instability with an ultrasonic transducer system. With such a system, the changing condition of the bearing can be monitored. The avoidance of forced outages and equipment damage is provided by such a system.
The system directly measures the loss of material from the surface of the bearing. The bearing condition is determined from evaluation of its dimensional change rather than using shaft movement or shaft/bearing gap as condition criteria.

**How the Ultrasonic Transducer System Works**

Active element ultrasonic transducers are installed in fluid film journal and thrust bearings. Transducers are placed in known or anticipated wear areas to maximize the ability to detect wear at its earliest stages. A specially designed instrument excites the transducers with a voltage pulse and reads their response. Installations in new or reconditioned bearings provide the ability to obtain direct accurate measurement of wear from the bearing surface.

Transducers are specifically engineered for use in a variety of bearing types and materials. In current installations, they are about the size of a pencil eraser. The transducers are mounted in the bearing so that the tip becomes part of the bearing surface. For example, bronze transducers are used in bronze bearings and babbitt tipped transducers are installed in babbitt lined bearings. In each case, the tip of the transducer becomes an integral part of the bearing so that during equipment operation, as the surface of the bearing wears, so does the transducer (see Figure 3-15).

There is a piezoelectric crystal mounted in each transducer. The system instrumentation sends a sharp voltage pulse to the crystal which then converts it into a sonic pulse. A sound wave travels from the crystal to the face of the transducer and "bounces" or "echoes" back. The echo re-excites the crystal and is converted back to a voltage pulse that travels back to the system instrumentation.

![Figure 3-15  Output without Temperature Compensation](image_url)
The energy in the voltage pulse is about $10^6$ joules with a frequency component of about 100 MHz. This type of pulse creates individual signals that are easily identified by the system instrumentation but results in negligible surface penetration of the voltage pulse from the inside of the transducer. Correspondingly, there are no detrimental effects at the bearing fluid film surface from the pulse.

The system instrumentation uses specially designed circuitry to emit the pulse, identify, and qualify the echo and then measures the time from signal emission to echo receipt. This time difference accurately translates into distance.

**System Output**

System data is read out in thousandths of an inch. The current condition of the bearing is determined from the individual readings from each transducer. Comparison of the current readings with the previous data tells if the condition of the bearing is changing or stable and gives an indication of how fast the condition is changing.

**System Accuracy**

The transducers and the electronic instrumentation both have unavoidable finite errors that affect the accuracy of the system. Some of these errors are correctable through calibration procedures, and some cannot be avoided.

**Transducer**

The transducer affects the accuracy of readings because the acoustic properties in a given material can vary from material sample to material sample. Polycrystalline materials have multiple crystal boundaries which deflect and reflect ultrasonic energy. As a result, ultrasonic waves can propagate in two different material samples at the same temperature with slightly different acoustic velocities. The acoustic velocity in a given material is also affected by the temperature of the material.

**Error Due to Temperature/Material Variation**

Some of this error due to temperature changes and material conditions can be compensated. Temperature shift is compensated by installing reference transducers in no-wear orientations or by building in an individual transducer a temperature reference point.

Material condition effects are controlled by sorting transducers by response characteristics during their fabrication and testing. The maximum uncorrectable error in readings due to temperature changes and material condition differences is $\pm 0.1$ mil per 22.5°C.

The error is reduced considerably through the use of temperature compensation. Figure 3-16 shows a series of readings from multiple transducers taken on an
installation in the thrust bearing of a 250 MW steam turbine. In this installation, there are no temperature reference transducers or self referencing transducers. The readings stay within a ±.2 mil accuracy, but due primarily to temperature shifts in the bearing, they tend to wander within that accuracy. Figure 3-17 shows a series of readings from one transducer installed in a thrust bearing.

Two reference transducers have been installed in no-wear orientations in this bearing (see Figure 3-17). Although little wear is indicated in the first year of operation of the bearing, the data in Figure 3-16 indicates that the bearing temperature differences have been compensated for with the reference transducers and the wear is measured as a smooth progression instead of showing relatively dramatic jumps due to temperature.

The use of transducers with self referencing capabilities is expected to improve the consistency of the readings even further. A test of the self referencing transducers has been run on tilting pad type thrust bearings at the Kingsbury Inc. test facility in Philadelphia, Pa. In this test, readings were taken on six transducer installations at 4000, 8000, and 12000 RPM with bearing loads of zero to 500 PSI at 100 PSI increments at each speed. Bearing temperatures were recorded (with embedded thermocouples) from 165°F to 295°F. Through all of these variable conditions, the system indicated readings on three transducers within an accuracy of ±.00004 inches. In the worst case, the readings varied by ±.00015 inches. These tests were first run in February of 1989. The results were repeated in a second running of the test in April 1989.

Instrumentation

The impact of the electronic instrument on the accuracy of the readings is due to the readout resolution error of the instrument.
The ultrasonic measurement instrument normally displays readings of a transducer to a resolution of 0.1 mils. At this resolution, a quantitation error of the reading displayed is introduced. A reading value is not rounded up and a value is not shown on the instrument until its display threshold is reached. As a result of the quantitation error, the display of the reading can be + 0.1 - 0.0 off of the true reading.

![Figure 3-17 Transducer Locations](image)

### 3.6.3 Overall Accuracy of System

When transducer variations are standardized with reference transducers, which have their own variations, static temperature readings can have a total reading inaccuracy of ± 0.2 mils maximum. This is somewhat improved with self-referencing transducers.

The total maximum inaccuracy of readings due to electronics quantitation, temperature changes, and material variations is ≤ (± 0.2 mils ± 0.1 mil/22.5°C). Standard calibration procedures and the development of the self-referencing transducer capabilities reduce this inherent error. Currently the normal accuracy observed is ± .0002 inches.
3.7 Thermography

3.7.1 General Discussion

Thermography is defined as an electronically produced image representative of thermal patterns on a surface. There is no requirement for thermography to produce quantitative information. Thermography has become a well recognized, cost effective information gathering tool for energy management and equipment diagnostics. This method is sensitive and permits evaluation of problems, not merely their detection and identification. Thermography can accurately identify the problem source while the equipment is functioning. Thermography depicts what is happening so that results can be rapidly compared against control settings and other types of operational information. Current operating conditions and performance can be determined for a wide variety of processes and facilities by using equipment that is now sensitive to extremely low temperature differences.

Typically, this methodology uses an infrared thermal scanning camera to record television-like thermal images on film or video tape. The information is then analyzed, resulting in a report indicating areas for repair and other data for diagnosing maintenance problems. Thermography instruments are relatively easy to operate, but considerable knowledge of the possible sources of error, such as surface Emissivity and reflections, is required to obtain accurate data and make the proper interpretation for sound engineering judgments.

3.7.2 Thermal Imaging Radiometers

Thermal imaging radiometers display an image of the heat patterns radiating from surfaces are designed to produce temperature information. This is important since none of these instruments measure temperature directly but must infer temperature from the measured radiant energy. The great advantage of thermal imaging radiometers over non-contact thermometers is that they allow rapid assessment of a situation via thermal patterns and show the operator exactly what is being measured. They also have a much faster response time (nanoseconds vs. milliseconds) than do non-contact thermometers. A thermal imaging radiometer performs some million measurements per second. Pattern recognition by the operator facilitates real-time or post processing analysis of the correct area at the proper time. With video recording and computer processing, tremendous amounts of thermal data can be archived, accessed, and analyzed. The major disadvantage of thermal imaging radiometers compared to non-contact thermometers is their cost which is typically 20 to 30 times higher.

Many types of non-contact temperature measurement instruments are available today. Nearly all rely on the same basic physical phenomenon: all real-world objects radiate energy; the amount of energy radiated increases with increasing temperature. The
Radiated energy is distributed over a band of wavelengths in the electromagnetic spectrum.

The spectrum spans from low frequency radio waves to microwaves, then to the infrared, visible-light, and x-ray wavelengths. The distribution for a specific object temperature is the Planck function. The peak of this curve moves toward shorter wavelengths as the object temperature increases (see Figure 3-18). The Planck distribution is modulated by the efficiency of the object as a radiator. This efficiency, called emittance, is 100 percent for a perfect radiator, called a blackbody. Real objects have emittances that are less than one and which can vary with wavelength.

Objects at or near room temperature have spectral energy distributions that peak in the middle infrared region, near 10 MM. A sufficient amount of energy is radiated to allow detection at great distances by a sensitive instrument. The consistency of the relationship between object temperature and radiated energy allows a calibrated instrument to perform highly accurate non-contact temperature measurements.

Scanned mechanically across the screen rather than with the large photosensitive surface typical of TV camera. These detectors must be cooled to cryogenic temperatures. Another class of system, the pyroelectric vidicon, is similar to a TV camera, employing a large, uncooled, thermally sensitive surface. However, because of the nature of the pyroelectric effect, these systems are difficult to quantify. The Schottky barrier is also a large surface obviating mechanical scanners. It has not yet been developed into a viable thermal imaging radiometer. Consequently, the discussion here is limited to mechanical scanning systems.

To perform accurate temperature measurements, thermal imaging radiometers incorporate a blackbody reference source that is viewed periodically by the detector for calibration. They use lenses and windows that transmit infrared wavelengths of electromagnetic energy; materials such as germanium, zinc sulfide, and silicon are typical. Optical filters can tailor the spectral response of thermal imaging radiometers to optimize measurement of (or transmission through) specific materials including gases, plastics, and flames. Low-pass, high-pass, bandpass, reject, and attenuating optical filters are available.

While thermal imaging radiometers employ many types of scanners, the specific type is seldom apparent to the operator. Nearly all systems incorporate scan conversion circuitry to create a TV-compatible output. The referencing technique may also be obscure since electronic circuits perform recalibration during the invisible blanking portion of the TV image. Specific information on system design and specifications can be readily obtained from the manufacturers.
3.7.3 Emissivity Considerations

Concisely, Emissivity is the ratio between the temperature of an object as read by a radiation detector and its actual temperature. Put another way, Emissivity is the amount of radiation that is emitted, divided by the total possible radiation that it could emit if it were a perfect radiator (blackbody). The Emissivity of an object is solely a surface phenomenon; this is true in the visible spectrum as well. If that surface becomes dusty, then the real color or intensity is changed by the dust. The real intensity of radiation that an infrared instrument picks up depends upon the atmospheric absorption, the angle of observation, the contribution due to the ambient temperature, convection and reflection, the size of the object, and whether or not there are any spectral absorption or radiation effects.

Figure 3-18 Temperature vs. Wavelength
One other aspect of Emissivity is that when the temperature of an object is changed, an irreversible change in Emissivity may occur. An example of this is the case of highly polished aluminum which will eventually oxidize as the temperature is increased. When returned to the original temperature level, it will have a different Emissivity.

In general, dielectrics have relatively high emittances (0.8 to 0.98). Bright metals have relatively low emittances (0.05 to 0.20). Oxidized metals generally have intermediate emittances (0.4 to 0.7). These are rule-of-thumb values for reasonably flat surfaces. Geometry plays a major role in the emittance of a material. Concave shapes, such as recesses and holes, can dramatically increase emittance. For example, the thermal image of recessed bolt holes in a hot metal plate will often look 'hotter' than the metal surface. This is usually due to the increased emittance caused by the recess. In fact, a recess seven times as deep as its diameter will have an emittance close to one regardless of the material. This emittance contrast can be used advantageously.

3.7.4 Applications for Thermography

This guideline is limited to electrical equipment and the data required to estimate the condition of the equipment. Any electrical equipment can be monitored, but electrical equipment where deterioration or malfunction would show up as excessive heat are the most likely candidates. A suggested list of equipment and components and areas and conditions to scan for is as follows:

- Transformers
  - Transformer Bushings
  - Pothead Connections
  - Radiant Cooling Tubes
  - Unbalanced 3-Phase Loads

- Switchgear and Breakers
  - Terminal and Tap Connections
  - Unbalanced 3-Phase Loads

- Bus Duct
  - Load Distribution
  - Loose or High Resistance Joint Connections
  - Bus Plug-ins
  - Fuse Connections
  - Plug-in Connections

- Power Factor Capacitors
  - Proper Operation of Individual Units of Capacitor Banks
  - Lead and Fuse Terminal Connections

- Motors
  - Bearing Temperature Comparison
- Unbalanced 3-Phase Load
- Shorted or Open Windings (Open Motors)
- Brushes, Slip rings and Commutators

> Lighting
- Fixture Operational Status - Burnt out Lamps or Connected Ballast
- Proper Operation of Separately Mounted H.I.D. Ballast

> Distribution Panels
- Circuit Breaker Operation
- Fuse and Fuse Holder Connections
- Unbalanced Loads

> Control Panels
- Transformer and Panel Heating
- Loose, Dirty or Poor Mating Conditions of Starter and Relay Contacts
- Loose or Dirty Wire Terminal connections
- Power Factor Correction Operation
- Unbalanced 3-Phase Load

> Miscellaneous
- Disconnect Switches
- Knife Switches
- Motor Controllers
- Cables
- Junction Boxes
- Cable Splices
- Terminal Boards
- Voltage Regulators

When determining the level of performance required to accomplish a desired task, the following basic physical facts should be kept in mind:

➢ Copper melts at under 1085°C and aluminum melts at 650°C
➢ Most wire and cable insulation are rated for maximum operating temperatures of 60 to 90°C
➢ Copper will over long periods of time anneal at temperatures in excess of 100°C
➢ Tensile strength of copper starts to decline at 150°C

Therefore, the temperature viewing range of infrared imaging equipment need not exceed 100°C. In order to detect a problem during its developmental stage, before
serious consequences result, it will have to be detected at temperatures considerably below 100°C. Also, electrical failures caused by heat buildup rarely, if ever occur at hardware temperatures below the minimum viewing temperature of 0°C.

It is important to recognize that exact quantitative measurement of temperature and/or temperature difference is not essential.

There are very few requirements needed for thermographic inspections. The first requirement is that the equipment be in service. Heat buildup varies directly with the square of current and the loading of the equipment will directly affect the thermographic image. Therefore, a consistent loading of the device or equipment should be maintained if the temperature will be tracked.

In most cases, a thermographic survey is a comparative type of survey and hot spots are the indicators of problems or potential problems. In this case it is only necessary that the equipment be energized to near full load. While this is not absolutely necessary, most manufacturers of thermographic equipment recommend that the current level be at least 40% of rated full load.

3.7.5 Measurement Accuracy

Using an object’s radiation to measure its temperature is more difficult than attaching a thermometer or thermocouple. But sometimes this is the only convenient way. Other times, it is only necessary to see large area heat patterns, and that is difficult to do with a thermocouple or thermometer. In these cases, a person can resort to any of a number of radiation measuring devices which will give a temperature indication (bolometers, pyrometers, thermopiles, line scanners, infrared viewers and thermographic systems). All these instruments claim to measure relative temperature by non-contact means, and they are limited in their accuracy by the same theoretical and practical considerations. So how does one use these instruments to obtain a practical, accurate temperature reading?

To get a practical temperature reading, set up as ideal a circumstance as possible by following the Measurement Consideration Checklist below. By following this checklist, you will get an idea of how accurate your end results should be. If it appears they would not be very accurate, then use the second method by measuring, coating, covering, enclosing, referencing, and calculating.

**Measurement Consideration Checklist**

1. The way a surface appears in the visible spectrum is the way that surface will appear in the infrared as well. Take temperature readings from things that are dull in the visible spectrum.
2. Get close enough for an object to occupy a sizable section of the screen. Focus on the object.

3. Look at the object face on.

4. Move around to eliminate reflections.

5. The material an object consists of does not matter; it is the surface of the object that counts.

6. Try to work on a windless day.

7. The higher the temperature above ambient, the better the reading.

8. Watch out for the sun, for light, and for spectral absorption and emission.

A key factor to remember when taking thermographic data is that the radiation is a surface phenomenon only. There can be the shiniest, most highly polished surface behind a layer of corrosion, but the Emissivity and reflectivity will relate only to the corrosion. Simply stated, radiation sensing instruments only get to the surface of the device. The one exception to this "surface only" rule is where a surface consists of a transmissive material; for example a polyethylene plastic cover or other thin plastic cover. In these cases, the infrared radiation passes through the plastic coating and the instrument readings are of whatever is directly behind it.

However, most electrical scans are of equipment in metal enclosures that will not give good thermographic readings unless the heat is so intense that it will heat the enclosure. Therefore, panel doors and breaker cabinets should be opened to get good scans. In some cases, breaker panels may have to be removed to get good results.

3.8 Replication

3.8.1 Introduction

Plant components operating at high temperature are susceptible to creep micro cracks which could lead to fracture failures. Replication is a nondestructive-metallographic examination that can identify creep micro cracks approximately one micron in size. Crack-susceptible locations can be monitored to provide crack growth information. Components do not require replacement or repair until these micro cracks have grown to form small creep macro cracks. The replication test provides assurance of safe
operation for the useful life of the component. This technique prevents the unnecessary retirement of plant components and results in an economic savings.

3.8.2 Basic Theory

Replication is a nondestructive evaluation method used to inspect the surfaces of large non-transportable plant components including boiler parts and piping. The method includes the following steps:

- Polishing the Surfaces of Selected Component Areas
- Preparing Replicas of the Polished Area
- Examining the Replicas Under Microscope for Evidence of Cavities, Micro cracks, or Macro cracks
- Establishing the Damage Parameter, Remaining Component Life, and Inspection Interval

The first step in the replication method is to polish the surface of selected component areas. The areas chosen should be the crack-susceptible locations. If these areas are not identifiable with adequate certainty, such as in straight piping, the replication method is not suitable and other methods should be employed. For those crack-susceptible areas that are subjected to internal pressure and additional forces, such as bends and welds, the replication method is very useful. Polishing the surface removes foreign matter and exposes the surface allowing a representative imprint to be made.

After the surface is polished, a cellulose acetate tape is applied. An appropriate length of tape is needed to cover the area to be evaluated. One side of the tape is softened with acetone so that it can be molded to the surface. The tape should only be softened through half the thickness, not clear through. This softening process is an "art" that becomes more familiar with repeated use. The softened side of the tape is then applied to the surface. The acetone will seep through the tape and diffuse through the backside. When it evaporates, the tape will harden. Bubbles should be kept from appearing on the tape. The process takes between 5 to 15 minutes depending on the amount of acetone and the tape thickness and size.

The acetate replica will lift from the surface as the tape hardens. Otherwise, the tape can be carefully stripped off. This imprint contains the replicated features of the component's surface. For example, a microscopic crack in the component's surface will appear as a microscopic ridge and a microscopic ridge will appear as a microscopic crack. The replica can be examined directly under an optical microscope for gross detail or under an electron microscope for higher resolution. The process can be taken one step further if better definition of details is desired.
A very thin vacuum metal coat is applied over the replica. A reflective metal, such as aluminum, gold or copper should be used. The result is an opaque replica which is easier to examine. Also, if a scanning electron microscope is to be used, a replica with a conductive surface is more readily examinable.

This replication technique is used on both microstructures and fractures. However, a fracture surface is more rough than a microstructure surface so a thicker acetate tape is used in making the replica.

Direct evaluation using an acetate replica is the most common replication technique. However, for high resolution examination, biotin, an acetate type liquid substance, is used to make the replica. A biotin replica is made using a process similar to the one just outlined. However, it is directly applied to a smooth, polished surface area and removed when it has hardened into a plastic-like mold. At this stage, the biotin replica can undergo the same direct evaluation applied to the acetate replica. Biotin is used in place of the acetate tape because the sample preparation process is taken several steps further so that the replica can be viewed at higher magnification.

The biotin replica is vacuum coated with a light coating of a heavy metal at a low angle. This will highlight high spots giving a shadow effect. Then a direct carbon film layer is applied. The thickness of the carbon layer is determined by "trial and error." Much like the softening of the tape, it becomes easier to determine with repeated usage. The replica is then cut into small parts (approximately $1/8$" squares). These parts are immersed in acetone. The acetate will dissolve and float away leaving behind a shadow film. This shadow material is removed from the acetone with a microscope grid and viewed under a transmission electron microscope.

3.8.3 Evaluation

Whichever method is used the result is to detect creep damage in the component's surface. Four classes of damage parameter as shown in Figure 3-19 have been identified:

A. Isolated cavities
B. Oriented cavities
C. Micro cracks
D. Macro cracks
Figure 3-19 Surface Damage
These parameters are shown in Figure 3-20 normally progress with time. For damage parameters A and B, damage depths less than 10% of the material thickness are found. For damage parameter A the component should continue to be observed, and for damage parameter B the component should be observed on fixed inspection intervals. Damage depths greater than 10% of the component thickness are found for damage parameters C or D. For damage parameter C the component should be placed in limited service until repair. For damage parameter D the component requires immediate repair.

3.8.4 Inspection Intervals

The results from 80 replicas, starting at damage parameter A, taken annually over a five year period indicate a damage progression at most to damage parameter B. A plot of these results shows that three years of further operation may be permitted without increase in damage parameter.

The results from 59 replicas, starting at damage parameter B and taken annually over a three year period, indicated a damage progression at most to damage parameter C. A plot of these results shows that one and one half years are permitted without increase to damage parameter C (see Figure 3-21).
Figure 3-21 Progression from Damage Parameter A to C
As soon as creep results in macroscopic damage, the safety of further operation, which may be desirable prior to repair or replacement can be determined by fracture mechanics.

If the results of the analysis allow for continued operation with or without restriction, the analysis should be repeated at the end of a specified operation period.

At present replication is the only proven nondestructive evaluation method that can detect creep damage of highly stressed components at an early stage. The method allows for life-extension of components and the elimination of unscheduled repair work with continued safe operation. The inspection intervals stated above can be incorporated into a predictive maintenance testing and inspection program. Data can be retained over time to develop creep crack history of plant components and correlated to other parameters such as load, major excursions, and chemistry data.

### 3.9 Nondestructive Evaluation

#### 3.9.1 Introduction

With construction costs rising, a heightened concern has developed to keep existing equipment operating longer. Experience has shown that equipment serviceability can be increased through a comprehensive plant maintenance program. Many traditional maintenance techniques require the removal or machining of individual components. These examination techniques may actually be counterproductive to the goal of keeping a plant in operation. Nondestructive evaluation can determine the initial conditions and how degradation affects the performance of materials. In knowing the extent of material degradation, unexpected failures can be prevented by performing maintenance in advance and eliminating the disruption of plant operations.

#### 3.9.2 Types of NDE Inspections

Basically, there are two types of NDE inspections, surface or subsurface. Surface inspection is considered to be the upper 0.050 inch of a material and includes the following NDE methods:

- Visual Inspection
- Liquid Penetrant
- Magnetic Particle
- Eddy Current
Subsurface, also called volumetric, are inspections from 0.050 inches below the surface through the total thickness. Subsurface inspections include the following methods:

- Ultrasonics
- Radiography

The type of NDE inspection employed depends on the material type, size, thickness, geometry, and accessibility. The method selected must be sensitive enough to detect any abnormality, flaw, or irregularity that may develop into a serious imperfection. Whatever the selection is, the first method used should be visual.

3.9.3 Description

Visual

Visual inspection sometimes reveals defects not readily exposed by other methods, particularly to a trained analytical observer. Section V of the ASME Boiler & Pressure Vessel Code states that visual inspection is normally done when access is sufficient to place the eye within 24 inches of the surface to be examined, and at an angle of not less than 30° to the surface. The code also specifies an illumination of 15 fc (foot candles) for general examination and 50 fc for detection of small abnormalities. For example, a 100-watt incandescent light bulb at a 10 foot distance will give a 1.25 foot candle illumination directly below the light source, or a single 96-inch, 110-watt fluorescent light at 20 feet will give a 1.24 foot candle illumination. Generally, work areas in the plant have not been designed with enough illumination for visual inspection. A light meter, usually calibrated in foot candles, can determine the actual illumination and whether additional lighting is required. While the unaided eye can examine surface finish, the aid of special equipment or methods enhances the visual image of the defect. These aids include mirrors, microscopes, periscopes, telescopes, and closed circuit television. Less familiar visual aids are boroscopy and fiber optic devices. These latter two will be covered in the following section.

Liquid Penetrant

Surface enhancement methods can be used to show flaws which were not detected visually. One such method is liquid penetrant. Liquid penetrant is one of the simplest and most economical techniques of NDE that can be used on any material. Liquid penetrant works on the principle that a liquid solution applied to the test area will enter the defects or flaws open to the surface through capillary action. After surface drying, the excess penetrant is removed and the penetrant left in the defects or flaws is developed (drawn out) to highlight their locations. Three major types of liquid penetrants are available.
The first two types, because of their application techniques, are used mainly in laboratories and shops. The third is used in the field. Essentially, all three types require the same seven-step procedure.

1. Precleaning - since the test will not penetrate discontinuities that are not open to the surface, precleaning is required. (Figure 3-22)

2. Penetrant application - may be applied to the test surface by spraying, immersion, or brushing.

3. Dwell time - allows penetrant to enter tighter discontinuities.

![Figure 3-22 Liquid Penetrant Examination](3-70)
4. Excess surface penetrant removal - must remove excess from the surface, but not the discontinuities.

5. Surface drying - must dry test area before applying developer.

6. Developer application - draws the penetrant solution out of the discontinuities to show their locations.

7. Interpretation of results - results are interpreted by visual inspection. May be enhanced by fluorescent penetrants.

**Liquid Penetrant Equipment**

The liquid penetrant system usually comes in a kit containing penetrant, remover, and developer. The penetrant and developer are usually supplied in an aerosol spray can to aid in field applications.

**Particle Inspection**

Techniques for using liquid penetrant require surface preparation and only reveal defects on the exposed surface. Magnetic particle inspection can be used on ferromagnetic materials to detect surface or slightly subsurface defects without extensive surface preparation. This method is based on the principle that ferrous material placed in contact with a magnetic source will develop a magnetic field. Defects in the material will distort the magnetic field. When a magnetic field is created in the material and the test site is sprayed with fine magnetic particles, the particles will line up to form surface patterns. (See Figure 3-23). Breaks in the surface patterns reveal the location of the defects. The closer the crack is to the surface the sharper the indication, since the field is more distorted. Deeper cracks give a wider indication. This technique involves three steps:

1. Magnetization of the material
2. Application of the magnetic particles
3. Interpretation of the pattern formed

Magnetization of the material is produced by a magnetic yoke, coil, or cable placed around or through the material. Application of the magnetic particles is done by dusting or spraying. The magnetic particles applied reveal defects by distortions in the magnetic field. Field leakage paths are provided by the particles giving indication of the size and location of defects. Generally, only flaws perpendicular to the magnetic field are detected. It is best to orient the magnetic fields in several directions to inspect the material.
Magnetic Particle Equipment

Magnetic particle equipment consists of a magnetizing unit and magnetic particles. Simple equipment for testing small casting or machine parts is portable and contains either an A.C., D.C., or a Permanent magnetic yoke. The magnetic yoke creates the magnetic field in the ferrous test material. The magnetic particles placed on the test surface will align themselves with the magnetic field. Either dry powder or wet material particles are used. Commercially available dry powders come in gray, yellow, black, and red. Commercially available wet method materials come as either fluorescent or non-fluorescent. The non-fluorescent are similar to the dry powders except the powder is suspended in either oil or water. The fluorescent material also uses a suspending agent.

Other magnetic particle equipment is available for testing large test pieces. Both portable and stationary bench-type equipment is used. Specialized bench-type equipment can be set up for testing engine crank shafts and other large heavy parts.

Demagnetizing

In some cases it may be necessary to demagnetize the test material either before or after magnetic particle testing. Demagnetizing before testing may be required in the cases where strong residual fields exist in the material. Demagnetizing after testing should be performed if magnetization of the material will interfere with the
operation of instruments which are sensitive to magnetic fields, retain particles of metal on the test piece (ball bearings, gear teeth), or interfere with plating or painting of the surface. If it is equipped, demagnetization can be performed with the magnetizing equipment. This is generally true for A.C. equipment.

3.9.4 Eddy Current Inspection

Where magnetic inspection requires contact with the test material surface, eddy current inspection does not. Eddy current testing is based on the principle that when an alternating magnetic field is brought close to a conducting test material, eddy currents will be induced in the material creating a secondary opposing magnetic field. The result of the opposing magnetic field is a reduction or impedance in the current flow. When discontinuities are present, the eddy currents are distorted and the impedance of the inducing magnetic coil is changed. The change in coil impedance indicates the magnitude of the eddy currents and their phase relationship to the inducing current.

The basic components of eddy current test equipment are the induction coil, the power supply, and a coil response indicator. Two main types of coils are used: absolute and differential. The absolute coil is a single coil that measures bulk characteristics, i.e. conductivity, dimension, and permeability. (See Figure 3-24) The differential coil uses two coils that electrically oppose each other. Bulk characteristics of the test material cancel out, but small defects will show as an electrical difference between coils.

Coil choice depends on test application. For surface testing, a surface probe or encircling donut type coil is used. For internal surfaces, such as tubing, a small diameter coil is used.

3.9.5 Radiography

Radiography is one of the earliest NDE methods used in the utility industry to verify welds. It is a process that uses penetrating radiation such as X-rays or gamma rays. Some of these rays are absorbed as they pass through material. The amount of absorption depends on the thickness and density of the material at that location. The unabsorbed radiation passing through the material is detected and recorded, usually on photographic film. Using the penetration and absorption characteristics of the material, the film can be examined for internal discontinuities. Defects and thin regions absorb less radiation allowing more radiation to pass through the material and land on the film. When the film is processed, these areas will appear darker in contrast to the rest of the film. The film image is a "shadow" picture of the material structure.
**Film Image**

The film image sharpness and distortion depends on the distance between the radiation source and the material and the distance between the material and the film. The optimum sharpness is obtained when the distance of radiation source to the material is relatively great and the distance between the material and the film is

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**Figure 5-24 Eddy Current Test Coils**

- **Inside Coil Circular**
- **Encircling Coil-Circular**
- **Spring-Loaded Surface Coil**
small. Also, as the radiation source size is decreased, the image sharpness increases. Film image distortion is caused by the plane of the material not being parallel to the plane of the film or the radiation beam not being directed perpendicular to the plane of the film. To determine if a "good" shot has been taken, a penetrometer, a piece of metal with holes, is used. It will appear undistorted on the film for a "good" shot. In addition, it can be used as a standard for determining defect size.

Radiography Equipment

Radiography equipment consists mainly of a radiation source and additional equipment used to produce the visual representation of the material. The X-ray tube is one source of radiation. The tube consists of two electrodes enclosed in a high vacuum envelope of Pyrex type glass. Another source of radiation is gamma rays. Gamma rays are produced by radioactive material which cannot be shut off or controlled. The radioactive material must be adequately shielded when not in use.

Radiographic Film

Whether the radiation source is X-ray or gamma ray, the radiation passes through the material and lands on the film. Radiographic film consists of a thin, transparent plastic sheet coated with an emulsion of gelatin containing very fine grains of silver bromide. When it is exposed to X-rays, gamma rays, or visible light, the silver bromide undergoes a chemical reaction. This exposure to radiation or light creates a latent image on the film. With further processing the film is developed to make the image visible. The film image is a shadow picture of the material and can be interpreted by its contrasting density differences. Areas that have received large amounts of radiation will appear dark gray. Those areas receiving less radiation appear light gray. Homogeneous material with minor defects and little thickness variations will have a low contrast, and material with large defects and thickness variations will have a high contrast.

3.9.6 Ultrasonics

Ultrasonic testing is a NDE technique for the inspection of materials and products utilizing the transmission of high frequency sound waves, also known as ultrasound, in the test material. This is in contrast to radiographic inspection which uses either X-rays or gamma rays.

The ultrasonic testing of materials makes use of mechanical vibrations or oscillations of the atoms in matter to conduct the tests. These oscillations travel as
waves which can be measured and analyzed to determine the structure of the material.

Sound and ultrasound are both oscillations in a material. The difference is that ordinary or audible sound has a frequency below 20 kHz (20,000 hertz) which is the upper threshold of human hearing, and ultrasound used in material testing has a frequency between 200 kHz and 16 MHz (16,000,000 hertz). The corresponding wavelengths are very small. When waves strike a surface or interface between materials, they are either reflected or transmitted, or both. The reflection of the waves gives an indication of the material structure and where defects are located. With small wavelengths, defects are more readily determined.

Using a piezoelectric transducer, ultrasound electrical frequencies are transformed into mechanical vibrations in the test material. These vibrations are propagated through the material in the form of waves. The wave motion is either longitudinal or transverse depending on whether the vibrations are parallel to the wave propagation or perpendicular to it. The piezoelectric transducer not only transmits the ultrasonic waves but it also absorbs the reflecting waves and converts them into an electrical signal giving an indication of the distance traveled in the material structure before being reflected.

The distance the waves travel can be measured on a CRT or oscilloscope screen. The initial pulse or echo is from the front surface of the test material and the last pulse is from the back surface. Any pulses in between are caused by reflections off of discontinuities. Therefore, the CRT monitors the speed of the ultrasonic wave reflection in the material, and reflected waves that return before the reflection off the back surface indicates the location of discontinuities.

**Ultrasonic Equipment**

Each manufacturer of ultrasonic test equipment builds in features that are peculiar to that particular brand, but all general purpose units are similar. The usual way to break a unit into components is by function: the power supply, pulse generator, receiver-amplifier, clock, oscilloscope, and transducer. In some equipment the transducer and receiver are the same component. This description is for an A-scan pulse echo instrument which is, by an extremely large margin, the most common ultrasonic test equipment in use.

The power supply provides the energy to each of the components. It usually draws on 120V or 240V A.C. line power, although many portable instruments are battery driven.

The pulse generator or pulsar produces an electronic pulse at the desired frequency when triggered by the clock. The primary frequency, the pulse duration, the profile of the pulse envelope, and the pulse repetition rate are features of the pulse.
generator. They may or may not be adjustable. The electronic pulse is transmitted to the transducer.

The receiver-amplifier takes the return signal from the transducer, amplifies it, and otherwise processes it for display or data processing. The output signal from the receiver is customarily displayed on an oscilloscope.

The oscilloscope displays the output signal from the receiver-amplifier in one of two modules: RF (radio-frequency) mode or video mode. The oscilloscope gives complete waveforms in the RF mode, but only peak intensities are shown in video mode. Some units operate on only RF or video, while others allow for selection of either mode by the operator.

The clock is an electronic device which produces logic pulses and references voltages and waveforms. These pulses, voltages, and waveforms serve to coordinate the operation of the instrument.

The transducer mechanically vibrates in response to an applied voltage or produces a voltage in response to an applied mechanical vibration. The former is a sending transducer and the latter a receiving transducer. Transducers will be more completely discussed in a later section on vibration monitoring. A couplant is required on the transducer to ensure contact with the test material.

3.9.7 Application of NDE Methods to Power Plant Components

Boilers

The leading cause of forced boiler outages, as reported by the Electric Power Research Institute (EPRI), is tube leaks. Causes of tube leaks include erosion, fatigue cracking, hydrogen damage, and exfoliation. Boiler tube inspections conducted during planned outage periods can reveal many of the impending tube leaks. Tube wall thickness can be compiled and trended to determine erosion patterns in the boiler. Areas of the boiler that are most susceptible to erosion are the highest heat zones (the sidewalls at the flame level), the area around the sootblowers, and the tighter spaced areas in the superheaters, economizers, and reheaters. Comparison of a present inspection to a past one can establish erosion rates and predict tubing replacement.

Ultrasonic testing is the most widely used NDE inspection for inspection of boiler tubes. It can also be supplemented by visual, liquid penetrant, and magnetic particle in other areas of the boiler. Eddy current testing can also be used to measure tube thickness. Critical boiler components requiring NDE inspection are the steam drum, water drain, downcomers, headers, bottom blow piping, and the boiler air casing. NDE inspection in these areas can determine sagging, stress cracking, and weld cracking.
Replacement criteria with regard to tube wall thinning should be defined by the manufacturer. These will vary as older boilers were built with thicker tubes and can therefore withstand more erosion. Generally with older boilers, the criteria were that the tube should be replaced or built up when the loss is 70% of the original tube wall thickness.

Condensers and Feedwater Heaters

The most common problem with condensers and feedwater heaters are tube leaks which adversely affect the chemistry of the boiler feedwater. Leakage may also be caused by deterioration starting on the steamside of the tube wall, by leakage at the joint between the tube sheet and the tube, or by cracking of the tube wall. Major causes of tube wall deterioration are galvanic corrosion, water or steam, impingement erosion, deposit attack, dezincification (on brass tubes), and pocket corrosion. The NDE method of eddy current testing can identify the tubes that have experienced major wall degradation and those that should be plugged to prevent in-service failures. Also, data collected from eddy current testing can be trended to establish tube failure patterns and retubing requirements.

Turbine and Generator Rotors

In the 1950's, through the use of new materials, turbine and generator rotor failure was thought to have been alleviated. However, recently the failure of the Gallatin TVA Turbine Rotor has prompted a re-examination of reliability of existing 1950 C-grade turbine rotors. The turbine rotor is inspected using visual, magnetic particle, and ultrasonic testing. Ultrasonic testing is used to detect subsurface flaws. Magnetic particle and liquid penetrant are used to detect surface defects. Cases have been documented where generator windings and components have been refurbished only to have the rotor recommended to be retired. However, uncertainty regarding inspection/lifetime prediction processes has caused premature retirement of rotors and operation of defective ones.

NDE inspections conducted on rotors are:

- Bore visual inspection
- Bore magnetic particle inspection
- Peripheral ultrasonic inspection
- Peripheral magnetic particle inspection

Rotor inspections are conducted routinely with a complete inspection conducted within five year periods.

Inspection results are compared to the results of previous tests and the initial acceptance test for that rotor. Maintenance, repair, and operation history are also

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reviewed. From this information, crack growth calculations can be made to determine the useable material strength of the rotor. Generally, a rotor is placed in operation with a recommended interval between service inspections. The interval is based on certain starting, stopping, and loading instructions.

Along with the inspection of the rotor, the coupling assembly should be visually inspected for discoloration, oxidized oil deposits, loose coupling studs or bolts, fretting erosion, and corrosion. A magnetic particle inspection should be conducted of all available surfaces.

Turbine Blades

The nature of blade failures is such that the initial fracture of one blade can progress to massive destruction, leading to weeks or months of forced outage. Inspection and early identification of blade cracks can reduce the rate of catastrophic failure; hence the importance of using the optimized inspection technique. Turbine blades are routinely inspected during planned outages. Available surfaces are inspected by liquid penetrant and magnetic particle testing.

Areas that should be tested for cracks using liquid penetrant and magnetic particle are the:

- Wheel or bucket dovetail
- Bucket neck
- Notch cross keys or material around the keys
- Trailing edge of the bucket vanes
- Root of the tenons
- Bucket covers
- Brazed tie wires

Any of these areas found to have cracks can further be tested by ultrasonic methods to determine the severity of the crack and the necessary repair procedure.

3.10 Fiber Optics

3.10.1 Description

Fiber optics is used in communications, measuring various parameters (a relatively new field), and visual inspection. In general, most power plants are interested in the use of fiber optics to visually inspect inaccessible areas. Fiber optics normally requires shutdown and opening of the equipment. In this sense it is not a true predictive maintenance technique.
Fiber optics offer many advantages. It is inexpensive, reliable, sensitive, rugged, resistant to electromagnetic interference, inert to explosive gases, small in size, light in weight, and has few moving parts.

Fiber optics consist of an assembly of transparent glass fibers bundled together parallel to each other. This bundle of fibers has the ability to transmit a picture from one of its surfaces to the other around curves and into otherwise inaccessible places without loss of definition and light by a process of multiple internal reflections. Each fiber in the bundle carries light independently of the others and must be precisely aligned to allow transmitting images without distortion.

The fiber is a long cylindrical structure, usually with a circular cross-section. In its simplest form it has two regions. The inner region is the light-guiding core surrounded by a cladding. The cladding allows handling of the outer region (external to the cladding) without disturbance to the transmission characteristics. Also, the cladding has a low refractive index, preventing light entering the end of one fiber to escape or pass out laterally to a neighboring fiber.

3.10.2 Fiberscope

Fiberscopes are portable instruments weighing approximately six pounds. They consist of thousands of precisely aligned glass fibers (fiber bundle) with an objective lens at the distal end of the probe and a magnifying eyepiece at the other. The objective lens focuses the image, which is then transmitted via multiple internal reflections, up the scope to the eyepiece where it is magnified for viewing. A second fiber bundle transmits light down the scope to illuminate the viewing area. The light, in most cases, is powered by a battery.

One variation of fiber optics has recently taken is the interpretation of the viewed surfaces, while at the same time maintaining a permanent record of the observations. State-of-the-art automation is provided by utilizing photodetector optics and digital image sensing. Photodiodes located in the scanning camera on the probe generate analog electric pulses that are proportional to the impinging light intensities. The pulses are then converted into binary-coded signals. These signals are counted to determine the position of flaws. Flaw sizes can also be determined by using pulses between two points and marking approximate transitions in light value.

3.10.3 Power Plant Use

Fiber optics are widely used throughout the industry as a means to access areas of inaccessibility. For predictive maintenance purposes, the use of fiberscopes allows checking turbine blading without removing the casing. Typically fiberscopes are also used to inspect the interiors of heat exchangers, steam generators, boilers, pumps, engines, and various other types of equipment without having to fully open or disassemble the component.