Steam turbine risk assessment project: Inspection and overhaul optimization of steam turbines

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ABSTRACT

The pulp and paper industry wants to increase time between overhauls of steam turbines to reduce direct overhauling and inspection costs. Machinery engineers sometimes express the basis for justifying additional overhaul and inspection work as a "risk of failure." The aim of the Steam Turbine Risk Assessment Project (STRAP) was to develop a methodology and model to address optimization of overhauls by identifying and quantifying the "risk of failure" associated with maintenance, operation, and engineering practices applied to steam turbines. This paper details model development, demonstrates model application to evaluate a turbine, and displays the results achieved through testing of the analysis.

Application:

A STRAP model is part of a computer program that allows "what if" scenarios for evaluating individual turbines on a cost-risk-benefit basis. The results are useful to optimize an overhaul and inspection process for steam turbines, recommend spares, and help with run-repair-replace decisions.

Most engineers in manufacturing are now familiar with phrases such as "profit and loss statement," "stockholders demand for return," "time value of money," "data driven," "just in time," "return on investment," etc. Engineers in the pulp and paper industry have also adapted to working in an industry that experiences large swings in the market that have recently become even faster and more severe. Business and accounting factors are now a major part of the machinery operation and maintenance business due to the need to reduce the costs of operation manufacturing facilities while maximizing production and minimizing production interruptions—increasing availability. All these factors and the capital intensity of the pulp and paper industry demand management of the manufacturing capital assets of the industry using the best engineering and management practices.

Planning and justification of maintenance overhauls of steam turbines in the pulp and paper industry are good examples of these new concerns. An overhaul of a large turbine—greater than 20,000 hp—may cost several hundred thousand dollars. A considerable cost in lost paper production also exists since most mills must shut down at least part of their manufacturing process during a typical 15–20-day turbine "turnaround." Maintaining full production during a major turbine overhaul would require purchased power. Many mills do not have an adequate utility tie to offset the lost power. If they do have the utility tie, the purchased power cost is higher than self-generated power.

Failure to perform a scheduled inspection and overhaul in time can lead to unexpected deterioration of a turbine and the need to extend the duration of the turbine's planned overhaul to complete repairs. Turbine failure or an unexpected outage are also possible. These scenarios could possibly result in greatly increased expenses from hundreds of thousands to millions of dollars.

Whether a turbine drives a powerhouse generator, a paper machine line shaft, or other pieces of critical equipment, the maintenance engineer must employ the best available practices to prioritize, schedule, and justify turbine maintenance requirements.

PROBLEM

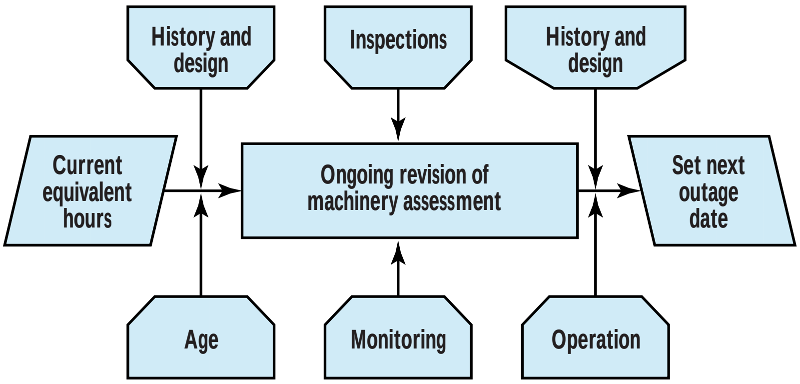
No industry guidelines or only very limited ones currently exist on which to base turbine inspection and overhaul intervals. Vendor recommendations are available. They are often very conservative because they fail to consider the economic consequences of an inspection and overhaul completely. A trend exists to extend the intervals using cost considerations. The databases of a major underwriter indicate that steam turbines are major machinery loss items for underwriters *(1)*. A recent publication showed that significant turbine mechanical damage can occur that is not readily discernible by monitoring performance and external inspection techniques *(2)*. This information indicates that a risk accompanies inappropriate inspection and overhaul intervals. This risk has the following relationship:

$$\text{Risk} = \text{likelihood of event} \times \text{consequence} \qquad (1)$$

Although considerable discussion of risk is available, calculation of risk with respect to inspection or overhaul intervals on turbines does not follow any well-defined or agreed-upon methodologies. Accurate calculation of the cost of avoiding the risk, i.e., by using overhaul or main-

Group	Turbine description	Power, 1000 kW	Power, 1000 hp	RPM	Inlet steam temperature, °C
1a	Single case driver	14.9–74.6	20–100	> 3,000	> 510
1b	Single case driver	14.9–74.6	20–100	> 3,000	< 510
2	Single case driver	7.5–14.9	10–20	< 11,000	
3	Single case driver	< 7.5	< 10	< 8,000	
4	High speed backpress	< 22.4	< 30	> 8,000	< 510
5	General purpose	< 3.7	< 5	< 6,000	< 400

I. Classification of turbines analyzed by risk assessment procedures



1. Outage planning factors

tenance activities, is possible in financial terms. Determinations of the cost of the consequence, losses associated with a failure, and likelihood of occurrence are more subjective. Cost of inspection, overhaul, and judgement currently drive the decisions rather than relative risk.

Considerable interest exists in industry to evaluate the combined issues of cost of inspection and overhaul and the risk of not performing these activities better. The American Society of Mechanical Engineers (ASME) has developed a methodology on Risk Based Inspection *(3, 4)*, and an American Petroleum Institute (API) publication is also available *(5)*. The basic methodology of the Steam Turbine Risk Assessment Project (STRAP) incorporates "risk" that includes both an engineering and a financial impact into the decision process making it attractive for use in machinery inspection and overhaul evaluations. This paper discusses this risk assessment methodology and its adaptation for the evaluation and analysis of steam turbine inspection and overhauls.

CURRENT OUTAGE PLANNING FACTORS

An outage for turbine dismantle inspection is periodically necessary. Besides the economic considerations, many technical and reliability issues play an important role in determining the intervals for such outages. Factors currently used in making these decisions include time-based intervals, inspection history, operation, condition monitoring, and machinery design and history.

Time-based intervals

Intervals for major inspection outages may use the recommendation of the original equipment manufacturer (OEM) or calendar years with recommendations for specific inspections and normal replacement items. OEM outage intervals vary widely and may have a mysterious basis. They are usually conservative and typically do not change as technology and design improve. These methods are conservative approaches to outage interval planning. Increased competitiveness and the accompanying economic pressures are forcing industry to reevaluate the current processes that are no longer cost effective.

Inspection history

A primary means to predict the condition of a turbine is by studying past outage inspection reports. These reports may provide details on the as-found condition, damage assessments, and repairs and may define all or some future outage requirements. The data in an inspection report may be useful to determine the next outage date.

Other valuable sources of information are technical publications issued by an OEM on a class of turbine. These reports are often the result of accumulated inspection histories witnessed or reported to an OEM. They may dictate the necessity of performing an inspection or the actual outage scheduling.

Operation

The original turbine design criteria and past operation should be weighed with the unit's current and anticipated mission. Primary areas of concern include the following:

- Load characteristics: base and cycling
- Hot and cold startups
- Procedures (written or other)
- Ramping rates

Subcomponent	Corrosion	Creep	Erosion	Fretting	Fatigue	Foreign object damage	Fouling	Over-load	Rubbing/ distor-tion	Stress corrosion cracking
1st stage nozzle			x		x	x	x		x	
Blade foils	x		x		x	x	x	x	x	x
Blade roots	x	x		x	x			x	x	x
Hubs				x	x		x	x	x	
Plug			x				x		x	
Stationary diaphragms	x		x			x	x		x	x
Strainers						x	x			
Turbine split line	x		x							

II. Subset of possible failure modes and sub-components

- Over speed and unscheduled trips
- Downtime procedures
- Quality of steam.

The way a turbine currently operates may differ from its original specifications and from its previous operation. Changes in operating conditions may cause the turbine duty to be more severe or less severe. These changes may lead to decreased or increased inspection or overhaul intervals.

Condition monitoring

The availability and use of personal computers, mainframe technology, and process control and monitoring computers have allowed application of real-time condition monitoring and diagnostic tools. Monitoring, type of monitoring, and analysis of the information collected vary from turbine to turbine and company to company. Typical characteristics monitored include the following:

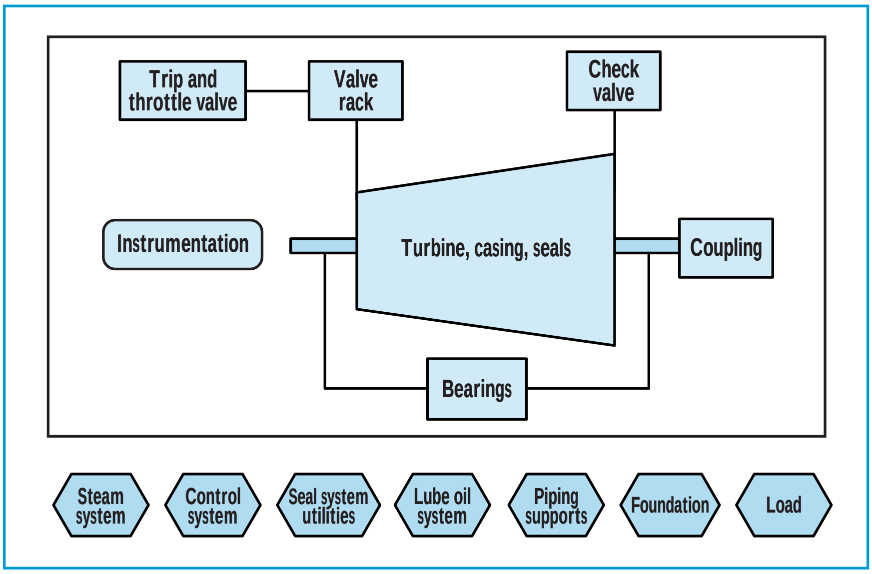
- Performance
- Vibration
- Oil and lubrication system performance
- Steam quality
- Bearing temperature.

The degree of confidence for operational and outage planning may relate directly to available diagnostics and how the information is used to improve daily operations.

Machinery design and history

In the design and history area, the primary factors are the age (vintage), operating hours, and maintenance and operating procedures for the turbine. Technologies used in the design of the turbine may have changed.

Figure 1 shows an approach to outage planning. Careful, relative weighting of these factors is necessary. Experienced machinery personnel will use information in all these areas to develop a recommendation on inspection or overhaul intervals for a steam turbine. Their recommendations use their experience and ability to integrate the available data. Often, financial considerations unfortunately may take precedence over all other factors, since they are easily



2. System definition

Category	Description	Likelihood	Frequency, incidents/year
1	Multiple failures per lifetime	1 to .1	3.0 E -01
2	Possibly multiple failures per lifetime	.1 to .01	3.0 E -02
3	Possibly occurring once in a lifetime	.01 to .001	3.0 E -03
4	Failure not likely in a lifetime	.001 to .0001	3.0 E -04
5	Failures not likely, but possible in a lifetime	.0001 to .00001	3.0 E -05
6	Failures highly unlikely, but possible in a lifetime	.00001 to .000001	3.0 E -06
7	Probability of failure essentially zero	.000001 to .0000001	3.0 E -07

III. Likelihood of failure

Subcomponent	Failure mechanism	Member #1	#2	#3	#4	#5	#6	#7	#8	Average	Standard Dev.	Median	Mode	Trimean	Minimum	Maximum
Casing	Erosion	2	3	2	2	2	2	2	2	2.10	0.35	2.0	2	2.00	2	3
Disc	Fatigue	4	5	5	2	7	6	2	4	4.38	1.77	4.5	4	4.33	2	7
Stationary diaphragms	FOD	2	2	3	2	2	1	1	-	1.66	0.69	2.0	2	1.80	1	3
Labyrinth seal-fixed	Fouling	2	2	-	5	3	5	3	-	3.33	1.37	3.0	2	3.25	2	5
Strainers	Corrosion	2	1	3	5	4	4	5	-	3.43	1.51	4.0	5	3.60	1	5

IV. Example of likelihood of failure results

Operating category	Description	Example
Outage	Failures found during an outage	Extensive diaphragm erosion discovered upon pulling casing
Test and startup	Failures during test and startup	Labyrinth seal rub during startup of a unit after an overhaul
Normal run	Failures before a pre-determined time based on inspection interval	Fatigue failure of a turbine blade shroud six months after an overhaul
Extended run	Failures that occur at an age longer than a known time-based inspection interval or longer than known history of that turbine (plant decided to run two extra years)	Fatigue failure of a blade root two years beyond the time of the past time-based inspection interval

V. Description of turbine operating categories

quantified and broadly understandable considerations.

STRAP development team goals

The primary objective of the STRAP team is to develop an effective and easy-to-use software-based tool for quantifying the risk that enables a user to develop optimum intervals between dismantle inspection outages of steam turbine components. The tool will capture and share a common experience base. It will use sound engineering principles and available data and be oriented toward operating reliability. The primary economic consequence for consideration is the cost of lost production from the time required to repair or replace a failed component.

Modern computer technology makes building a working computer model using readily-available hardware and off-the-shelf software easy. The obstacles lie in obtaining accurate and complete data on which to base the model. No single database contains all the necessary information. The STRAP development team chose to combine model building with information provided by companies and third parties. The team decided that the software tool selected must have database capabilities to allow for continuous addition of new data and improved model performance.

DEVELOPMENT PROCESS

The process to develop the outage interval model used the steps described in the ASME research report developed by a task force of experienced industry representatives. The research report is a five-volume set. Volume 1 is the general document that describes the process for "Risk Based Inspection-Development of Guidelines," and Volume 3 pertains to the fossil-fuel utility industry. The guidelines recommend a five-step process to rank or classify systems, components, or elements. The five-step process has the following:

1. System definition
2. Qualitative risk assessment
3. Quantitative risk analysis that includes failure modes, effects, and criticality analysis (FMECA) for ranking
4. Inspection program development
5. Economic optimization.

The companies of two of the authors of this paper have used this process on a project for utility steam turbines.

Turbine grouping by size and speed

Because of the design and operating variations in industry steam turbines, the first step was to segregate industrial turbines into groups. This was necessary because of the wide variety of industrial turbine applications with design and manufacturing differences that could generate categories of likelihood and consequence. **Table I** shows five categories using speed and power. No segregation of condensing and topping turbines occurred. Note the following explanation of the turbine classifications:

- Class 1a turbines may drive generators.
- Class 1b turbines may drive generators, fans, compressors, etc.
- Class 2 turbines may drive large boiler feed pumps, generators, or

large air blowers.

- Class 3 turbines may drive most compressors in industry.
- Class 4 turbines are typical of machines driving compressors in hydro-processing or hydro-treating units.
- Class 5 turbines are for API general purpose categories of drivers for pumps, air compressors, cooling water tower pumps, etc.

System definition

After identifying the turbine categories, the STRAP team developed a system definition. **Figure 2** shows the turbine system definition as a simple chart that divides the turbine into components for easy and accurate determination of risk. Some components outside the box are components or systems that are still important and may affect the calculation of risk to the turbine, but techniques outside those of the defined system will handle them.

Qualitative risk assessment

Using the defined system, the team developed failure mode matrices for each component or sub-component. Fifteen identified general failure modes were possible using the experience of the team and the literature available to them: fatigue, thermal fatigue, erosion, stress corrosion cracking, rubbing or distortion, overload, material defect, foreign object damage (FOD), wear, fretting, corrosion, electrical discharge, creep, fouling, and improper installation. The team tried to reach the lowest common denominator on the failure modes to avoid "double accounting." For example, improper installation modes would cause rubbing or distortion.

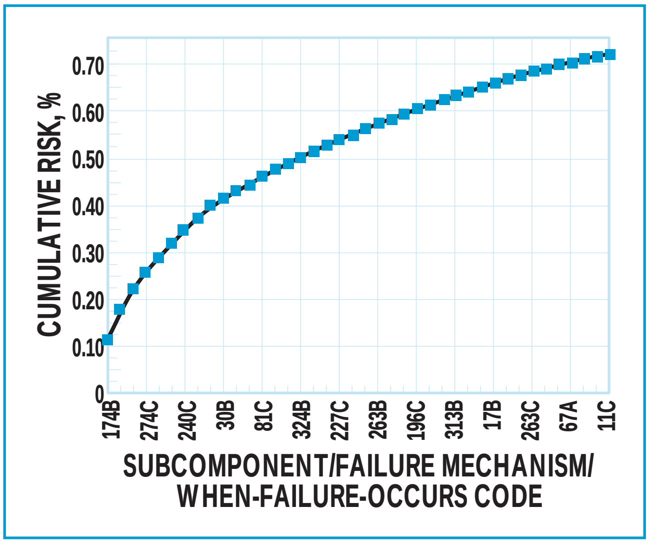
Table II shows examples of failure modes defined for some sub-components. Note that most sub-components have more than one possible failure mode.

Quantitative risk analysis

The most difficult part of the project was obtaining valid, accurate data that identified the likelihood and consequence of failure used in the analysis process. Proper calculation of component risk as a function of likelihood and consequence is critical in the ranking process. This permits identification of components or sub-components with the highest predicted risk allowing a focused effort on making the prediction of optimum time for turbine outages more manageable.

	% of total risk 50%	90%	99.9%
No. of possible failure combinations	16	98	341
No. of sub-components in a maximum of 44	12	29	44
No. of failure mechanisms in 15	6	12	15
% of failures during outage	6.3	4.1	2.3
% of failures during test and startup	37.4	33.7	35.5
% of failures during normal run	56.3	62.2	62.2

VI. Summary of failure data



3. Example of sub-components/failure mechanism vs. cumulative risk where codes refer to defined failure modes

Most reliability handbooks contain failure data for steam turbines *(6–9)* . They are incomplete because they do not include data on the sub-component level and do not have complete data on the range of turbines assessed by STRAP. To address the lack of availability of comprehensive reliability data for generating component or sub-component failure mode likelihood, the panel of experts generated baseline likelihood-and-consequence values using available machinery data, engineering judgement, and experience. These experts were individuals from three petroleum or petrochemical companies, two turbine repair companies, one insurance company, one engineering consulting firm, and one pulp and paper company.

Estimation of the likelihood—probability—of a component or sub-component failure used the categories defined in **Table III**. Twenty years was the lifetime of the turbine. For convenience, categories on a scale of 1 to 7 were translated to probabilities of .0000001 to 1 in the program internals.

A total of 336 sub-component or component failure modes were evaluated for each turbine category. After entering the failure rate data, the group analyzed and reviewed the estimated values. Data examination used four mathematical functions: the simple average, standard deviation, mode, and trimean. Mode was the most common value preferred by the team. The trimean discarded the highest and lowest values and then calculated an average of the remaining values.

The team reviewed the results to generate a single data set. For most

Sub-component	Failure mechanism	When failure occurs	Rank
Labyrinth seal fixed/ rotating	Rubbing/distortion	Test and startup	1
Casing	Erosion	Outage	2
Labyrinth seal fixed/ rotating	Rubbing/distortion	Run	3
Stator blading (reaction)	Fouling	Run	4
Rotor	Rubbing/distortion	Test and startup	5
Stationary diaphragms	Fouling	Run	6
Shroud/bands	Fatigue	Run	7
Blade foils	Fouling	Run	8
Casing	Erosion	Run	9
Blade foils	Rubbing/distortion	Test and startup	10
Tenons	Fatigue	Run	11
Bushings	Fouling	Run	12
Coupling gear teeth	Fouling	Run	13
Casing bolting	Overload	Test and startup	14
Thrust collar	Overload	Test and startup	15
Turbine split line	Improper installation	Test and startup	16

VII. Baseline risk rank of sub-components

data points, the mode and trimean were within 0.5 of each other. This indicated a strong consistency. The team decided to use the trimean except in a few cases showing large variations between trimean and mode that would require rationalization. Each of these cases was discussed individually, and the team arrived at a consensus on what value to use. Usually, these variations were the result of a few team members not having experience with a particular failure mode in their company operations. **Table IV** displays some typical results of the likelihood range.

The results show a consistency in the expert opinions with the mode and trimean being close except corrosion of strainers in the above example. Discussion revealed that some team members had experienced problems with strainers in the past and others had not. The decision was to use the trimean.

KEYWORDS

Computer programs, costs, failure, inspection, maintenance, models, risk assessment, steam turbines.

Discussion also showed that the probabilities varied depending on time or operating mode with certain failures more likely to occur during testing and startup of the turbine. Other failures might be more probably during an extended run. To accommodate this, the team adopted four operating categories: outage, test and startup, normal run, and extended run. **Table V** briefly describes each category.

The extended run probabilities increased with time past a normal run. The failures at the outage come into play only if they extend the normal outage. After considering time, more than 900 sub-component/failure mode/when-failure-occurs probabilities existed. More than 300 combinations that varied by equation for years of extended run existed. The extended run probabilities started with the normal run probabilities. Some values remained the same, some varied linearly, and some varied by a power.

Consequences

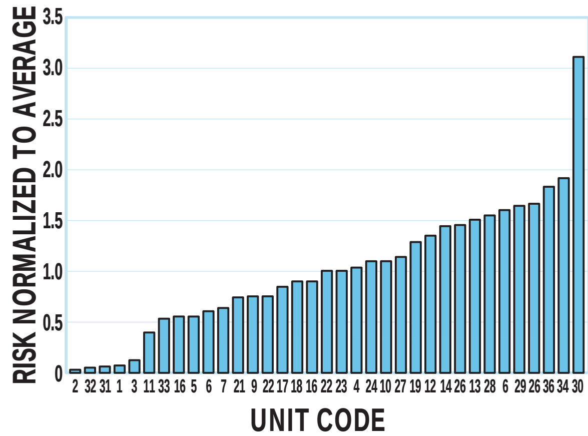
The team determined the consequences of a specific component failure using the following guidelines:

- The primary factor considered was the cost of lost production in days because of the time required to repair or replace a component.
- The time to repair or replace as used in the model starts when the equipment is handed over to maintenance. It, therefore, does not include time to bring the plant on-line or the product to specification. The team realized that the time to bring the unit down and ready for maintenance or the time required to obtain production once a repair is complete may be very significant. This is turbine dependent and handled with the economic consequences outside the model.
- The model assumed that the maximum effort is applied to repair or replace.
- If a component typically has a spare, the team assumed the spare is available and ready for installation.
- The team assumed that lost production would overshadow actual repair costs.

The days of lost production were a range with a maximum and minimum value.

Risk assessment

After determining the likelihoods and consequences, the team calculated the risk of failures of critical turbine components. Risk calculation used Eq. 1. The sub-component/failure mechanism/when-failure-occurs combinations were then sorted by decreasing risk of each combination. The top item was therefore the highest risk failure. The team reviewed this tabulation as a reality check on likelihood and consequence. Several iterations were necessary to reach a point where the volume of data "made sense." Typical issues discovered included "double dipping" of a failure mode, mixing likelihood of a failure mode with the worst possi-



4. Risk distribution of 35 low pressure utility turbines

ble consequence, and lack of consistency.

Cumulative risk was plotted and the sub-component/failure mechanism/when-failure-occurs combinations that generate the highest risk were easily identified as **Fig. 3** shows. This allowed a more focused analysis of these cumulative risk components or failure mode combinations.

Review of the data for Group 1 turbines using a 28-day outage found that 90% of the total risk comes from 98 sub-component/failure mechanism/when-failure-occurs combinations. **Table VI** shows a summary of the data.

Table VII indicates the top 16 sub-component/failure mechanism/when-failure-occurs that constitute 50% of the basic risk. The highest risk component is the labyrinth seals with rubs occurring during test and startup. Since all rankings can change for many reasons, the next step is necessary.

Loading factors

The next step in the quantitative risk assessment process is the application of loading factors that can influence a given likelihood of failure, consequence, or both. For example, the assumption made in the development of likelihood and consequence is that a spare turbine rotor is available. If a spare is not available, the consequence will increase. The program will make this adjustment via response to a question:

- Does this turbine have a spare rotor? (Yes or no)
- What is the current condition of the rotor? (Ready for immediate installation or needs normal repairs and assembly)

The factors use questions that address the turbine design and history, operation, maintenance, inspection history, past failures, spares, monitoring, etc. These factors select weighting factors that influence the likelihood of critical component failures and severity of consequence. This directly influences the total risk of the turbine and calculated time between major inspections. Additional examples of questions for developing loading factors are the following:

- Are any blades coated?
- Are the couplings lubricated with grease, lubricated continuously, dry disk, or dry diaphragm?
- Has the turbine experienced any shutdowns due to fouling?
- Is vibration monitoring periodic, continuous, or both?
- Is the turbine steam from dedicated boiler, dedicated waste heat boiler, multiple sources, or external supplier?
- Is the trip and throttle valve exercised weekly, bimonthly, monthly, quarterly, yearly, or never?

In the survey form, more than 300 possible questions—total number of questions asked depends on prior answers when filling out the survey but is typically much less than 300—and a possible 1200 answers are posed to collect information for the analysis. The program uses this data with risk and loading factors to calculate the total risk for the turbine.

Program output

Using the input data and the likelihood-consequence information, one can calculate a risk for operation of the turbine as a function of time between dismantle inspections. In each case, a quantified list of recommendations to mitigate the risk will also be reported using the greatest contribution to the risk. Inspection outage plans can then be tailored to optimize the time between overhauls using an acceptable level of risk.

Economic prioritization

The final step in any risk assessment process is to optimize the inspection interval by maximizing the net present value (NPV) of the turbine. Plans for the first draft of the current model do not include an NPV evaluation stopping with the consequence in terms of outage days. The information on the value of outage days is in the hands of the individual users. At this time, this final step will be the responsibility of those applying the modeling process.

FUTURE PLANS

Field testing of the model began in late summer of 1997 with estimated completion in six months. The model will be updated regularly to improve the accuracy of the risk assessment.

APPLICATION EXPERIENCE

Although the STRAP project has performed no risk assessments so far, the team expects that results of the beta testing will follow those obtained during the turbine output optimization project (TOOP) project for utility turbines. This developed a risk assessment tool that focused on utility turbines and generators *(10)*.

Application of that project has been in place for 1.5 years. **Figure 4** shows a plot of calculated risk. The risk assessments varied from low to high for 35 low pressure turbines.

Except a few units in the very low risk range, recommendations were generated to reduce risk. The sub-components contributing the highest portions of the overall risk were identified and ranked with recommendations made to reduce the risk for these sub-components.

STRAP will provide a similar risk ranking and recommendations to manage or reduce risk. Recommendations may be implemented immediately with the unit on-line—exercise the trip and throttle valve weekly. They might require a short 1–2-day outage that could occur when the plant is down for other reasons—installing additional monitoring. Finally they might require a major unit overhaul—upgrade a sub-component or perform a thorough nondestructive examination of certain sub-components. The software tool will permit "what if" scenarios where an engineer can extend and select the interval between dismantle overhauls using company-specific economic, operational, and technical issues. TJ

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