STEAM TURBINE RISK ASSESSMENT—A TOOL TO ASSIST IN OPTIMIZING INSPECTION AND OVERHAULS OF INDUSTRIAL STEAM TURBINES

by

Timothy J. Christ

Turbomachinery TRN Leader

Dow Chemical Company

Freeport, Texas

Michael J. Drosjack

Senior Staff Engineer

Shell Oil Products Company

Houston, Texas

and

G. Mark Tanner

Senior Engineer

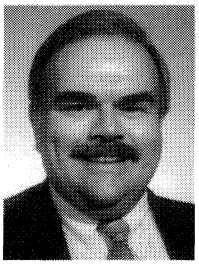
Radian International LLC

Austin, Texas

Timothy J. (Tim) Christ is the Section Manager for the Mechanical Technology Department at The Dow Chemical Company in Freeport, Texas. In this role, he leads a group of rotating equipment and refrigeration engineers and a group that follows the repair of block valves. He is also the Reliability Engineering Network Leader for Texas Operations, which is the administrative leader for approximately 50 reliability engineers in 65 units.

Mr. Christ spent most of his career managing the Critical Mechanical and Rotating Equipment groups. While he is not presently in the day-to-day turbomachinery maintenance business, he was appointed as the Leader of the Global Turbomachinery Technology Resource Network in 1996, which is a network of 13 turbomachinery experts from various global sites and is the owner of the related technology for The Dow Chemical Company.

Mr. Christ has a B.S. degree (Mechanical Engineering) from Texas A&M University (1978).



Michael J. Drosjack is a Senior Staff Engineer in the Mechanical Engineering Department of Shell Oil Products Company's Westhollow Technology Center in Houston, Texas. In this capacity, he is responsible for providing technical support for rotating and reciprocating machinery to Shell's manufacturing facilities. He is chairman of Shell's Machinery Technical Direction Team. Since joining Shell in 1975, he has had assignments on projects involving specification, evaluation, installation, and startup of machinery along with extensive field troubleshooting, particularly in the area of vibration measurement, vibration analysis, and rotordynamics.

Dr. Drosjack received his B.S. degree (Mechanical Engineering) from Carnegie-Mellon University (1970). He received his M.S. (1971) and Ph.D. (1974) degrees (Mechanical Engineering) from The Ohio State University.

Dr. Drosjack is a member of ASME and the Vibration Institute, and is a registered Professional Engineer in the State of Texas.

G. Mark Tanner is a Senior Mechanical Engineer for Radian International LLC in their Mechanical and Materials Engineering Group, in Austin, Texas. He has been with Radian for more than 10 years. He is responsible for mechanical and fitness-for-service analyses, metallurgical examinations and/or failure analyses on a variety of industrial equipment including turbines, compressors, pumps, boilers and auxiliaries, gears, fasteners, and pressure vessels. Over the past three years, Mr. Tanner's primary focus has been in the area of risk assessments.

Mr. Tanner received his B.S. degree (1984) and M.S. degree (1986) in Mechanical Engineering from Texas A&M University. He is a member of ASME, ASM International, and MPCs Fitness-for-Service Program. He is a registered Professional Engineer in the State of Texas.

ABSTRACT

There are currently no—or at best, very limited—industry guidelines or requirements on which to quantify the risk associated with turbine inspection intervals. Insurance industry data indicate that steam turbines are a major machinery loss item with underwriters. Thus, there are clear incentives to develop better tools within the industry to optimize the overhaul and inspection requirements for steam turbines.

A steam turbine risk assessment project was initiated to develop a methodology to address the issue of optimization of overhauls by identifying and quantifying the risk associated with maintenance, operation, and engineering. Furthermore, this risk is related to the economic impact of the decision.

The methodology followed is an adaptation of ASME Risk-Based Inspection Guidelines. This process, in principle, has been previously applied in the petroleum industry for pressure vessel inspection.

The process consists of five steps:

- System definition
- Qualitative risk assessment
- Quantitative risk analysis, which includes failure modes, effects, and criticality analysis (FMECA)
- Inspection program identification
- Economic optimization

The result is incorporated into a computer model that will permit scenarios for individual turbines to be evaluated on a cost-risk-benefit basis. Beta testing is scheduled to begin in third quarter 1997.

INTRODUCTION

Most machinery engineers are now used to hearing words like "the global economy, time value of money, stockholders demand for return, data driven, just in time, profit and loss statement, value added, ROI," etc. While one may not like it, these terms and the functions they represent are part of the world today. Business and accounting factors are a part of the machinery business. The impact comes from the drive to reduce the costs of operating manufacturing facilities while, at the same time, maximizing production and minimizing production interruptions (increasing availability).

One of the machinery engineer's functions where this comes to a head is in the issue of planning and justifying the maintenance overhauls of steam turbines in manufacturing facilities. An overhaul of a large turbine (greater than 20,000 hp) will have a cost of several $100,000s associated with it. The cost of not performing the overhauling in time may be a production interruption that often falls in the $100,000s to $1,000,000s range, either from an unexpected outage or extension of the turnaround to complete repairs.

There are currently no, or at best, very limited industry guidelines on which to base turbine inspection and overhaul intervals. Vendor recommendations are available but are often very conservative, without giving much consideration to the economic consequences (costs) of an extra or unnecessary inspection and overhaul. There is a trend in the industry to attempt to extend the intervals based on cost considerations.

However, the database of a major underwriter indicates that steam turbines are a major machinery loss item for underwriters [1]. Further, a recent paper indicated that significant turbine mechanical damage could occur that is not readily discernible by external inspection techniques [2]. This information indicates that there is a risk associated with inappropriate inspection and overhaul intervals, where risk is the following relationship.

$$\text{Risk} = \text{Likelihood of event} \times \text{Consequence}$$

However, while there is considerable discussion of risk, calculation of the risk with respect to inspection or overhaul intervals on turbines does not follow any well defined or agreed upon methodologies. The cost of avoiding the risk, i.e., overhaul or maintenance activities, can be calculated pretty accurately in financial terms. Determination of the cost of the consequence (losses associated with a failure) and determination of the likelihood of occurrence are more judgmental. Thus, decisions currently tend to be driven very heavily by the cost of the inspection and overhaul rather than by an assessment of the relative risk.

There is considerable interest in the industry in being better able to evaluate the combined issues of cost of inspection and overhaul and the risk of not performing these activities. ASME has developed a methodology on risk-based inspection [3, 4]. API has been active in this area, particularly in the piping and pressure equipment inspection [5]. The basic methodology incorporates "risk" that includes both an engineering and financial impact into the decision process, making it attractive for use in machinery inspection and overhaul evaluations.

Discussed herein are the risk assessment methodology and the manner in which it has been adapted for the evaluation and analysis of steam turbine inspection and overhauls.

CURRENT OUTAGE PLANNING FACTORS

There is general agreement that an outage for a turbine dismantle inspection is required periodically. Aside from the economic considerations, many reliability issues play an important role in determining the intervals at which these outages should occur. Factors that are currently utilized in making these decisions include time-based intervals, inspection history, operation, condition monitoring, and machinery design factors.

Time-Based Intervals

Time intervals for major inspection outages may be based on the recommendations of the OEM or on calendar years along with recommendations for specific inspections and normal replacement items. OEM outage intervals vary widely and may have a mysterious basis, but are usually conservative and may not change as technology and design improve over the years.

These methods are considered conservative approaches to outage interval planning. Increased competitiveness and the accompanying economic pressures are forcing industry to re-evaluate the current processes, which may no longer be cost effective.

Inspection History

A primary means of predicting the condition of a turbine is by studying past outage inspection reports. The reports may provide details on the as-found condition, damage assessments, and repairs, and may define all or part of future outage requirements. The data in the report may be the controlling document that determines the next outage date.

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

Operation

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

- Load characteristics: base and cycling
- Hot and cold startups
- Procedures (written or other)
- Ramping rates
- Overspeed and unscheduled trips
- Downtime procedures
- Quality of steam

The current operation of a turbine may differ from its original specifications and from its operation in the past. Changes in the operating conditions may cause the turbine duty to be more or less severe. This may introduce the requirement to decrease inspection or overhaul intervals or may permit increasing them.

Condition Monitoring

The availability and use of PC, mainframe technology, and process control and monitoring computers has made it possible to apply real-time condition monitoring and diagnostic tools. The

amount of monitoring, the type of monitoring, and the analysis of the information collected vary from turbine to turbine and company to company. Typical characteristics that are monitored include:

- Performance
- Vibration
- Oil and lube system performance
- Steam quality: temperature and pressure
- Hot running alignment
- Bearing temperature

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

Machinery Design/History

In the design/history area, the primary factors considered are the age (vintage), operating hours, and maintenance and revamp procedures for the turbine. Technologies utilized in the design of the turbine may depend upon the timeframe when the turbine was designed, technologies having changed over the years.

The approach to outage planning is shown in Figure 1. Careful relative weighting of these factors must be applied. Experienced machinery personnel will utilize information on all these factors in order to make a recommendation on inspection or overhaul intervals for a steam turbine. Their recommendations are based on their experience and ability to integrate the available data. Unfortunately, in many cases, financial considerations may be taking precedence over all other factors, since these are the most easily quantifiable and broadly understandable considerations.

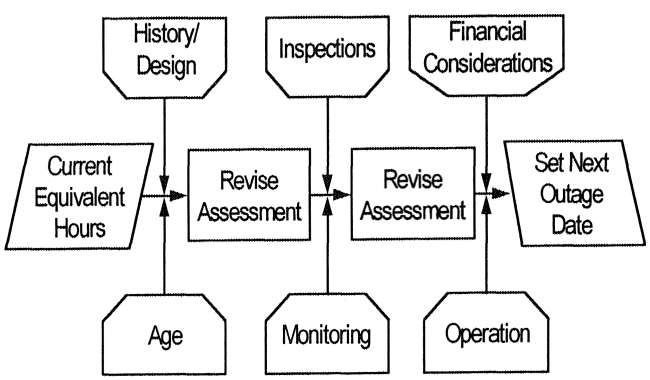


Figure 1. Outage Planning Factors.

Team Goals

The primary objective of the steam turbine risk assessment team is to develop an effective and easy-to-use software-based tool that quantifies risk to permit evaluation of optimum intervals between dismantle inspection outages of steam turbine components. This computer model will be configured to capture and share a common experience base. The contents will be based on sound engineering principles and available data and will be geared toward operating reliability. The primary economic consequence to be considered is the time required to repair/replace a failed component, which can be translated into a resultant cost of lost production.

With modern computer technology, it is relatively easy to build a working computer model using readily available hardware and off-the-shelf software. The obstacles lie in obtaining accurate and complete data on which to base the model since no single database contains all the necessary information. The team chose to combine model building with information provided by participating companies and third parties. The software tool selected must have database capabilities to allow for continuous addition of new data and improved model performance.

Development Process

The process used to develop the outage interval model is based on the steps described in the ASME research report developed by a task force of experienced industry members. The research report is a five-volume set. Volume 1 [3] is the general document that describes the process for "Risk-Based Inspection—Development of Guidelines," while Volume 3 [4] 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 includes the following:

- System definition
- Qualitative risk assessment
- Quantitative risk analysis that includes failure modes, effects, and criticality analysis (FMECA) for ranking
- Inspection program development
- Economic optimization

This process has been utilized previously 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 the industrial turbines into a number of groups. This was considered necessary, since there were a wide variety of industrial turbine applications with design and manufacture diversity that would generate categories of likelihood and consequence. Five categories based on speed and power and one subcategory were identified, as shown in Table 1. There was no segregation of condensing and topping turbines. For example:

- Class 1a turbines might be generator drives.
- Class 1b turbines might drive cracked gas compressor trains in ethylene plants.
- Class 2 turbines might drive large refinery trains like CCU air blowers or alkylation refrigeration compressors or large boiler feedpumps.
- Class 3 turbines would drive the majority of compressors in refineries or chemical plants.
- Class 4 turbines would be typical of machines driving compressors in hydroprocessing or hydrotreating units.
- Class 5 turbines would be the API general purpose category of drivers for pumps, air compressors, cooling water tower pumps, etc.

Table 1. Classification of Turbines That Will Be Analyzed by Risk Assessment Procedures.

Group	Turbine Description	Horsepower	MegaWatts	RPM	Inlet Steam Temperature
1a	Single case driver	20,000 – 100,000	14 - 70	>3,000	> 950°F
1b	Single case driver	20,000 – 100,000	14 - 70	>3,000	≤ 950°F
2	Single case driver	10,000 – 20,000	7 - 14	< 11,000	
3	Single case driver	< 10,000	< 7	< 8,000	
4	High speed backpressure	< 30,000	< 21	> 8,000	≤ 950°F
5	General purpose	< 5,000	< 3.5	< 6,000	≤ 750°F

System Definition

After the categories of turbine were identified, a system definition was developed. The turbine system definition shown in Figure 2 breaks the turbine into components and subcomponents for which risk can be more easily and accurately determined. Some

of the components in the box were then broken into subcomponents. Outside the box are components/systems that are still important and may affect the calculation of risk to the turbine, but will be handled by means outside those of the defined system.

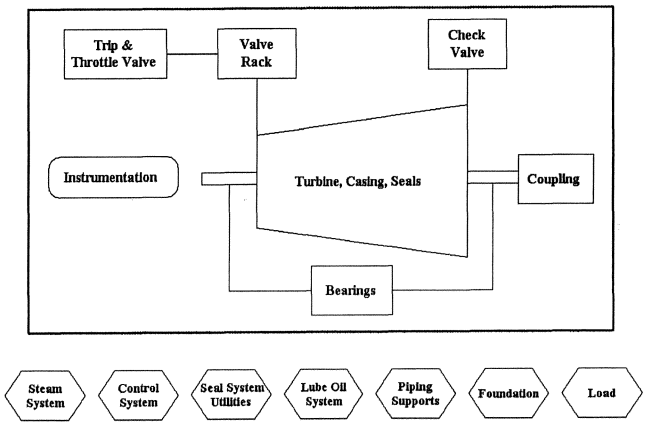


Figure 2. Chart Showing the System Definition.

Qualitative Risk Assessment

Using the system that was defined, the team developed failure mode matrices for each component/subcomponent. Fifteen possible general failure modes were identified, based on the experience of the team and the literature available to them: fatigue, thermal fatigue, erosion, stress corrosion cracking, rubbing/distortion, overload, material defect, foreign object damage, wear, fretting, corrosion, electrical discharge, creep, fouling, and improper installation. An attempt was made to reach the lowest common denominator on the failure modes to avoid "double dipping." For example, there are improper installation modes that would cause rubbing/distortion.

Failure modes defined for some of the subcomponents are shown in Table 2 as an example. Note that most of the subcomponents have more than one possible failure mode.

Table 2. Examples of Subcomponent Failure Mode Tabulation.

Subcomponent	Corrosion	Creep	Erosion	Fretting	Fatigue	FOD	Fouling	Material Defect	Overload	Rubbing/Dist.	SCC	Thermal Fatigue	Wear	Elect. Discharge	Improper Install.
1st stage nozzle			X		X	X	X	X		X		X			
Blade foils	X		X		X	X	X	X	X	X	X				
Blade roots	X	X		X	X			X	X	X	X				
Hubs				X	X		X	X	X	X			X		
Plug			X				X	X		X			X		
Rotor	X		X		X			X	X	X	X	X		X	
Stationary diaphragms	X		X			X	X	X		X	X	X			
Strainers						X	X	X							
Tenons	X		X	X	X	X		X	X	X	X				
Turbine split line	X		X					X				X			X

Quantitative Risk Analysis

The most difficult part of the project is obtaining valid, accurate data that identify the likelihood and consequence of failure to be 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 the identification of those components/subcomponents with the highest predicted risk, allowing a focused effort on making the prediction of optimum time period for turbine outages more manageable.

There are a number of reliability handbooks that contain failure data for steam turbines [6, 7, 8, 9]. However, they are not complete in that they do not have complete data on the subcomponent level, nor do they have complete data on the range of turbines being assessed by the team. In order to address the lack of availability o comprehensive reliability data to be used in generatin; component/subcomponent failure mode likelihood, the panel o experts (eight plus) generated baseline likelihood-and consequence values on the basis of their available hard data engineering judgment, and experience. The experts consist o individuals from three petroleum/petrochemical companies, tw(turbine repair companies, one insurance company, one engineerin; consulting firm, and one pulp and paper company.

Each team member estimated the likelihood (probability) of : component/subcomponent failure using the categories as define(in Table 3. Twenty years was used as the lifetime of the turbine. Fo convenience, categories on a one to seven scale were used t(represent the likelihood (probability) and were translated t(probabilities (0.0000001 to one) in the program internals.

Table 3. Definitions Used to Identify Failure Likelihood.

Category	Description	Likelihood Range	Frequency	
1	Multiple failures/Incidents per lifetime	1 to 0.1	3.0E-01	Incidents/yea
2	Possibly multiple failures/Incidents per lifetime	0.1 to 0.01	3.0E-02	Incidents/yea
3	Possibly occurring once in a lifetime	0.01 to 0.001	3.0E-03	Incidents/yea
4	Failure/Incident not likely in a lifetime	0.001 to 0.0001	3.0E-04	Incidents/yea
5	Failures/Incidents not likely, but possible in a lifetime	0.0001 to 0.00001	3.0E-05	Incidents/yea
6	Failures/Incidents highly unlikely, but possible in a lifetime	0.00001 to 0.000001	3.0E-06	Incidents/yea
7	Probability of failure/Incident essentially zero	0.000001 to 0.0000001	3.0E-07	Incidents/yea

There were a total of 332 subcomponent/component failur(modes evaluated for each turbine category. After the individua members generated their estimates or inputted their hard dat: (failure rates), the estimated values were analyzed and reviewed b; the team in order to reach group consensus. The data wer(examined using four mathematical functions: the simple average standard deviation, mode, and trimean. The mode being the mos common value selected by the team, while trimean was setup t(discard the highest and lowest value and then calculate an averag(of the remaining values. Several examples of this evaluation ar(shown in Table 4.

Table 4. Example of Team Likelihood Analysis.

Subcomponent	Failure Mech.	Tm Mem. #1	Tm Mem. #2	Tm Mem. #3	Tm Mem. #4	Tm Mem. #5	Tm Mem. #6	Tm Mem. #7	Tm Mem. #8	Average	St. Deviation	Median	Mode	Trimmean	Minimum	Maximum
Casing	erosion	2	3	2	2	2	2	2	2	2.13	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		1.86	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

The team reviewed the results in order to generate a single dat: set. For the majority of the datapoints, the mode and trimean wer(within 0.5 of each other, indicating a strong consistency of the team's opinions. It was decided that the trimean would be use(except for a few cases where there were large variations betwee trimean and mode that would have to be rationalized. Each of these was discussed on a case-by-case basis and the team came to : consensus of what value should be used. In most cases, these variations were the result of a few team members not havin; experience with a particular failure mode in their company's operation.

The results show a consistency of opinions with the mode an(trimean being close except for corrosion of strainers in the above example. After discussion, it was found that a couple of tea members had experienced problems with strainers in the past while others had not. In this case, it was decided to use the trimean

Upon discussion, it was also found that the probabilities varie(based on time or operating mode with certain failures more likel occurring during test and startup of the turbine, while others migh be during an extended run. To accommodate this, the tea extended the evaluations to consider the likelihood of up to fou

operating categories: at outage, test and startup, normal run, and extended run. Each category is briefly described in Table 5.

Table 5. Description of Operating Mode Categories.

Operating Category	Description	Example
Outage	Failures found during an outage	Extensive diaphragm erosion discovered upon pulling casing
Test & Startup	Failures during test & startup	Labyrinth seal rub during startup of a unit after an overhaul
Normal Run	Failures before a predetermined	Fatigue failure of a turbine blade time based inspection interval 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

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. Thus, after taking time into account, there were more than 900 subcomponent/failure mode/when-failure-occurs probabilities and more than 300 combinations that varied by equation for years of extended run. 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, using the following guidelines, determined the consequences of a specific component failure:

- The primary factor to be considered is the cost of lost production in days as a result of the time required to repair/replace a failed component.
- The time to repair/replace as used in the model starts when the equipment is handed over to maintenance. Thus, it does not include time to bring the plant online or product on specification. It was realized that the time to bring the unit down and ready for maintenance or the time required to get on production once a repair is complete may be very significant. However, this will be turbine dependent and can be handled with the economic consequences outside the model.
- It is assumed maximum effort is applied to the repair/replace.
- If a component is typically spared, it will be assumed a spare is available and ready to be installed.
- It was assumed that lost production would overshadow actual repair costs.

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

Risk Assessment

After the likelihood and consequences are determined, risk for failures of critical turbine components are calculated. Risk is calculated using the following relationship: Risk = likelihood × consequence. The subcomponent/failure mechanism/when-failure-occurs combinations are then sorted by decreasing risk of each combination. Thus, the top item is the highest risk failure. The team reviewed this tabulation as a reality check on likelihood and consequence. Several iterations were required to reach a point where the volume of data "made sense." Typical issues found included "double dipping" of a failure mode, mixing likelihood of a failure mode with the worst possible consequence, and lack of consistency.

Cumulative risk is then plotted and the subcomponent/failure mechanism/when-failure-occurs combinations that generate the highest risk are easily identified (Figure 3), allowing a more focused analysis on these cumulative risk components/failure mode combinations.

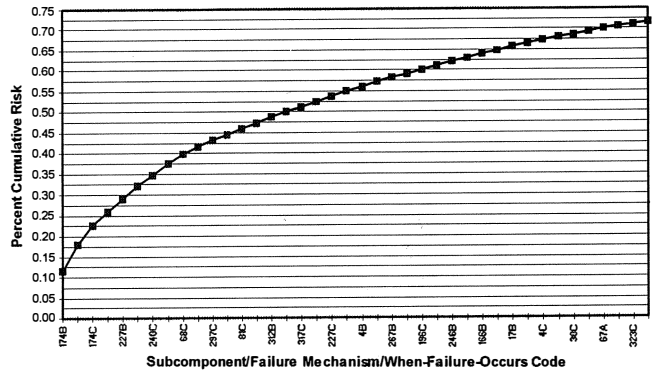


Figure 3. Example of Subcomponents/Failure Mechanism vs *Cumulative Risk. (Codes refer to defined failure modes.)*

Review of the data for Group 1 turbines using a 28-day outage, found that 90 percent of the total risk comes from 98 subcomponent/failure mechanism/when-failure-occurs combinations. A summary of those results is shown in Table 6.

Table 6. Tabulation of Failure Distribution.

	% of Total Risk		
	50%	90%	99.9%
No. of possible failure combinations	16	98	341
No. of subcomponents out a maximum of 44	12	29	44
No. of failure mechanisms out of 15	6	12	15
Percent of failures during outage	6.3%	4.1%	2.3%
Percent of failures during test and startup	37.4%	33.7%	35.5%
Percent of failures during normal run	56.3%	62.2%	62.2%

The top 16 combinations that constitute 50 percent of the basic risk are shown in the tabulation of Table 7. The highest risk component is rubs of the labyrinth seals that occur during test and startup. Rankings of relative risk can be changed by many factors, which are detailed in the next step.

Table 7. Tabulation of Top 16 Failure Modes.

Subcomponent	Failure Mechanism	When Failure Occurs	Rank
Labyrinth seal fixed/rotating	Rub./Distortion	Test & Startup	1
Casing	Erosion	Outage	2
Labyrinth seal fixed/rotating	Rub./Distortion	Run	3
Stator blading (reaction)	Fouling	Run	4
Rotor	rub./distortion	Test & Startup	5
Stationary diaphragms	Fouling	Run	6
Shroud/bands	Fatigue	Run	7
Blade foils	Fouling	Run	8
Casing	Erosion	Run	9
Blade foils	Rub./Distortion	Test & Startup	10
Tenons	Fatigue	Run	11
Bushings	Fouling	Run	12
Coupling gear teeth	Fouling	Run	13
Casing bolting	Overload	Test & Startup	14
Thrust collar	Overload	Test & Startup	15
Turbine split line	Improper instal.	Test & Startup	16

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 and/or consequence. For example, the assumption made in the development of likelihood and consequence is that a spare turbine rotor is available. If there is a situation where a spare is not available, the consequence will increase. This adjustment will be made in the program via response to a question:

- Does this turbine have a spare rotor? (Yes or No)

- Is that rotor available for immediate installation? (Yes or No)

The factors are based on questions that look at the turbine design/history, operation, maintenance, inspection history, past failures, spares, monitoring, etc. These factors are used to select weighting factors that influence the likelihood of critical component failures and severity of consequence, thus directly affecting the overall risk of the turbine and calculated time between major inspections. Additional examples of questions used to develop loading factors are:

- Are any blades coated?
- Are the couplings lubricated grease, lubricated continuous, dry disk, or dry diaphragm?
- Has the turbine experienced any shutdowns due to fouling?
- Is your vibration monitoring (periodic, continuous, both)?
- Is the turbine steam from (dedicated boiler, process or dedicated waste heat boiler, multiple sources, or external supplier)?
- Who performs maintenance on the turbine (reliability group, trained and experienced turbine plant personnel, trained and experienced supervisor with nonspecialized personnel, OEM, combination of plant and OEM, or contract personnel)?
- Is the trip and throttle valve exercised (weekly, monthly, quarterly, not exercised)?

In the survey form, more than 480 possible questions (total number of questions asked depends on prior answers when filling out the survey but is typically much less than 480) and possibly 1900 answers are posed to collect information for the analysis that can be input and stored. The model program used this input data along with the risk and loading factors to calculate the overall risk for the turbine.

Program Output

On the basis of the input data that are specific to each individual turbine, loading factors for that turbine are calculated in the model. The likelihood-consequence information that is contained in the model evaluates the particular turbine and determines the risk for operation of the turbine as a function of time between dismantle inspections. Thus, the user has a quantified risk *vs* inspection overhaul interval. In each case, the model provides a tabulation of the subcomponent/failure mode combinations that generate the risk in order of decreasing importance, i.e., greatest risk component first. In addition, a quantified list of recommendations to mitigate the risk is reported, based on the loading factors that reduce the greatest contributors to the risk. Inspection outage plans then may be tailored to optimize the time between overhauls on the basis of acceptable level of risk.

One of the particularly useful features of this type of computer model is the ability to test various strategies to mitigate or manage risk and generate quantified results that may be directly compared. This may include testing various inspection intervals, various overhaul procedures (e.g., bearing and coupling overhaul *vs* rotor changeout), various condition monitoring techniques (e.g., performance tests to validate fouling), or nonoverhaul procedures (e.g., online washing or steam system cleanup). By utilizing the model, an economic assessment of risk reduction and remaining risk may be calculated. Judgment will still be required in the final evaluation, but it may be augmented considerably by computer model predictions.

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 does 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 wil be left to those applying the modelling process due to th complexity of applying this user dependent assessment to multiuser computer model.

FUTURE PLANS

Field testing of the model will begin in the early summer o 1997, with the final version expected to be complete by the fall o 1997. The model will be updated on a regular basis witl experience to improve the accuracy of the risk assessment.

APPLICATION EXPERIENCE

Since the industrial steam turbine computer model will not b complete till the fall of 1997, there have been no risk assessment performed as of the date of preparation of this study. It is expecte that the results of the beta tests of this model will follow thos obtained with the project for utility turbines, which developed risk assessment tool that focused on utility turbine/generator greater than 60MW [10]. Applications of that computer mode have been performed for 1.5 years. A plot of calculated risk i shown in Figure 4 for those evaluations for 35 low-pressur turbines.

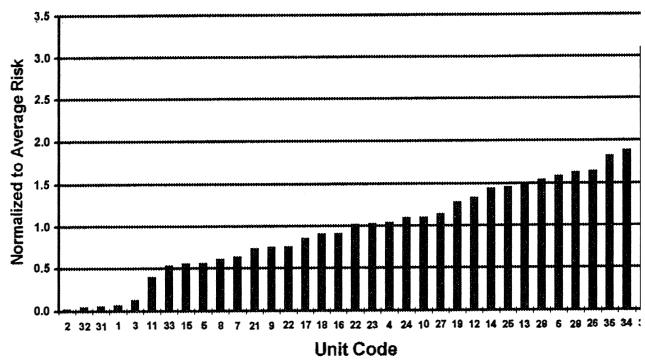


Figure 4. Risk Distribution of 35 Low Pressure Utility Turbines.

With the exception of a few units in the very low risk range, rec ommendations were generated to reduce risk. The subcomponent contributing the highest portions of the overall risk were identified ranked, and recommendations made to reduce the risks contribute by these subcomponents (Figures 5 and 6).

The utility turbine risk assessment project did not consider los production as part of its consequence, but only looked at the cos to repair/replace the failed component. In the previous case, th highest risk subcomponents for the HP turbine were blade-relate items (tenons, blade foils, and shrouds). The primary cause for th blade subcomponents to be the highest risk subcomponents wer erosion and rubbing problems. This unit was operated under partia arc steam admission, which increases the likelihood of fatigu failures.

As more turbines have been analyzed by the utility turbine risl assessment project, the risk ranking has made sense in most cases but a review of all of the data, which are in a database, showed few cases where it did not make sense. For example, supercritica pressure units were showing better risk for the LP turbines tha nonsupercritical units. It was determined that the water/stean monitoring section was giving too much risk reduction becaus these units monitor about everything that can be monitored. This i needed because, if there is an upset, it will immediately enter th turbine, while nonsupercritical units with steam drums are mor forgiving of upsets and give more reaction time to correct th problem. It was then decided that the loading factors applied to th water/steam monitoring questions should be changed to relate t operating pressure. The constant reality checks being applied to th data allow for continuing improvement of the model.

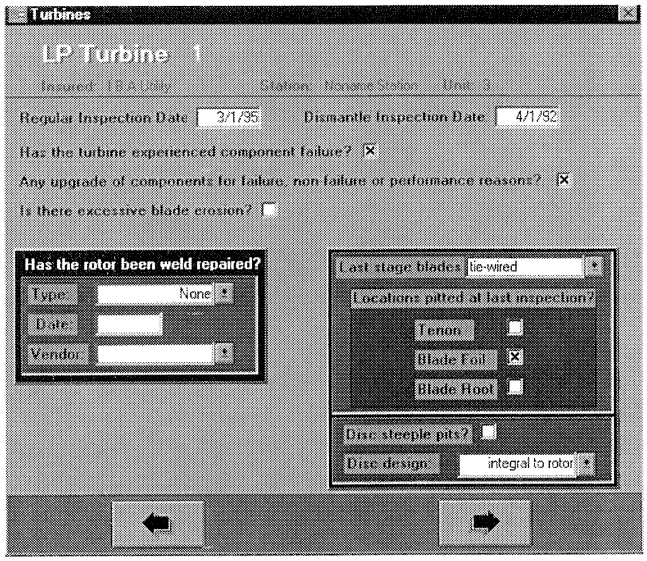


Figure 5. Screenshot of Some Questions for the LP Turbine in Utility Turbine Risk Assessment Project.

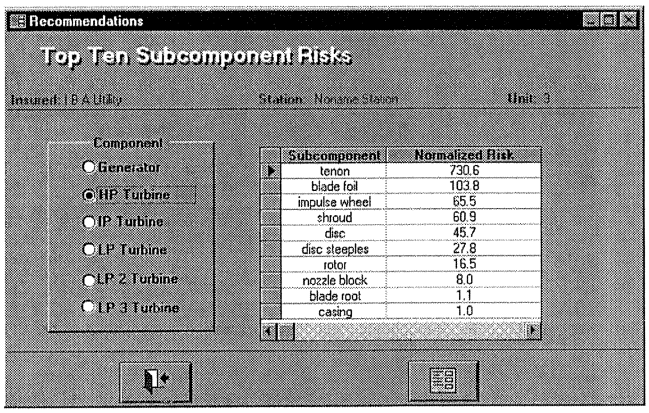


Figure 6. Screenshot Showing an Example of Risk-Ranking of the Top 10 Subcomponents in the HP Turbine in Utility Turbine Risk Assessment Project.

The industrial risk assessment project will provide similar risk ranking and recommendations to manage or reduce risk. Recommendations may be implemented immediately with the unit online (e.g., exercise the trip and throttle valve weekly), may require a short one-to-two day outage that could be implemented when the plant is down for other reasons (e.g., installing additional monitoring), or require a major unit overhaul (e.g., upgrade a subcomponent or perform a thorough nondestructive examination of certain subcomponents). The software will permit "what-if" scenarios where the interval between dismantle overhauls can be extended and selected recommendations implemented. The risk for each scenario can be compared and the optimum case selected by the engineer based on company specific economic, operational, and technical issues.

REFERENCES

1. Clark, E. E., "Rotating Equipment Loss Prevention—An Insurer's Viewpoint," *Proceedings of the Twenty-fifth Turbomachinery Symposium*, Turbomachinery Laboratory, Texas A&M University, College Station, Texas, pp. 103-122 (1996).
2. Johns, D. A. and Bertucci, J. C., "Turbine Overhaul Frequency: Time or Performance Based?" *Proceedings of the Twenty-fifth Turbomachinery Symposium*, Turbomachinery Laboratory, Texas A&M University, College Station, Texas, pp. 123-132 (1996).
3. ASME Research Report CRTD, *20* (1), "Risk Based Inspection—Development of Guidelines, Volume 1, General Document," The American Society of Mechanical Engineers, New York, New York, (1991).
4. ASME Research Report CRTD, *20* (3), "Risk Based Inspection—Development of Guidelines, Volume 3, Fossil Fuel-Fired Electric Power Generating Station Applications," The American Society of Mechanical Engineers, New York, New York, (1994).
5. API Publication 581, Base Resource Document—Risk-Based Inspection, Preliminary Draft First Edition, American Petroleum Institute, New York, New York (June 1996).
6. *Guidelines for Process Equipment Reliability Data with Data Tables*, Center for Chemical Process Safety, American Institute of Chemical Engineers, New York, New York (1989).
7. *Offshore Reliability Data, Second Edition*, Det Norske Veritas Industri Norge as DNV Technica.
8. *Failure Mode/Mechanism Distributions*, Reliability Analysis Center, Department of Defense, Washington, D.C. (1991).
9. *Nonelectronic Parts Reliability Data*, Reliability Analysis Center, Department of Defense, Washington, D.C. (1995).
10. Sipos, S., Tarbet, M., and Takacs, L., "*Optimizing the Interval for Turbine Generation Inspection Outage*," ASME International Power Conference, Houston, Texas (October 1996).