Risk-based Machinery Management

API RECOMMENDED PRACTICE 691
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Suggested revisions are invited and should be submitted to the Standards Department, API, 1220 L Street, NW, Washington, DC 20005, standards@api.org.

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Introduction

The origins for the development of this recommended practice came from the recognition among responsible companies that more effective machinery risk management requirements are needed in view of:

— major accidents occurring within the industry;

— new manufacturing centers having difficulty in consistently achieving acceptable levels of quality;

— new applications and services that involve unproven design envelopes;

— larger fleets of aging machinery operating in process and pipeline facilities;

— limited experienced resources operating and maintaining machinery.

These and other drivers have influenced the content of the pages that follow, including understanding of the following.

1) Machinery risk is context dependent. It may be quite different among companies operating identical machinery within the same process service. Therefore, to be truly effective, the API Subcommittee on Mechanical Equipment (SOME) determined that prescriptive design requirements, as seen in machinery base standards, such as API 610, could not be imposed upon the industry by API 691. Since every company has unique engineering specifications, process requirements, worker competencies, work processes, risk tolerances, etc., API 691 allows internal risk criteria and methodologies to be utilized by individual operating companies for the purpose of identifying and managing high-risk machinery applications within the context of their own operating regimes.

2) Machinery risk is systemic. As such, the recommended practice sets minimum requirements for operating companies, selected designated responsible parties (DRPs), and vendors. Depending on the companies within this system, risk levels may either rise or fall for any given machinery asset. Each company is encouraged to map the API 691 processes outlined herein to their internal work process to the extent possible. The vendor is required to maintain on file design failure mode and effects analysis (DFMEA) as specified by the operating company. They are also responsible to track the technology readiness levels (TRL < 7) of components and subcomponents whose failure may lead to a loss of containment and/or a loss of functionality that could lead to a potential process safety event and to define integrity operating window (IOW) as required. Any other risk management requirement placed upon the vendor is considered outside the scope of this recommended practice. The DRP is required to perform all tasks and activities required by the operating company to enable safe and environmentally compliant machinery.

3) Machinery risk is dynamic. It changes over time and, therefore, API 691 is organized by machinery life cycle phase, including feasibility and concept selection; front end engineering design; detailed design; installation and commissioning, and operations and maintenance. There are periodic risk assessments that are required in each of these phases. The recommended practice requires the operating company to put in place a management system to track and mitigate risks where required over time, develop machinery standard operating procedures, define safe operating limits (SOLs), and provide adequate training for operating and maintenance personnel working on high-risk machinery, hereafter referred to as “API 691 Machinery.”

While not required, the user of this recommended practice is encouraged to utilize the Informative annexes where internal requirements are either lacking or found to be insufficient. The operating company and/or their DRP will find that issuing both the base API machinery datasheet (e.g. the API 618 datasheet) concurrently with the API 691 data sheet (Annex H) at the proposal stage is a useful way to define and communicate all API 691 requirements to ensure these are properly addressed and in the most timely manner.

A bullet (●) at the beginning of a section or subsection indicates that either a decision is required or further information is to be provided by the operating company. When such decisions and actions are taken, they may be specified in company documents (e.g. requisitions, change orders, datasheets, and drawings).

Risk-based Machinery Management

1 Scope

1.1 General

1.1.1 This recommended practice defines the minimum requirements for the management of health, safety, and environmental (HSE) risks across the machinery life cycle. It shall be applied to the subset of operating company and/or vendor defined high-risk machinery.

1.1.2 Unless otherwise specified, the following criteria shall be used for initial risk screening to identify potential high-risk machinery for which this recommended practice will be applied:

a) hazardous gas or liquid services as defined by jurisdiction, appropriate regulatory body, and/or operating company standards or specifications,

b) services operating at temperatures >350 °F (177 °C) and having design or specified off design operating pressures >80 % maximum allowable working pressure (MAWP),

c) services operating at temperatures >400 °F (204 °C),

d) components and subcomponents having technology readiness levels (TRLs) < 7 whose failure may lead to a loss of containment and/or a loss of functionality that could lead to a potential process safety event (see Table 1),

e) liquid services operating at pressures in excess of 600 psig (41.4 bar),

f) liquid services having specific gravities less than 0.5.

It is acknowledged that most operating companies and vendors may have existing risk management processes. This recommended practice is not written to replace or invalidate company practices but is meant to supplement them to provide safe working and living environments for facilities and surrounding communities. Operating companies (i.e. Sections 5, 6, 7, and 8 for design, installation, and operating purposes) or vendors [i.e. in Section 4 for research and development (R&D) and product development purposes] can use their own initial risk screening criteria where these have been found to be effective or the criteria recommended above.

NOTE 1 Typically only between 10 % and 20 % of machinery falling within any given initial risk screening will be considered API 691 Machinery. This can include a subset of “critical,” “unspared,” “special purpose,” “prototype,” and/or worst actor machinery. Risks can include loss of containment of hazardous fluids, loss of functionality, high energy releases, etc.

NOTE 2 Applicable international (e.g. GHS [1]) or national (e.g. OSHA 1910.119, API 570 [2], Class 1, etc.) hazardous service classifications are typically defined within operating company specifications.

NOTE 3 Operating companies and vendors can choose to apply this recommended practice to machinery not covered by existing API standards (e.g. hyper compressors).

1.1.3 The following machinery protection and safety standards shall be applied to new API 691 Machinery where applicable:

a) API 670;

b) IEC 61508-1, IEC 61508-2, and IEC 61508-3;

c) IEC 61511 (Parts 1, 2, and 3) or ANSI/ISA-84.00-2004 (Mod IEC 61511);

d) IEC 62061 or ISO 13849-1 and ISO 13849-2.

1.1.4 Other standards and technical reports may be used to further assist in the application of this standard including:

a) ISO 12100, [3]

b) ISO/TR 14121, [4]

c) VDMA 4315, [5]

d) IEC 60812, [6]

e) IEC 64244-3. [7]

1.1.5 This recommended practice is intended to be used by operating companies, their designated responsible parties (DRP), and vendors that are identified as potentially operating at high risk. It is applicable to both new (Sections 4 to 8) and existing (Section 8) installations.

NOTE This can include some supporting process equipment, for example, knockout drums, instrumentation, etc. that are located off-skid.

1.2 Machinery Risk Management

1.2.1 General

The term “API 691 Machinery” is used in this recommended practice to identify machinery that warrants a comprehensive machinery risk management system. Using risk ranking to prioritize machinery for further study and/or action provides a focus that maximizes the risk reduction of ongoing activities and improves the effectiveness of machinery risk management systems.

1.2.2 Management System

A management system to implement and sustain risk management programs for machinery should include:

1) procedures covering implementation, program maintenance, and reassessment (including reassessment triggers),

2) roles/responsibilities, training, and competence testing to ensure employment of qualified personnel,

3) documentation requirements of the risk analyses (e.g. scope, boundaries, assumptions, and mitigation actions),

4) data requirements including validation requirements,

5) acceptable risk limits and thresholds,

6) management of change (MOC) process,

7) program audit traceability requirements.

1.2.3 Risk Assessments

Assessment of probability and consequence can be done by a variety of approaches at the operating company or vendor’s option. Refer to Annex A for further information. This recommended practice allows flexibility in assessment approaches (various qualitative, semi-quantitative, or quantitative methods) and defines only the deliverables needed at each stage to determine appropriate mitigations.

1.2.4 Risk Mitigation

Risk mitigation is typically accomplished by:

a) identifying risk levels above owner-defined limits,

b) identifying both the probability of failure (POF) and consequence of failure (COF) to understand the risk drivers,

c) identifying scenarios in sufficient detail to provide the specified deliverables at each life cycle stage,

d) identifying potential mitigations for either or both probability and consequence,

e) selecting and testing mitigations for sufficient risk reduction,

f) documenting and implementing the selected mitigations.

NOTE All of the steps above may not be appropriate at every life cycle stage.

1.2.5 Integration with Other Risk Assessments

The risk assessment methodologies within this recommended practice encompass approaches that enhance those conducted as part of a typical process hazard analysis (PHA) or reliability centered maintenance (RCM) program, both of which tend to focus on only a portion of the equipment life cycle. Integration of the various methodologies across the machinery life cycle (and its organizational supply chain) is key to a successful machinery risk management program.

Operating companies or their designated responsible party (DRP) may perform initial screening of machinery as part of routine process safety management (PSM) and/or hazard and operability (HAZOP) studies. These may also be useful in providing information on risk (e.g. consequence and/or operating scenarios).

1.2.6 Risk Assessment and Mitigation Activities by Life Cycle Stage

1.2.6.1 General

Risk assessment is used at different stages of the life cycle in different ways. These typically include two stages: a screening to identify machinery warranting further review and a more detailed assessment to identify needed mitigation.

For screening assessments, consequence alone may be used to trigger the need for further, more detailed risk assessments (e.g. better screening and evaluate risk management activities).

The following outlines the risk assessment and mitigation activities at each of the life cycle phases. It should be noted that API 691 Machinery can be declassified at any phase by the operating company if it is deemed that machinery or machinery components and subcomponents are not considered high risk and do not require mitigation.

1.2.6.2 Feasibility and Concept Selection (Section 4)

A screening assessment is performed early to identify machinery with potential high risks principally in the research, development, new applications, or manufacturing activities. Technical risk categorization (TRC) and technical readiness level (TRL) assessments aid in risk assessment and the definition and application of mitigation in this phase.

1.2.6.3 Front-end Engineering Design (FEED) (Section 5)

A preliminary risk assessment is performed in this stage to:

a) identify API 691 Machinery with potential high risks,

b) define a list of supplementary protective measures that should be within the scope for detailed design.

1.2.6.4 Detailed Design (Section 6)

A more detailed risk assessment with the additional information available as design progresses (or as changes occur) is performed in this stage to:

a) confirm that the risk level is high enough to warrant continued mitigation,

b) define available mitigations in design or in operation and maintenance activities.

NOTE These would typically include detail to the maintainable item level for failure mode and effects analysis (FMEA) and task selection.

1.2.6.5 Installation and Commissioning (Section 7)

This section covers requirements, recommendations, and considerations for the installation and commissioning phase including:

a) use of API 686 [8],

b) recommendations on the review of deviations in the process and/or the machinery,

c) recommendations on the verification of mitigations (including functional safety tests),

d) recommendations and considerations on commissioning operational tests,

e) pre-start-up safety reviews (PSSRs),

f) installation and commissioning documentation.

1.2.6.6 Operation and Maintenance (Section 8)

An initial screen is performed to identify API 691 Machinery leveraging available HAZOPs, incident reports, and other HSE related documentation. A field risk assessment is then conducted for machinery found to meet specific criteria defined within the recommended practice. The results of the field risk assessment should provide actionable mitigation activities that, after technical review, are required to be implemented per this recommended practice.

1.2.6.7 Guidelines for Risk Assessment Methodology (Annex A)

Annex A (informative) provides detailed background information and guidance on risk assessment and management methodologies.

1.3 Limitations

This recommended practice is based on machinery risk assessment methodologies commonly used within the petroleum, chemical, and gas industries.

Nonetheless, it will not compensate for:

a) inaccurate or missing information,

b) inadequate designs or faulty equipment installation,

c) operating outside defined and acceptable limits,

d) not effectively executing defined equipment activities,

e) not employing or improper utilization of competent personnel,

f) not applying good teamwork and/or communication principles,

g) lack of utilizing recognized and generally accepted good engineering practice (RAGAGEP),

h) not applying sound operational judgment,

i) poor repair practices (e.g. materials, parts, workmanship),

j) unknown or unidentified damage mechanisms,

k) sabotage.

1.4 Work Process Overview

The recommended practice covers potential risk mitigation activities in the complete life cycle of the machinery, and as such it is organized for the sequential execution from the feasibility and concept selection phase of new facilities through the end of operations. Application to existing machinery installations is covered in Section 8. Figure 1 outlines the major work process steps and shows the starting points for both new and existing machinery.

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Recommended Practice 1FSC, *Facilities Systems Completion Planning and Execution*

API Specification Q1, *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry*

API 510, *Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair, and Alteration*

API Standard 541, *Form-wound Squirrel Cage Induction Motors—375 kW (500 Horsepower) and Larger*

API Standard 546, *Brushless Synchronous Machines—500 kVA and Larger*

API Standard 547, *General-purpose Form-wound Squirrel Cage Induction Motors—250 Horsepower and Larger*

API Recommended Practice 571*, Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*

API Recommended Practice 576, *Inspection of Pressure-relieving Devices*

API Recommended Practice 584, *Integrity Operating Windows*

API Standard 600, *Steel Gate Valves—Flanged and Butt-welding Ends, Bolted Bonnets*

API Standard 610, *Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries*

API Standard 611, *General Purpose Steam Turbines for Petroleum, Chemical, and Gas Industry Services*

API Standard 612, *Petroleum, Petrochemical, and Natural Gas Industries—Steam Turbines—Special-purpose Applications*

API Standard 613, *Special Purpose Gear Units for Petroleum, Chemical and Gas Industry Services*

API Standard 614, *Lubrication, Shaft-sealing and Oil-control Systems and Auxiliaries*

API Standard 616, *Gas Turbines for the Petroleum, Chemical, and Gas Industry Services*

API Standard 617, *Axial and Centrifugal Compressors and Expander-compressors*

API Standard 689, *Collection and Exchange of Reliability and Maintenance Data for Equipment*

API Standard 618, *Reciprocating Compressors for Petroleum, Chemical and Gas Industry Services*

API Standard 619, *Rotary-type Positive Displacement Compressors for Petroleum, Petrochemical and Natural Gas Industries*

API Standard 670, *Machinery Protection Systems*

API Standard 676, *Positive Displacement Pumps—Rotary*

API Standard 677, *General-purpose Gear Units for Petroleum, Chemical and Gas Industry Services*

API Standard 682, *Pumps—Shaft Sealing Systems for Centrifugal and Rotary Pumps*

API Standard 692, *Dry Gas Sealing Systems for Axial, Centrifugal, Rotary Screw Compressors and Expanders*

ANSI [1]/ISA [2]-84.00-2004 (Mod IEC [3] 61511), *Functional safety—Safety instrumented systems for the process industry sector (Parts 1, 2, and 3)*

IEC 61508 *Functional safety of electrical/electronic/programmable electronic safety-related systems (Parts 1, 2, and 3)*

IEC 61511, *Functional safety—Safety instrumented systems for the process industry sector (Parts 1, 2, and 3)*

IEC 62061, *Safety of machinery—Functional safety of safety-related electrical, electronic and programmable electronic control systems*

ISO 13849-1 [4], *Safety of machinery—Safety-related parts of control systems—Part 1: General principles for design*

ISO 13849-2, *Safety of machinery—Safety-related parts of control systems—Part 2: Validation*

ISO 20815, *Petroleum, petrochemical and natural gas industries—Production assurance and reliability management*

OSHA 1910.119 [5], *Process safety management of highly hazardous chemicals*

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1 American National Standards Institute, 25 West 43rd Street, 4th Floor, New York, New York 10036, www.ansi.org.

2 The International Society of Automation, 67 T.W. Alexander Drive, Research Triangle Park, North Carolina, 22709, www.isa.org.

3 International Electrotechnical Commission, 3, rue de Varembé, 1st Floor, PO Box 131, CH-1211 Geneva 20, Switzerland, www.iec.ch.

4 International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, www.iso.org.

5 U.S. Department of Labor, Occupational Safety and Health Administration, 200 Constitution Avenue NW, Washington, DC 20210, www.osha.gov.

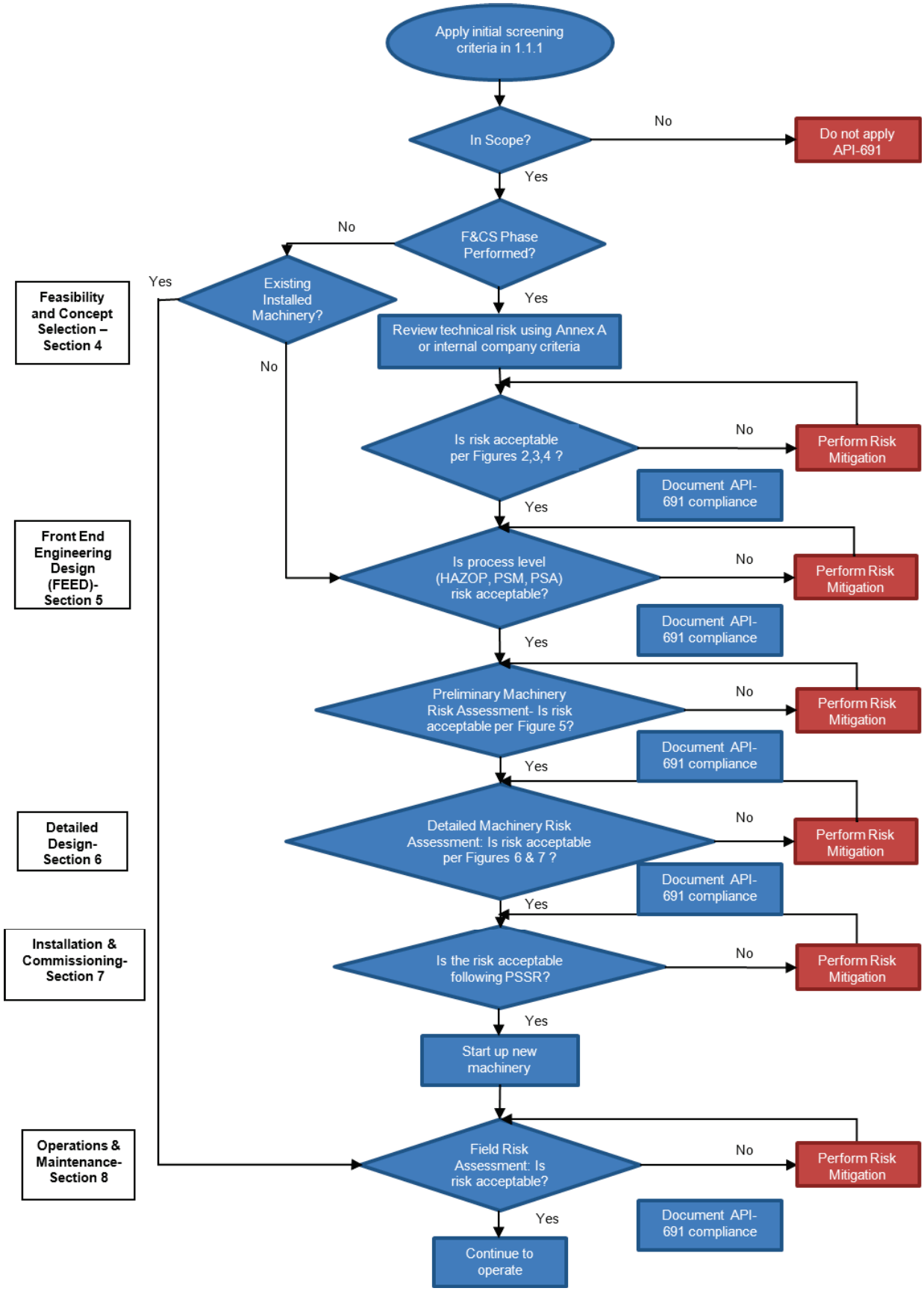


Figure 1—API 691 Work Process Overview

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1
anomaly
A state or transient that is a deviation from understood normality, which may or may not be indicative of failure.

3.1.2
API 691 Machinery
API machinery and their auxiliaries falling in the scope of API 691 that have been assessed to be of potentially high risk at any phase in the equipment life cycle.

3.1.3
availability
The ability of an item to be in a state to perform a required function in a defined operating context at a given instant of time, or on average over a given time interval, assuming that the required external resources are provided.

NOTE High availability can be achieved through high reliability (equipment rarely breaks down) or improved maintainability (when equipment breaks down it is repaired quickly), or a combination of both.

3.1.4
availability requirements
Appropriate combination of reliability and/or maintainability performance characteristics that need to be achieved to meet project requirements.

3.1.5
condition-based tasks
Preventive maintenance (PM) tasks driven by condition rather than time. The periodicity of “sampling” condition is determined by the potential failure (P-F) interval that sets the time base for the task.

3.1.6
condition monitoring
CM
The process of monitoring condition indicators in machinery (vibration, temperature, etc.), in order to identify a significant change that is indicative of a developing fault.

NOTE Condition indicators can be inferred through age, usage, cyclic accumulation, and sensors of physical condition (including the direct effects of failure) or measurements of performance that infer condition.

3.1.7
condition monitoring tasks
CM tasks
CM activities conducted to monitor data from assets to detect the onset of failure, determine condition, detect exceedance, and calculate prognostics to help decide the most opportune time to conduct condition-based preventative maintenance tasks.

3.1.8
corrective action
An action carried out after fault recognition that is intended to restore the condition to a nominal state.

3.1.9
corrosion
The gradual dissipation of metallic surfaces as the result of oxidation or other chemical reaction.

3.1.10
downtime
The time interval during which an item is unable to perform a required function due to a fault, or other activities, e.g. during maintenance.

3.1.11
equipment unit
Specific equipment unit within an equipment class as defined by its boundary (e.g. one pump).

3.1.12
erosion
Loss of material, or degradation of surface quality, through friction or abrasion from moving fluids, cavitation, or by particle impingements.

3.1.13
failure
Termination of the ability of an item to perform a required function.

NOTE 1 After failure initiation, the item has a fault.

NOTE 2 “Failure” is an event, as distinguished from “fault,” which is a state.

NOTE 3 See also related definition for functional failure.

3.1.14
failure cause
Circumstances associated with the machine’s environment, design, manufacture, installation, operation, and maintenance that have, or may, lead to a failure.

NOTE In the process of isolating a failure cause, each cause may have an effect, and each effect has causes, so the relationship is iterative.

3.1.15
failure data
Data characterizing the occurrence of a failure event.

NOTE Failure data can be plural in that many occurrences along with age at failure can be used to characterize the failure probability distribution.

3.1.16
failure effect
The consequence of a failure mode (e.g. loss of function, impact on safety, the environment, operational capability).

3.1.17
failure finding task
FF task
A routine maintenance task, normally an inspection or testing task, designed to determine whether an item or component has failed, where the failed state may not be apparent to the operating or maintenance crew undertaking their normal duties.

NOTE A failure finding (FF) task should not be confused with an on-condition task, which is intended to determine whether an item is about to fail. FF tasks are sometimes referred to as functional tests.

3.1.18
failure mechanism
A process (physical, chemical, human, or other) that leads to a failure.

NOTE Most failure mechanisms involve more than one process and occur as a chain of events and processes.

3.1.19
failure mode
The effect by which a failure is observed on the failed item (i.e. the loss of a required functionality, e.g. loss of containment).

3.1.20
fault
State of an item characterized by inability to perform a required function, excluding such inability during PM or other planned actions, or due to lack of external resources.

3.1.21
frequency
a) Frequency is the number of occurrences of a specified event or class of events per unit time.

b) The ratio of the number of times an event occurs in a series of trials of a chance experiment relative to the number of trials of the experiment performed.

Definition b) is equivalent to the definition of probability. In this recommended practice, Definition a) will be assumed wherever the term frequency is used, unless otherwise stated.

3.1.22
function
The intended purpose of an item to perform a specific task or capability in a defined operating context by asset stakeholders.

3.1.23
functional failure
A state in which an asset or system is unable to perform a specific function to a level of performance that is acceptable to its stakeholders.

3.1.24
functional test
FF task that involves testing of equipment or protective device functionality whose failure would otherwise be hidden to the operating and maintenance crew undertaking their normal duties.

3.1.25
harsh service
An inhospitable environment that can accelerate machinery degradation or affect performance.

3.1.26
hazard
Danger to personnel or the environment arising from an unplanned event such as a failure, fault, or accident.

3.1.27
hidden failure
Failure that is not immediately evident to operations and maintenance personnel undertaking their normal duties.

NOTE Equipment that fails to perform an “on-demand” function falls into this category. It is necessary that such failures be detected to be revealed.

3.1.28
human error
Human action or inaction that produces an unintended result, where the result is detrimental.

3.1.29
incipient failure
The early stages of a failure where the condition has not yet degraded to a point where stakeholder functions are not being met.

3.1.30
indenture level
A level of subdivision in any hierarchical representation of a system or object, indicating components that make up the whole. The hierarchies may refer to maintenance, physical equipment, organizations, etc.

3.1.31
integrity
The ability of a system of components to perform its required function while preventing or mitigating incidents that could pose a significant threat to life, health, and the environment over its operating life.

3.1.32
integrity operating window
IOW
Established limits for process variables (parameters) that can detrimentally affect the integrity of the equipment if the process operation deviates from the established limits for a predetermined amount of time (includes critical, standard, and informational IOWs).

3.1.33
intrusive preventative maintenance tasks
Time-based preventative maintenance tasks that require replacement of parts or disassembly to perform refurbishment or detailed inspection.

3.1.34
life cycle
The entire useful life of a product or service, usually divided into sequential phases, which include design, development, build, operate, maintain, and disposal (or termination).

3.1.35
loss of containment
An unplanned or uncontrolled release of any material from containment, including nontoxic and nonflammable materials (e.g., steam, hot condensate, nitrogen, compressed CO_2, or compressed air).

3.1.36
maintainability
Ability of an item under given conditions of use to be retained in, or restored to, a state in which it can perform a required function, when maintenance is performed under given conditions and using stated procedures and resources.

3.1.37
maintainable item
Item that constitutes a part or an assembly of parts that is normally the lowest level in the equipment hierarchy indenture level during maintenance.

3.1.38
maintenance
Combination of all technical and administrative actions, including supervisory actions, intended to retain an item in, or restore it to, a state in which it can perform a required function in a defined operating context, required by its stakeholders.

3.1.39
management of change
MOC
The process of bringing planned change to an organization or set of physical assets. MOC usually means leading an organization through a series of steps to meet a defined goal. Synonymous with change management.

3.1.40
mitigated risk
A risk for which the probability and/or consequences have been either eliminated or minimized to an acceptable level.

3.1.41
nonintrusive tasks
Time-based PM tasks not requiring process or asset interruption, equipment shutdown, tag out, entry, or disassembly.

NOTE PM tasks typically reduce the likelihood of failure, but do not require significant replacement of parts, disassembly, or otherwise cause reintroduction of infant mortality failure risk.

3.1.42
operational tests
FF tasks that involve start-up and running of equipment to verify both initial ability to operate and long-term ability to continue to perform its function over a desired mission time.

NOTE Operational tests include cut in tests where redundant or spared equipment are checked to cut in and run as full duty equipment (i.e. routine equipment swapping).

3.1.43
overhaul
A comprehensive examination and restoration of an asset to an acceptable condition.

3.1.44
package
A named system, subsystem, or defined set of components considered as a single entity for the purposes of a design study or for procurement (e.g. subsea tree, control system).

3.1.45
predictive tasks
The analysis and trending of data obtained from CM tasks, so that the future ability of equipment to perform its desired function can be analyzed and predicted.

3.1.46
preventive maintenance
PM
Maintenance carried out at predetermined intervals or according to prescribed criteria with the intention to preserve the functions required of physical assets in a defined operating context by their stakeholders.

NOTE PM can have the effect of reducing the POF or the degradation of the functioning of an item.

3.1.47
probability
A number expressing the likelihood that a specific event will occur. It is usually expressed as the ratio of the number of actual occurrences to the number of possible occurrences.

3.1.48
process
An arrangement of tasks directed toward a specific objective.

3.1.49
qualification
The process of confirming, by examination and provision of evidence, that equipment meets specified requirements for the intended use.

3.1.50
redundancy
Existence of more than one means for performing a required function of an item.

3.1.51
reliability
The ability of an item to perform a required function under a defined operating context for a required time interval.

3.1.52
reliability and maintainability data
RM data
Data collected to support analysis of reliability, maintainability, and availability.

NOTE Reliability and maintainability (RM) data is the term applied by ISO 14224. ISO 20815 refers to reliability data instead.

3.1.53
reliability, availability, and maintainability analysis
RAM analysis, RAM-1 and RAM-2
Reliability, availability, and maintainability (RAM) analysis is the examination of equipment reliability, maintainability, and availability data to determine the optimum operation and maintenance strategies. RAM-1 is the initial analysis performed during the FEED stage and is focused at the system or process level. RAM-2 is the analysis performed during the detailed design stage and is used to validate the results of the RAM-1 analysis at the equipment level.

3.1.54
risk
The combination of the probability of some event occurring during a time period of interest and the consequence (generally negative) associated with the event.

NOTE Risk can be measured in several ways, e.g. as the probability of occurrence of an unwanted event during a given time or as the product of the frequency of occurrence of an adverse event and a numeric measure of the consequences of the event.

3.1.55
risk assessment
The determination of whether identified risks are acceptable or not.

3.1.56
risk category
A specific way to group risks under a common area, which provides a structured and systematic approach in identifying risks to a consistent level of detail.

3.1.57
risk mitigation
Process of selection and implementation of measures to modify risk. The term risk mitigation is sometimes used for measures themselves. Also called risk mitigating strategy.

3.1.58
risk priority number
RPN
A technique used for analyzing the risk associated with potential problems identified during an FMEA. Risk priority number (RPN) utilizes the following three rating scales.

a) *Severity*—rates the severity of the potential effect of the failure.

b) *Occurrence*—rates the likelihood that the failure will occur.

c) *Detection*—rates the likelihood that the problem will be detected before the loss of stakeholder functions occur.

RPN = severity × occurrence × detection

3.1.59
safe operating limit
SOL
The value(s) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure safe operation.

3.1.60
specification
The document in which functional, performance, design, and operating requirements are defined.

3.1.61
surveillance tasks
SV tasks
CM tasks that involve monitoring indications or other parameters or conditions to compare to established acceptance criteria.

NOTE Surveillance (SV) tasks are mainly manual and sometimes invasive. Includes operators conducting zonal checks.

3.1.62
technical risk
Risk associated with the achievement of a technical goal, criterion, or objective. It applies to the probability of and undesired consequences related to technical performance, human safety, mission assets, or environment.

3.1.63
turnaround
A scheduled shutdown of equipment, production lines, or process units to clean, change out components, make repairs, and if necessary, carry out capital projects.

3.1.64
uncertainty
A state of having limited knowledge where it is difficult or impossible to exactly describe the existing state or predict future outcome(s). [9]

3.1.65
validation
The process that substantiates whether technical data and engineering models are within the required range of accuracy, consistent with the intended application.

3.1.66
verification
The process that determines the extent to which a procedure, task, physical product, or model conforms to its specification.

3.2 Acronyms and Abbreviations

ALARP	as low as reasonably possible
APV	availability probability value
BAT	best available technology
CBM	condition-based maintenance
CFD	computational fluid dynamic
CM	condition monitoring

CMMS	computerized maintenance management system
COF	consequence of failure
DFMEA	design failure mode and effects analysis
DRP	designated responsible party (e.g. engineering contractors, consultants, etc.)
EAM	enterprise asset management
FEA	finite element analysis
FEED	front-end engineering design
FF	failure finding task
FFT	fast Fourier transform
FMEA	failure mode and effects analysis
FMECA	failure mode, effects, and criticality analysis
FOD	foreign object damage
FTA	fault tree analysis
GADS	generating availability data system
GPM	general path model
HAZOP	hazard and operability (hazard and operability study)
HSE	health, safety, and environment
ID	internal diameter
IGV	inlet guide vane
IOW	integrity operating window
IPF	installation, potential failure, failure
IPL	independent protection layer
ITPM	inspection test and preventive maintenance
KPI	key performance indicator
LOPA	layer of protection analysis
MAWP	maximum allowable working pressure
MCM	Markov chain model
MCS	Monte Carlo simulation
MMS	maintenance management system
MOC	management of change
MTBF	mean time between failures
MTTR	mean time to repair
NCR	nonconformance report
NDT	nondestructive testing
NERC	North American Electric Reliability Council
NPSHR	net positive suction head required
OC	operating company supplied
ODR	operator driven reliability
OEM	original equipment manufacturer
OG&P	oil, gas, and petrochemical

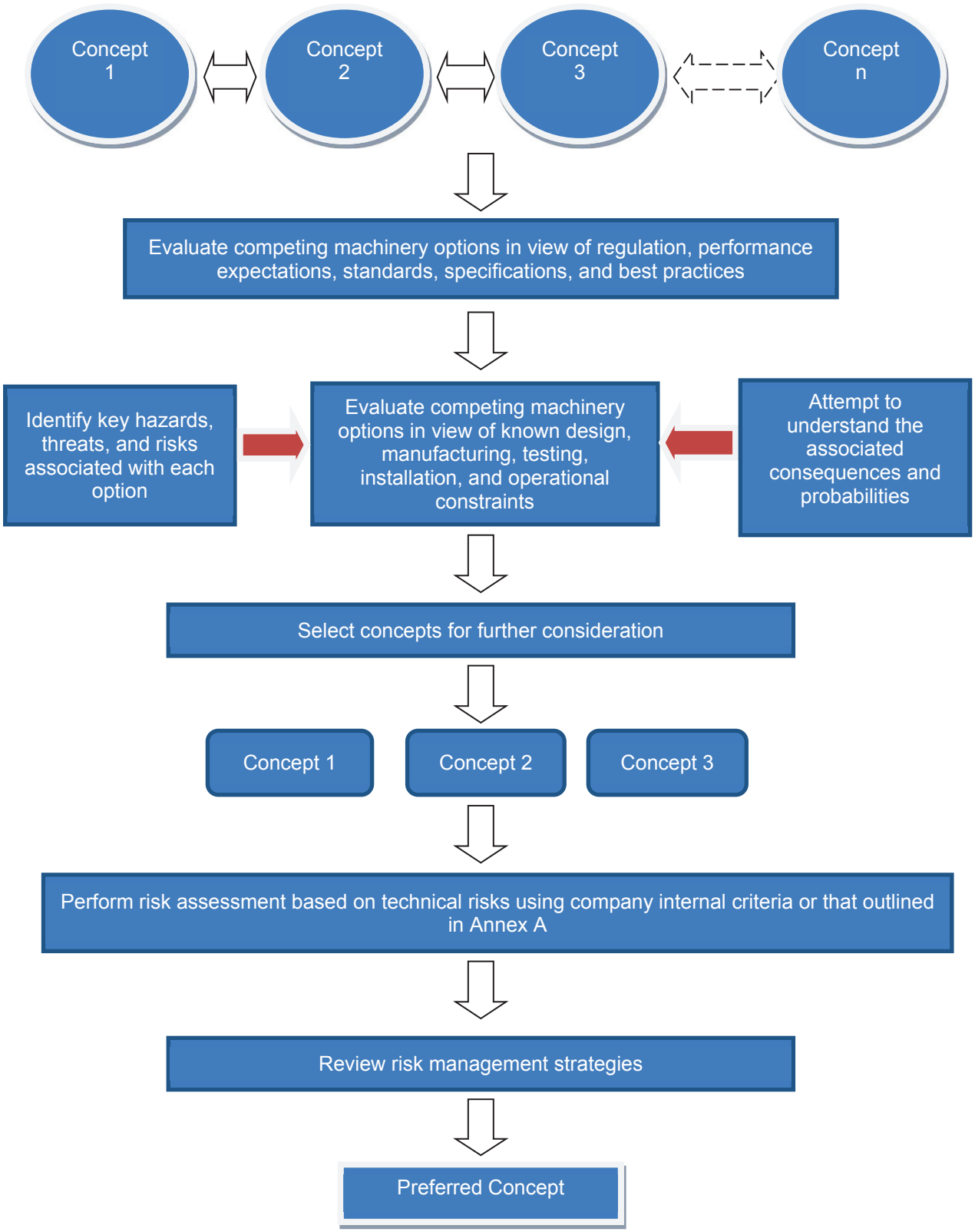
ORAP	operational reliability analysis program
OREDA	offshore reliability data
O/S	operation surveillance
PCA	principal component analysis
PDM	predictive maintenance
P-F	potential failure
PFD	process flow diagram
PFMEA	process failure mode and effects analysis
PHA	process hazard analysis
PHM	proportional hazard model
P&ID	process and instrument diagram
PM	preventive maintenance
POF	probability of failure
PRD	pressure-relief device
PSA	process safety analysis
PSI	process safety information
PSM	process safety management
PSSR	pre-start-up safety review
PT	penetration test
PV	pressure vessel
QA	quality assurance
QC	quality control
RAGAGEP	recognized and generally accepted good engineering practice
RAM	reliability, availability, and maintainability
RBD	reliability block diagram
RCA	root cause analysis
RCFA	root cause failure analysis
RCM	reliability centered maintenance
R&D	research and development
RM	reliability and maintainability
RPN	risk priority number
RUL	remaining useful life
SAFE	Security Achieved Through Functional and Environmental (Design)
SCC	stress corrosion cracking
SIL	safety integrity level
SME	subject matter expert
SOL	safe operating limit
SOP	standard operating procedure
SV	surveillance task
TA	turnaround

TDM	transient data manager
TPM	total productive maintenance
TRC	technical risk categorization
TRL	technology readiness level
UT	ultrasonic testing
V	vendor supplied
VFD	variable frequency drive
WFMT	wet fluorescent magnetic particle

4 Feasibility and Concept Selection

4.1 Introduction

Operating companies are tasked with developing pre-FEED scopes of work for major capital projects. In the majority of cases, these will duplicate similar facilities where the risk associated with processes and equipment may be adequately covered by company standards, procedures, etc. In certain cases, however, the engineering and manufacturing of previously proven machinery has been or is being relocated to unproven manufacturing locations. While a machinery vendor is responsible for meeting the product function and quality requirements, an operating company's early identification of probable machinery types, technologies, and manufacturing locations during the feasibility and concept selection stage may eliminate costly errors later on that can lead to HSE issues related to loss of containment and/or a loss of functionality that could lead to a potential process safety event. The API 691 feasibility and concept selection process is shown in Figure 2.



NOTE The feasibility and concept selection stage is applicable to both operating companies engaged in capital project studies and machinery manufacturing companies involved in R&D programs. This section is useful in establishing common methods for assessing risk in a manner that is consistent with API 17N [10].

Figure 2—Feasibility and Concept Selection Process

4.2 Technical Risk Categorization

4.2.1 Risk-based machinery management begins with assessing the technical risk category for the machinery technologies being considered during feasibility and concept selection stage of a project or product development cycle (refer to Annex A). While only limited technical information is available at this time, the high-level information can be used to provide knowledgeable practitioners of machinery engineering the opportunity to identify more challenging assets (i.e. those that are more likely to pose a HSE risk later on during FEED). In the feasibility and concept selection stage, there are various methods of assessing risks of machinery technology. Operating companies and machinery manufacturing companies also have internal criteria for risk assessment. Table A.2 is one of the methods to be used to evaluate and classify machinery risks.

4.2.2 Operating companies should identify the technical risk category of the machinery expected to operate in services outlined in 1.1.2 during the feasibility and concept selection stage of capital projects using internal criteria or that outlined in Annex A. The API datasheets in Annex H.1 may be used to define the risk category of the machinery in question.

4.2.3 The identified technical risk category should be provided to the DRP prior to the start of a FEED study.

4.3 Technology Readiness Level

4.3.1 When prototype machinery is being developed, or when proven machinery is applied to more severe operating service conditions, product qualification is necessary in order to manage the technical risks. One assessment method that can be used to underpin the qualification process is the TRL, which indicates the extent to which an item is “ready for use” given specified qualification factors/requirements. TRL indicates how far the processes in a technology qualification program for a particular technology have progressed. It should only be used with reference to a specific set of operating regime parameters and environmental conditions. If the operating regime or the planned environment changes, then the TRL may be downgraded for more demanding conditions or upgraded for less demanding conditions.

Eight TRLs have been defined, consistent with API 17N [10], ranging from a minimum of 0, corresponding to an unproven idea, to a maximum of 7, corresponding to proven technology (installed and operating in the relevant conditions). These are shown in Table 1. The gap between the initial TRL and the required TRL will generally determine the qualification effort required within a project/product development program. The initial TRL is the qualification status of the equipment when it is first introduced to a project, whereas the required TRL is the qualification status required for entrance into operations. Both initial and required TRLs should be determined for a given project. In order for an item to be assigned with a particular TRL, all the required functional and performance activities and tests, as described in the TRL definition, are to be evaluated. The operating company and machinery company should agree on the required TRL level during the feasibility and concept selection phase of a capital project when considering a new technology and product for field installation and testing. If the current technology TRL level is less than the required TRL level, a qualification program should be in place to achieve the required TRL level within the cycle time requirement of the capital project. The qualification process described in 4.4.1 to 4.4.11 should be used to bring the product technology from initial TRL to the required TRL.

4.3.2 The vendor shall identify in research proposals, inquiries, and/or requested feasibility studies any component and/or subcomponent having a TRL < 7 whose failure may lead to a loss of containment and/or a loss of functionality (see Note 2) that could lead to a potential process safety event.

NOTE 1 It can be difficult to obtain the TRL for certain components that are provided by subvendors. However, it is important for the vendor having overall package responsibility to have an understanding of the readiness level of all components within their scope, particularly those that may result in loss of containment and/or a loss of functionality that could lead to a potential process safety event.

NOTE 2 Functional failure of components that do not directly result in process safety incident can still cause a high consequence event if the overall system safety is dependent on the component working. For example, bearing failure on an unspared fire water pump could represent a loss of functionality that could lead to a process safety event, whereas a bearing failure on a potable water supply pump would not.

NOTE 3 The API datasheets (Annex H.1) can be used to summarize the TRL of these prototype components and subcomponents.

Table 1—Definition of Technology Readiness Levels

	TRL	Development Stage Completed	Definition of Development Stage
Concept	0	**Unproven Concept** (Basic R&D, paper concept)	Basic scientific/engineering principles observed and reported; paper concept; no analysis or testing completed; no design history
Proof of Concept	1	**Proven Concept** (Proof of concept as a paper study or R&D experiments)	a) Technology concept and/or application formulated b) Concept and functionality proven by analysis or reference to features common with/to existing technology c) No design history; essentially a paper study not involving physical models but may include R&D experimentation
	2	**Validated Concept** Experimental proof of concept using physical model tests	Concept design or novel features of design is validated by a physical model, a system mock-up or dummy and functionality tested in a laboratory environment; no design history; no environmental tests; materials testing and reliability testing is performed on key parts or components in a testing laboratory prior to prototype construction
Prototype	3	**Prototype Tested** (System function, performance and reliability tested)	a) Item prototype is built and put through (generic) functional and performance tests; reliability tests are performed, including: reliability growth tests, accelerated life tests, and robust design development test program in relevant laboratory testing environments; tests are carried out without integration into a broader system b) The extent to which application requirements are met are assessed and potential benefits and risks are demonstrated
	4	**Environment Tested** (Preproduction system environment tested)	Meets all requirements of TRL 3; designed and built as production unit (or full-scale prototype) and put through its qualification programming simulated environment (e.g. hyperbaric chamber to simulate pressure) or actual intended environment (e.g. subsea environment) but not installed or operating; reliability testing limited to demonstrating that prototype function and performance criteria can be met in the intended operating condition and external environment
	5	**System Tested** (Production system interface tested)	Meets all the requirements of TRL 4; designed and built as production unit (or full-scale prototype) and integrated into intended operating system with full interface and functional test but outside the intended field environment
Field Qualified	6	**System Installed** (Production system installed and tested)	Meets all the requirements of TRL 5; production unit (or full-scale prototype) built and integrated into the intended operating system; full interface and function test program performed in the intended (or closely simulated) environment and operated for less than 3 years; at TRL 6 new technology equipment might require additional support for the first 12 to 18 months
	7	**Field Proven** (Production system field proven)	Production unit integrated into intended operating system, installed and operating for more than 3 years with acceptable reliability, demonstrating low risk of early life failures in the field

4.4 Product Qualification

4.4.1 The purpose of a product qualification program is for both operating companies and machinery vendors to successfully execute risk-based machinery management during the feasibility and concept selection phase. The key deliverables from a product qualification program for API 691 machinery should include the following:

a) qualification basis including qualification targets and acceptance criteria,

b) product and technology risk assessment,

c) validation method selection and basis,

d) validation plan,

e) design review approval,

f) product performance assessment and,

g) application guide.

4.4.2 The objective of the product qualification process is to:

a) provide a structured methodology for managing risk of failure in capital projects and machinery technology R&D projects,

b) demonstrate the extent to which new technology is ready for field piloting or use in a project,

c) demonstrate the extent to which existing technology is ready for use in new applications or under extended operating conditions,

d) increase confidence in the achievement of functional and performance requirements when new technology is applied in projects.

4.4.3 The level of effort in the qualification of new machinery technology is commensurate with the level of uncertainty associated with the operating regime, the environment, and technology performance. Key considerations include the following:

a) a greater uncertainty in the operating environment of the performance of the new machinery technology will require a higher margin against failure, more robust qualification methods, and a greater weight of evidence of performance achievement,

b) the greater the COF (i.e. consequence caused by loss of containment and/or a loss of functionality that could lead to a potential process safety event), the greater the required confidence of reliable performance for the application and the greater the level of effort required in qualification,

c) the level of effort required to reduce the risk depends on the extent to which a given technology is “ready” for use in a particular application and the preparedness of the operator to implement appropriate qualification procedures for such applications,

d) the level of effort required to reduce the risk depends also on the extent of the vendor’s and industries’ experience and knowledge of the technology.

4.4.4 A product qualification program is an iterative process whereby risk is diminished over time, typically progressing through concept development, preliminary engineering, and detailed engineering stages. Stage gate validation checks are conducted upon completion of each stage, wherein the product qualification team assesses the residual technical risks, evaluates the program progress against the product requirements, and makes “go” versus “no-go” decisions. These individuals may be internal to the manufacturing company or may also include external engineering experts or end users. Product qualification is achieved when the uncertainty of all performance metrics has been reduced to acceptable levels

NOTE During a new product qualification program, vendors do not commonly share internal design processes, methodology, and design criteria. However, operating companies can request to review validation plans, product performance assessments, and functional performance test results.

4.4.5 The following activities are typically performed and documented prior to the conceptual development stage gate review meeting.

a) Establishment of qualification targets and criteria at machinery system level including:

    1) the way the product will be used,

2) the environment in which the product is intended to be used,

3) required functional specification,

4) the design target and acceptance criteria.

b) Perform feasibility study and initial risk assessment of the product and technology including the machinery system level failure modes and associated risks. Risk assessment may be conducted using company internal criteria or various methodologies outlined in Annex A.

4.4.6 The following activities are typically performed and documented prior to the preliminary engineering stage gate review meeting.

a) Refined product qualification targets and criteria. This may be accomplished by dividing machinery product into appropriate subsystems and components as well as driving the main function down to subfunctions.

b) Updated risk assessment of the product and technology. Suggested aspects to be assessed include the following.

1) The failure modes and associated risks by components and subsystems. Interfaces and interactions between the components should be included when evaluating the failure modes.

2) Any physical and/or temporal constraints that will be critical to the success of the product qualification.

3) Validation methods and development plans containing engineering activities to address the identified failure modes and risks.

4.4.7 The following activities are typically performed and documented prior to the detailed engineering stage gate review meeting.

a) Successful execution of analytical validation (see 4.4.10), including engineering analysis, assumptions, and the performance margins for the failure modes,

b) Functional performance testing (see 4.4.11), including but not limited to material sample testing, component testing, prototype testing, pilot unit testing, and system testing. The purpose of the testing may include validating the product function, performance, and durability.

c) Assessment of whether the results achieved meet qualification targets. In the final stage of the qualification program, the qualification is achieved once the product meets all its requirements and both the risk and the uncertainty have been reduced to acceptable levels. Final product specification and application guidelines should be documented based on the results of the assessments.

NOTE If some functional or performance requirements of the new product are not met, several actions can be taken:

1) redesign the product and identify further qualification activities to meet qualification targets;

2) limit the operating envelope for the new product and increase inspection and maintenance requirements to collect evidence.

4.4.8 Providing there is full disclosure of the qualification status, the machinery vendor may elect to offer prototype technology to the operating company before completion of the product qualification process. In addition to the aforementioned stage gates, the machinery vendor should pass an approval stage gate before entering the market for field application to determine that:

a) the residual technical risks of new technology can be mitigated within a reasonable time frame for field piloting or use in a project,

b) the residual technical risks of existing technology can be mitigated within a reasonable time frame in new applications or under extended operating conditions.

4.4.9 The approval stage gate for a new technology or product should clearly state the operating envelope for which it has been analytically validated and/or functionally tested.

4.4.10 A key element of the product qualification process is analytical validation, which provides the vendor a quantitative basis for design.

4.4.10.1 Component and subcomponent designs identified in 4.3.2 shall be subjected to analytical validation in accordance with Figure 3. Suggested validation methods include the following.

a) Analytical methods based on existing procedures, handbook solutions, and mathematical formulas,

b) Numerical methods such as finite element analysis (FEA), computational fluid dynamic (CFD) analysis, dynamic modeling, etc.

c) Empirical correlation and statistical analysis.

d) Engineering judgments based on previous experience with similar equipment and operating conditions.

4.4.10.2 Following the analytic validation for the component or subcomponent, a risk analysis should be conducted. Any designs that are assessed to have high residual risk, as defined in Figure 3, should undergo functional performance testing.

NOTE 1 Machinery manufacturing companies can use company internal criteria or various methodologies outlined in Annex A for risk assessment of the design.

NOTE 2 ISO 12100 [3] can also be used to provide guidance to vendors in how risk assessments and reduction may be conducted and documented.

- **4.4.10.3** If specified, machinery that is identified as having high residual risk by the vendor or the operating company during the feasibility and concept selection stage shall be validated within its expected operating envelope. The extent of design validation shall be agreed upon between the vendor and operating company.

NOTE Annex B.2 lists commonly considered machinery attributes to be validated as part of product qualification.

4.4.11 Functional testing is the most common approach to reduce uncertainty during the product development cycle and product qualification program.

4.4.11.1 The functional test logic is illustrated in Figure 4. The design of the test program should be based on a detailed understanding of the failure mechanisms expected for the operating conditions to which the product will be exposed.

NOTE It has to be considered that many machines for process applications are tailored for the specific service conditions. Prototype testing or environment testing is typically only done for critical parts at a component level. System testing an entire package is usually only conducted in alpha/beta versions for machinery with high system level risk incorporating significant developmental advances.

4.4.11.2 Following the functional testing for the component or subcomponent, a risk analysis should be conducted. Any designs that are assessed to have high residual risk, as defined in Figure 3, should be rejected. A modified or alternative design concept should be considered for qualification.

- **4.4.11.3** If specified, an operator may elect to pilot test emerging technology in a field application before roll-out across multiple facilities. The field testing scope, acceptance criteria, and documentation requirements shall be mutually agreed upon between the operator and the vendor.

• 4.5 API 691 Feasibility and Concept Selection Facility Audit

If specified, an API 691 facility and concept design audit shall be conducted using company internal criteria or the methodologies outlined in Annex G.

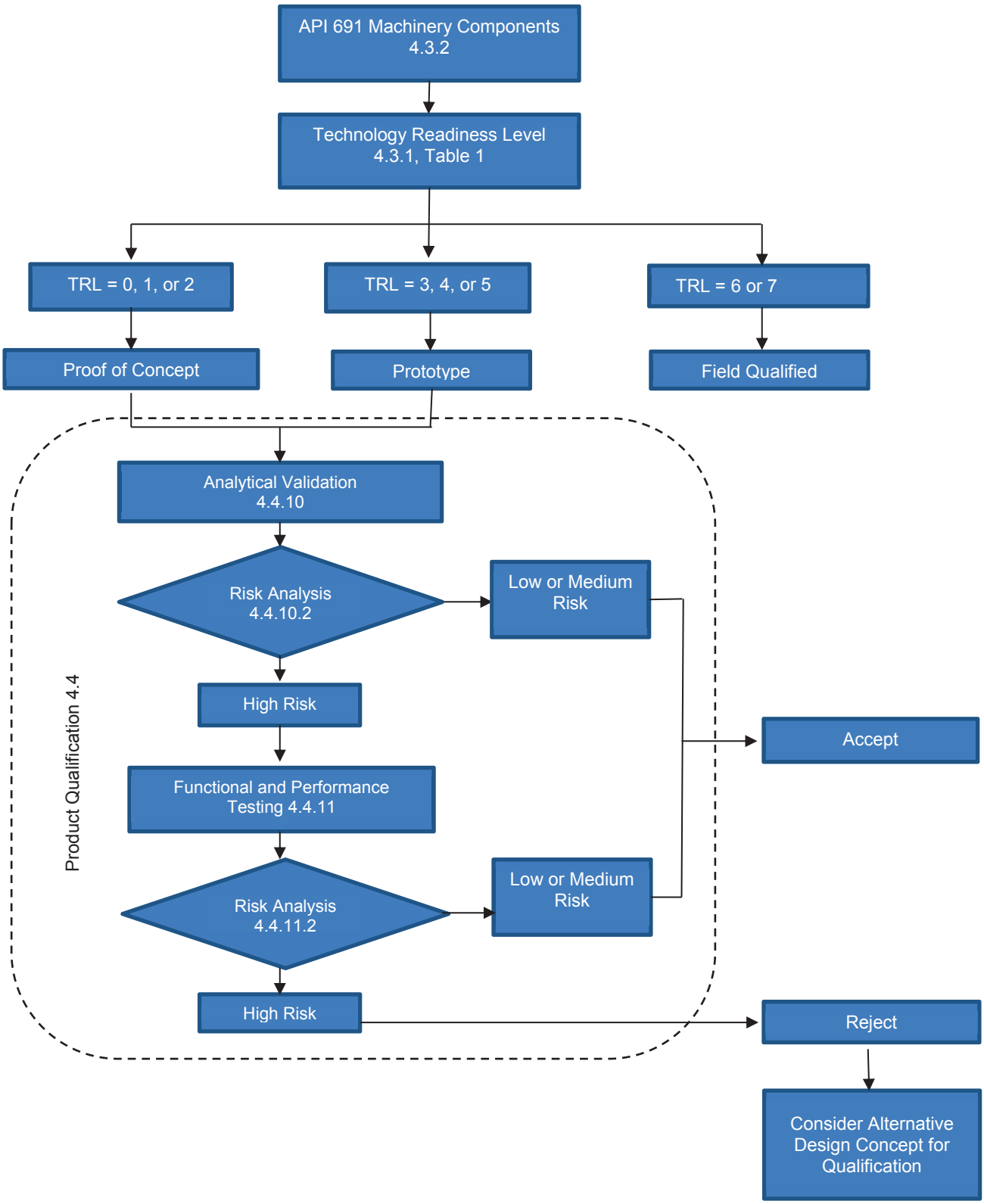


Figure 3—Technology Readiness Process Flowchart

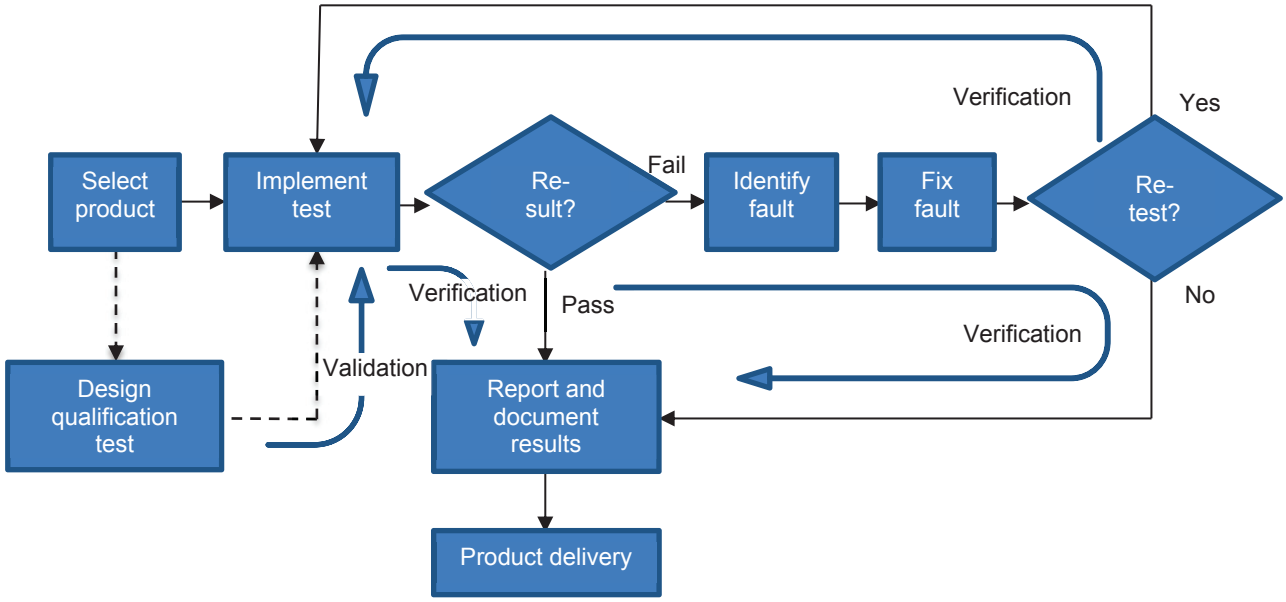


Figure 4—Functional Performance Test Logic Flowchart

5 Front-end Engineering Design

5.1 Introduction

FEED involves the identification of machinery technologies that are deemed capable of meeting operational and performance targets addressing:

a) health,

b) safety,

c) environmental compliance,

d) process availability,

e) production capacity,

f) turnaround (TA) cycle frequency equipment and facility design life.

While base API standards are considered the foundation upon which machinery selection is made, the majority of operating companies apply additional engineering specifications, practices, and overlays that enable appropriate technologies to be successfully applied to machinery for specific processes and applications.

The purpose of this section is to define requirements for risk-based machinery management during FEED to address HSE risks associated with loss of containment and/or a loss of functionality that could lead to a potential process safety event.

Preliminary machinery risk assessment process during FEED is shown in Figure 5.

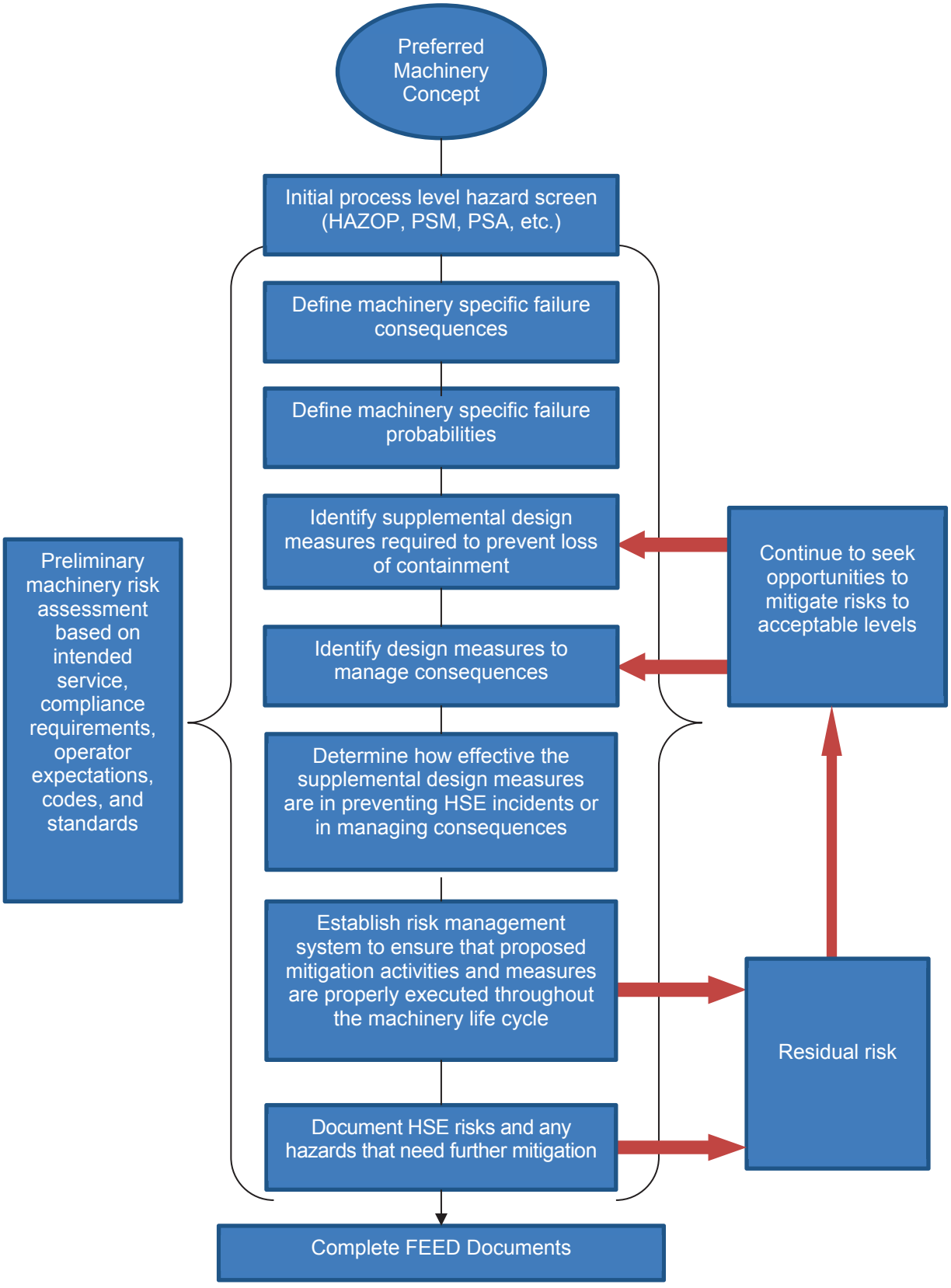


Figure 5—Preliminary Machinery Risk Assessment Process

5.2 Preliminary Machinery Risk Assessment

5.2.1 Purpose

The purpose of the preliminary machinery risk assessment is to identify all “large-scale” potential hazards in order to later assess the associated risks and provide targeted mitigations to be included within the final FEED documents.

5.2.2 Process safety and environmental hazards are first addressed during HAZOP, PSM, or process safety analysis (PSA) studies that are part of early design activities. Initial screening at the process level may be conducted to identify machinery warranting more rigorous evaluation.

5.2.3 Unless otherwise specified, the operating company or DRP shall perform a PFMEA on all API 691 Machinery to:

a) confirm that the risk level is within company defined limits,

b) identify most appropriate risk mitigation options.

NOTE 1 Risk assessments can be conducted using a variety of approaches outlined in Annex A.

NOTE 2 IEC 60812 is a useful guide when performing PFMEAs.

NOTE 3 The API 691 datasheets (Annex H) can be used to specify the preferred methodology.

NOTE 4 Annex I (API 691 FMEA worksheet) can be used to perform an API 691 PFMEA.

NOTE 5 DFMEA can be useful in completing an API 691 PFMEA (refer to 6.3 below).

5.2.3.1 The deliverables from the preliminary machinery risk assessment include:

a) a completed risk assessment defining unmitigated risk in terms of both POF and COF with sufficient detail to define the mitigation options,

b) defined machinery boundaries,

c) a list of relevant high-level failure modes (at the asset or equipment level) that were considered (refer to Annex C),

d) defined risk mitigations potentially affecting process design, or equipment selection (refer to 1.2.3),

e) risk ranking list identifying the highest to lowest risks of concern.

NOTE 1 The API 691 datasheets (Annex H) can be used to specify the appropriate risk assessment steps, methods, and deliverables for FEED.

NOTE 2 Corporate process safety and risk management groups will typically have methodologies and practices covering aspects of these assessments. It is the intent of this recommended practice that these methodologies can be utilized to the extent possible.

NOTE 3 Assessments can be conducted using a variety of approaches outlined in Annex A.

5.2.4 Supplementary Protective Measures

As applicable, operating companies and/or their DRP shall identify supplementary protective measures that are required to attain acceptable risk from loss of containment and/or a loss of functionality that could lead to a potential process safety event for design conditions and credible off design conditions such as:

a) improved sealing,

b) backup protective control devices,

c) relief valves and venting (e.g. blowdown),

d) greater factors of safety in design,

e) enhanced CM (see Annex E),

f) additional inspections,

g) secondary containment,

h) remotely operated isolation valves,

i) machinery vibration, bearing temperature, and axial position monitoring system,

j) bearing bracket upgrades,

k) machinery upgrades (e.g. obsolete equipment),

l) improved lubrication systems,

m) deluge and firefighting systems,

n) gas release alarms,

o) pressure boundary material upgrade,

p) machinery prognostics (see Annex F),

q) emergency stop functionality,

r) evacuation procedures.

5.2.5 The identified supplementary protective measures shall be included in the company issued preliminary design specifications and or equipment (e.g. API 610) datasheets. Alternatively, API 691 datasheets in Annex H may be used.

5.3 Reliability, Availability, and Maintainability Analysis

5.3.1 The principal objectives of RAM analysis include the following.

a) Evaluate the ability of the system to operate at acceptable production levels.

b) Support the definition of the maintenance or intervention support strategy.

c) Represent the combined reliability analysis and modeling effort in operational terms.

d) Determine the mean availability to evaluate the present design or to compare it against two or more competing options. The economic model is derived from plant inputs or estimates of the capital, procurement, installation, disposal, operating, and maintenance costs.

e) Identify and rank the contributors to production losses and potential unplanned flaring that may result in significant HSE events.

f) Assess maintenance policy such as number of repair teams, rig mobilization policy, spare parts management, and repair priority in case of simultaneous failures.

- **5.3.2** If specified, RAM-1 analysis shall be conducted during FEED in order to establish:

a) probability of unplanned flaring events,

b) buffer sizing and location,

c) process unit redundancy and sizing,

d) process technology,

e) major utility needs,

f) equipment redundancy,

g) first pass spares analysis for major equipment.

NOTE Additional guidance on performing RAM analysis can be found in Annex A (A.2.4.9).

5.4 Machinery Design and Selection

5.4.1 During FEED, blanket assumptions are often made regarding pressure losses across process exchangers, vessels, control valves, etc., which can vary significantly from individual losses as defined in the vendor's specifications. Certain license processes will also recommend that a +10 % margin on flow be added to accommodate uncertainty during operation. Operating companies are encouraged to closely audit assumed standard pressure losses and design margins used by engineering and procurement contractors to ensure they are consistent with company specifications, industry standards and recommended practices, and license process requirements. Excessive process engineering and mechanical design margins may result in off design operation that can impact reliability [11] and increase the risk of safety, health, and environmental events.

5.4.2 Selection of machinery during FEED shall follow a detailed review of all process assumptions along with various process operating scenarios. The operating company or DRP should ensure that adequate operational flexibility exists in the selected machine frame size to accommodate potential process changes during detailed design.

5.4.3 Process optimization changes affecting equipment selection should be thoughtfully reviewed by machinery engineers to ensure that final selections meet necessary operating ranges including turndown and ensure safe and reliable start-up and shutdown sequences.

5.4.4 For API 691 Machinery, the vendor shall identify all components and subcomponents having a TRL < 7 whose failure may lead to a loss of containment and/or a loss of functionality that could lead to a potential process safety event. The API datasheets in Annex H.1 may be used to summarize the TRL of these prototype components and subcomponents.

5.4.5 The operating company or DRP should conduct a design and reliability evaluations validating proposed machinery designs [12]. Validation checklists found in B.2 and B.4 may be helpful in making appropriate technical selections.

5.5 Process and Instrument Diagram (P&ID) Reviews

Safe operation of machinery covered by this recommended practice depends on comprehensive review of piping and instrument diagrams.

NOTE Annex B.3 can be used to ensure that appropriate and thorough design checks are made during FEED.

5.6 Long Lead Machinery

In order to meet overall project requirements, it is recognized that some API 691 Machinery may need to be procured during FEED due to long lead times from original equipment manufacturers (OEMs). In these cases, the requirements specified in Section 6 (Detailed Design) shall be performed during FEED.

5.7 Vendor Qualification

5.7.1 It is the intent of this recommended practice to provide guidelines to address quality assurance (QA) and quality control (QC) features necessary to ensure the integrity of API 691 Machinery. For the purpose of

this recommended practice, ISO TS 29001 [13] is recommended for establishing an effective implementation of processes, procedures, and information to ensure adequate vendor programs for risk-based integrity management of machinery.

5.7.2 API 691 Machinery shall be supplied by vendors having a quality management system that is in accordance with ISO TS 29001, ISO 9000 [14], or equivalent. The quality management system shall be third-party certified.

5.7.3 Risk-based machinery management is dependent upon the machinery vendor's supply chain, internal engineering and manufacturing processes, and agreements with operating company organizations to gather and share data between responsible parties. The design and development of these processes shall ensure free flow of information. Information shall be available in electronic formats to enable uniform transmittal, use, and storage of shared data.

5.7.4 The vendor shall provide evidence to demonstrate effective management of documentation and data relative to identified API 691 Machinery. The ability to share relevant information is considered essential. Demonstration of effective management of data should include:

a) the ability to demonstrate reasons specific subvendors were selected for particular components and or services,

b) the ability to demonstrate measurement and monitoring of subvendors of products and services,

c) the ability to demonstrate processes utilized for verification and validation of product characteristics,

d) the ability to demonstrate subvendor communication/data sharing processes relative to subcomponents of the final machinery delivered to customers,

e) the ability to demonstrate communication/data sharing processes with customers/users of machinery,

f) the ability to demonstrate processes to identify customer complaints and specific actions taken to resolve noted issues,

g) the ability to demonstrate processes to identify warranty claims and specific actions taken to resolve noted issues,

h) corrective and preventive action to mitigate machinery failures,

i) the ability to provide spare parts support,

j) the ability to provide on-site/offsite service and repair support.

- **5.7.5** If specified, an API 691 FEED audit shall be conducted using company internal criteria or the methodologies outlined in Annex G.

5.8 Operations, Maintenance, and Facilities Strategies

5.8.1 Operating companies or their designated representatives shall develop operations and maintenance strategies that address the following key items:

a) spare parts requirements,

b) predictive maintenance (PDM) and PM services,

c) site-wide lubrication strategies,

d) safe operating limits (SOLs),

e) IOWs,

f) emergency response,

g) training.

5.8.2 Operating companies or their designated representatives should consider the FEED planning and executing activities listed in Table 1, API 1FSC. [15]

5.9 Optional Field Testing

5.9.1 General

Optional field testing can be performed either during the installation and commissioning phase (5.9.2 to 5.9.5) or during the operations and maintenance phase (5.9.6) for the purpose of reducing the risk of unexpected delays or failure that may lead to HSE impacts.

NOTE Typical testing performed during commissioning generally does not prove the full functionality of the assembled machinery nor allow for accurate performance assessments based on the actual operating conditions.

5.9.2 Steam Turbine Solo Run Test

- If specified, steam turbine solo run testing shall be performed during commissioning in the field.

5.9.3 Motor Solo Run Test

- If specified, motor solo run testing shall be performed in the field.

5.9.4 Centrifugal, Axial, and Screw Compressor Inert Gas Test

- **5.9.4.1** If specified, compressor inert gas testing shall be performed during commissioning.

NOTE Inert gas testing runs offer the following benefits to successful initial start-up:

a) verification of process (yard) valve sequencing,

b) verification of start logic,

c) partial verification of alignment in running condition,

d) verification of machinery bearing and vibration equipment functionality,

e) verification of machine integrity with an inert gas—any leakage will be nonflammable,

f) additional process piping clean-up and ability to clean strainers without time-consuming gas-free operations.

5.9.4.2 Plans for inert gas testing should be thoughtfully coordinated between the operating company, DRP, and the vendor. The process coolers supporting most compressors are not designed to remove the heat of compression associated with nitrogen; therefore, to prevent potentially damaging discharge temperatures, inert gas test runs with nitrogen are usually of a short duration or at a reduced speed. As an alternative and if available, inert gas testing with helium provides for longer test runs. In all cases, the vendor should confirm that the compressor design is capable of running on the inert gas and all auxiliaries and instrumentation are appropriately selected to achieve the desired accuracy. Significant differences in gas molecular weight can effect differential pressure style flow measurements.

5.9.4.3 Performance curves for inert gas testing should be provided by the vendor.

5.9.4.4 The inert gas test plan should include considerations for the anti-surge valve(s) and spillback piping. Procedures should ensure sufficient cooling of the gas and protection from over temperature. Considerations can include replacing the anti-surge valve(s) with spools or removal of valve trim, to allow unobstructed flow through the anti-surge loop. After test run, the anti-surge valve internals should be inspected to ensure it has not been plugged or damaged from debris.

5.9.5 Reciprocating Compressor Inert Gas Test

- If specified, reciprocating compressor inert gas testing shall be performed.

5.9.6 Field Performance Test on Process Gas

- **5.9.6.1** If specified, API 691 Machinery shall be field performance tested on process gas during the operating and maintenance phase. The operating company or DRP shall specify the required scope, and design (e.g. instrumentation to accurately measure pressure, temperature, flow rate, and gas composition).

NOTE Field performance testing using process gas can typically only occur once the plant has been fully commissioned and all process units have been started up. Generally this happens after mechanical completion certificates have been signed and the operations and maintenance phase has commenced (refer to 8.3.6).

- **5.9.6.2** If specified, both the DRP and vendor shall be present during this post-commissioning testing.

NOTE Appropriate ASME Power Test Codes can be used to specify the necessary field test instrumentation to achieve the required accuracy for performance assessments.

6 Detailed Design

6.1 Introduction

Once the efforts of FEED are completed, detailed design commences with the validation of the process design. It is not unusual for detailed design contractors to identify improved methods, technologies, or more accurate process conditions that influence machinery designs. This may in certain cases change the risk classification of machinery previously evaluated in FEED. It may also result in machinery that had not been previously specified or evaluated. As more accurate technical information becomes available, machinery engineers are better able to assess risk and determine the correct risk mitigation activities and strategies to be applied throughout the equipment life cycle. The focus of detailed design from a risk-based machinery management perspective is to develop purchase quality design specifications that sufficiently reduce the future probability and/or consequence of HSE events while meeting other business objectives. The key requirements for the detailed design phase are outlined in Table 2.

6.2 Detailed Machinery Risk Assessment

6.2.1 General

The purpose of the detailed machinery risk assessment is to validate the preliminary risk assessment, identify any new hazards, and assess risk for all equipment within the boundary of the selected machinery package, such that specific, focused tasks or other actions can be identified to mitigate unacceptable (high) risks to an acceptable level. As mentioned in Section 5, many operating companies possess and utilize existing corporate methodologies for the analysis of risk. This recommended practice does not prescribe the use of a specific risk assessment methodology. Whenever applicable, users may utilize existing methodologies, and/or supplement them, as deemed necessary. A risk assessment methodology employed in detailed design should:

a) consider POF and COF, whether qualitative or quantitative, in determining risk,

b) assess unmitigated risks at the failure mode level for all equipment within the defined machinery boundary limits,

c) assess mitigated risks for the various tasks and other actions proposed,

d) confirm that the mitigated risk is acceptable,

e) provide sufficient documentation of the risk assessment to allow life cycle management of risk, per the requirements of Section 8.

Table 2—Outline of Detailed Design

Hazard Identification/Hazard Operability Studies (Process Level)	Having performed HAZID and HAZOP during FEED—further work along these lines is only likely to be required during the detailed design phase if there are major changes occurring in process designs, operating conditions, standard operating procedures, etc.
Detailed Machinery Risk Assessment [For API 691 Specified Machinery] (Machinery Failure Mechanism Level)	Updating the preliminary machinery risk assessment to include detailed design data allows for the completion of a detailed machinery risk assessment at the failure mechanism level for all equipment within the detailed machinery boundary (see Annex C). The operating company should provide guidance on the risk criteria and methodologies to be used whether internal or those outlined in Annex A. The recommended practice requires a vendor provided design failure modes and effects analysis (DFMEA), which can optionally be incorporated into a process failure modes and effects analysis (PFMEA) constructed by the operating company and/or their DRP
Risk Mitigation	The risk mitigation includes design upgrades identified in the detailed machinery risk assessment. While these will largely have been implemented during FEED, further improvements may be possible for specific operating services depending on the process design, operating experience, selected machinery vendor, and the content of operating company internal engineering specifications
Detailed Design Project Engineering Specifications for API 691 Machinery	Detailed design project engineering specifications for API 691 Machinery will include: — qualification of manufacturing and design — safe operating limits (SOLs) — integrity operating windows (IOWs) — supplemental protection measures — risk-based installation and commissioning plans — preventative maintenance tasks targeting failure mechanisms that might lead to a loss of containment and/or a loss of functionality that could lead to a potential process safety event
Standard Operating Procedures for API 691 Machinery	The operating company is required to develop machinery standard operating procedures that ensure to the extent possible that machinery is operated within the established SOLs and IOWs using checklists, guidelines, controls, alarms, shutdowns, and demonstrated operator competency

6.2.2 Unmitigated Risk

Companies have varying levels of risk mitigation measures already designed into their internal requirements. For the purposes of API 691, unmitigated risk is that process and machinery risk that has not already been adequately addressed for a given service by or within:

a) company overlays to API standards,

b) project engineering specifications,

c) upgraded materials selections,

d) supplemental layers of protection included in design specifications,

e) automated CM or machinery protection,

f) basic operator walk-through surveillance and response to installed alarms.

NOTE Unmitigated risk typically does not include:

a) preventative maintenance,

b) PDM.

c) specific SV or CM tasks beyond basic walk-throughs.

6.2.3 Documentation Requirements

The detailed machinery risk assessment builds upon the results of the preliminary risk assessment conducted in Section 5 and should utilize the following information:

a) finalized process conditions,

b) finalized P&IDs,

c) assessment of individual assets within the defined boundaries of the API 691 Machinery,

d) completed API datasheets (e.g. API 610),

e) special design requirements of the selected machinery vendor [e.g. comments and exceptions to the API standards, baseplate layouts, piping arrangements, input received on loss of containment and/or a loss of functionality that could lead to a potential process safety event, and critical failure mechanisms from the design failure mode and effects analysis (DFMEA) (refer to 6.3)],

f) potential HSE events identified from RAM-2 modeling, if specified (refer to 6.5),

g) SOLs,

h) IOWs,

i) manufacturing, testing, or design experience limitations of the vendor for similar or identical machinery.

Figure 6 depicts the fundamental detailed risk assessment process.

6.2.4 Allowable Methodologies

- Unless otherwise specified, the operating company or DRP shall develop a PFMEA.

NOTE 1 Risk assessments can be conducted using a variety of approaches outlined in Annex A; however, the PFMEA is the most common conducted throughout the industry.

NOTE 2 The API 691 datasheets (Annex H) can be used to specify the preferred methodology.

NOTE 3 Annex I (691 FMEA worksheet) can be used to perform an API 691 PFMEA.

NOTE 4 DFMEA can be useful in completing an API 691 PFMEA (refer to 6.3 below).

6.2.5 Declassifying API 691 Machinery

Some machinery, including equipment, components, and subcomponents within the selected boundary limits, may not require risk mitigation and are therefore not subject to further requirements of this recommended practice. Operating companies may at their discretion declassify equipment previously defined during FEED as API 691 Machinery should risk levels be reassessed to be tolerable based on:

a) changes in process conditions,

b) relocation to unmanned locations,

c) deletion of scope,

d) changes in design,

e) errors found in earlier risk assessments.

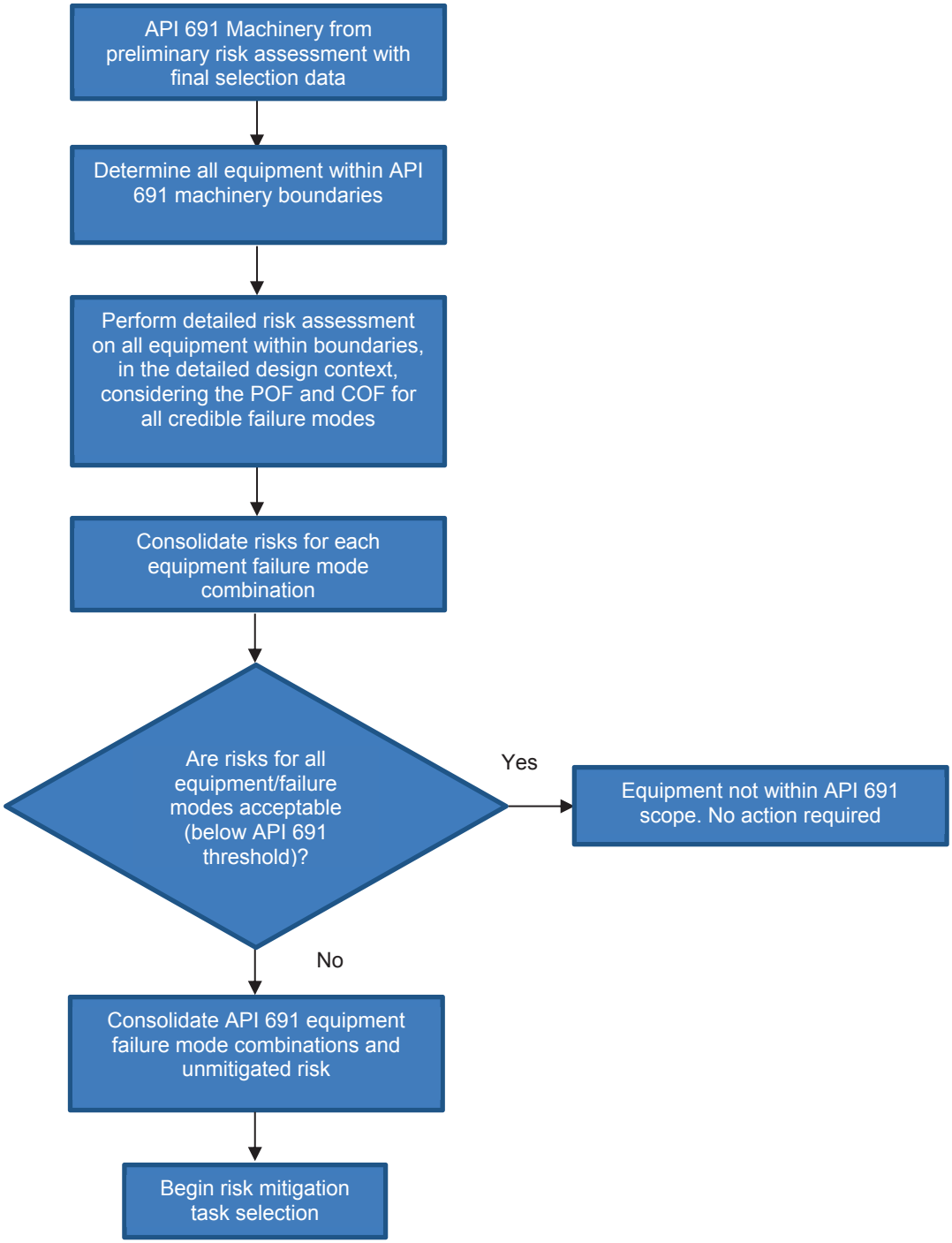


Figure 6—Fundamental Detailed Risk Assessment Process

6.3 Design Failure Mode and Effects Analysis

6.3.1 DFMEAs often contain useful information that may allow users of machinery to better understand potential failure mechanisms. The data the vendor provides with the DFMEA shall include where applicable:

a) assumptions made as to machinery operating context,

b) installation specifications,

c) limits of operation (e.g. IOWs assumed in the design and/or assumed to meet functional requirements),

d) routine maintenance activities that are assumed for the DFMEA results to remain valid,

e) preservation maintenance tasks recommended and assumed to be performed in the period from machinery delivery to commissioning and initial start-up,

f) HSE requirements associated with operations and maintenance of equipment.

NOTE For additional information on constructing a DFMEA, refer to Annex A.

6.3.2 For API 691 specified machinery, the vendor shall provide a DFMEA addressing failure modes related to a loss of containment and/or a loss of functionality that could lead to a potential process safety event.

- **6.3.3** If specified, the vendor shall provide a complete DFMEA for all failure modes and failure mechanisms that may result in HSE events. The DFMEA shall include POF and COF data based on collected, calculated, or assumed values. It is not required that a unique DFMEA be developed for each specific order, but rather that the vendor have on file a complete analysis for machinery covering the model, type, and/or design being offered.

NOTE 1 The API 691 FMEA worksheet (Annex I) can be used as a reference in developing the DFMEA.

NOTE 2 POF data can be found from sources referenced in A.2.4.9.7.

6.4 Risk Mitigation—Task Selection Process

6.4.1 Following the detailed risk assessment, tasks and strategies shall be assigned to ensure that adequate mitigation is achieved. The process outlined below and depicted in Figure 7 is focused on efficient and effective mitigation of risks associated with API 691 Machinery. The API 691 datasheets in Annex H.3 may be used to summarize the required tasks to achieve necessary risk reduction.

6.4.2 When considering tasks to prevent or mitigate the identified failure mechanisms, the following may be considered.

a) CM:

   1) SV tasks,

   2) predictive tasks,

   3) CM tasks.

b) PM:

   1) nonintrusive PM tasks,

   2) intrusive PM tasks.

c) FF tasks:

   1) functional tests,

   2) operational tests.

d) Design modifications (e.g. improved sealing and containment, or implementation of protective systems).

e) Annex C provides a list of failure modes and failure mechanisms and causes. It is recognized that users may have other failure coding systems and formats that are at an appropriate level of detail to be used to assess risk and determine mitigation strategies. Therefore, it is not the intent of this recommended practice to prescribe a failure coding format.

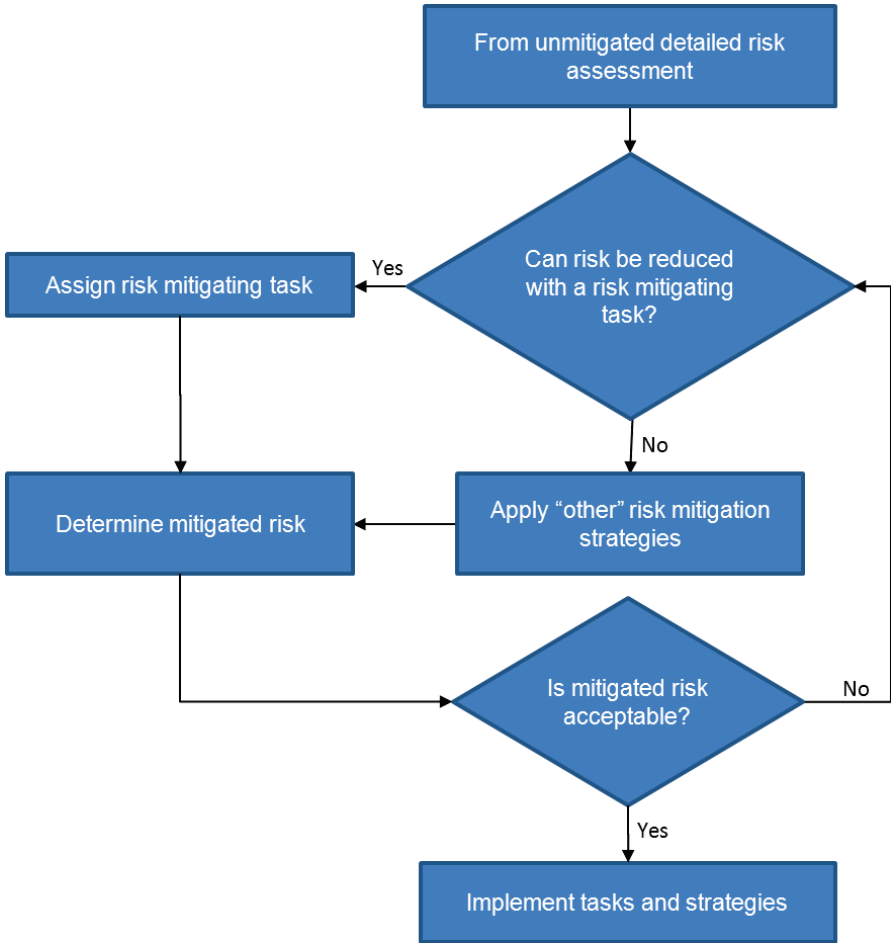


Figure 7—Fundamental Risk Mitigation Task Selection Process

f) In addition to assessment of machinery condition and prediction of future performance, CM tasks should focus on the assurance that API 691 Machinery is operated within its SOLs and IOW. Section 6.6 provides further guidance on SOLs and IOWs.

g) Annex D provides guidelines on the applicability and frequency of risk mitigation maintenance task types in addressing various failure modes and mechanisms. Annex D also provides example templates containing fundamental risk mitigation tasks by API 691 Machinery type. This is not meant to be an exhaustive list, nor should these be considered always applicable. For API 691 Machinery, enhanced CM and other potential tasks beyond those in the Annex D templates should be considered. If the task selection process is unable to effectively reduce the risk to an acceptable level, other risk mitigation strategies should be considered in order to sufficiently do so. These can include process modification, spare parts strategies, improved inspection methods, etc. These types of recommendations will often require revisiting design or other nonmaintenance aspects of the machinery application.

6.4.3 The risk mitigation task selection process defines the strategies to effectively reduce risk of operating API 691 Machinery (as designed) to an acceptable level. The primary means to do this is through proactive maintenance, operations, and/or engineering. However, virtually no strategy can completely eliminate the possibility of failure, and for some equipment failure modes and mechanisms, failures simply cannot be prevented. In these cases, the overall strategy may include contingencies for mitigation of the COFs (e.g. preexisting rapid repair and replacement strategies). This includes detailed procedures, parts identification, and skills/manpower requirements. Having API 691 Machinery repairs preplanned and proceduralized can provide significant mitigation of potential failure consequences by significantly reducing the mean time to repair (MTTR), while increasing work quality.

6.4.4 As part of the risk mitigation task selection process, requirements for machinery preservation should be evaluated. These preservation tasks should be placed into the project mechanical completion plan and executed as required. Proper execution of required preservation tasks should be documented so they can be reviewed and validated as part of the commissioning processes described in Section 7.

6.5 RAM-2 Analysis

- If specified, RAM-2 analysis shall be conducted. The primary purpose of the RAM-2 analysis, developed in detailed design, is to validate that the actual installed machinery, including all associated auxiliaries, still meets final design basis requirements. This is accomplished by building on the RAM-1 with enhanced equipment detail. In addition to the validation of as-built design, the RAM-2 analysis can also be utilized in the detailed design process as a tool to assist in decisions such as:

  a) the effect of maintenance strategy on equipment availability,

  b) finalization of other design details such as buffer sizing, utility requirements, equipment redundancy, etc.,

  c) minimizing impacts of failed equipment at the plant level.

  The final RAM-2 analysis and final model delivered from the detailed design effort should reflect the as-built design such that it can be used in the future to make informed decisions regarding operational changes and end of life criteria. As such, the RAM-2 analysis and model should be continually updated as design is finalized. Further use of the RAM model is presented in Section 8.

  Although the scope of this recommended practice only includes development and expansion of a RAM-2 (if specified) to cover primary and supporting equipment within the defined boundaries of API 691 Machinery, users may elect to develop a more comprehensive RAM model covering other details in support of achieving plant performance targets.

  NOTE Additional guidance on performing RAM analysis can be found in Annex A (A.2.4.9).

6.6 Safe Operating Limits and Integrity Operating Windows

6.6.1 For API 691 specified machinery, the vendor shall define IOW critical levels and limits. The operator shall use this information to determine SOLs, which may include the following:

a) maximum allowable vibration,

b) maximum allowable suction pressure,

c) minimum allowable suction pressure,

d) maximum allowable casing pressure,

e) maximum allowable inlet temperature,

f) maximum allowable speed,

g) minimum continuous stable flow,

h) maximum allowable solids concentration,

i) maximum allowable corrosive limits,

j) maximum allowable bearing temperature,

k) minimum lube oil pressure,

l) minimum seal gas flow.

6.6.2 The DRP shall clearly define all IOWs impacting API 691 Machinery. The vendor should review IOWs and positively verify that operation within the defined IOW levels and limits will not invalidate assumptions made within their DFMEA. The operator shall approve final SOLs. API 584 provides guidelines for determining IOWs, focused primarily on mechanical integrity and prevention of loss of containment and/or a loss of functionality that could lead to a potential process safety event. In addition, operating envelopes should be defined to sustain safe and reliable operation.

6.7 Qualification of Manufacturing and Design

6.7.1 For API 691 specified machinery, the vendor shall identify all components and subcomponents having a TRL < 7, whose failure may lead to a loss of containment and/or a loss of functionality that could lead to a potential process safety event in accordance with 4.3.2.

6.7.2 For major repairs defined by ASTM on pressure-containing components, the vendor shall obtain approval from the operating company.

6.7.3 If specified, applicable welder qualification records, weld repair procedures, and photographs shall be provided to the operating company for review and approval.

6.7.4 API 691 Machinery should be supplied by facilities qualified by experience in manufacturing the units proposed. Verification of this experience should form part of the vendor/vendor proposal. Annex B (B.4) provides guidance on the qualification of API 691 Machinery. The qualification process should demonstrate that the vendor has manufactured machinery of a similar or identical type that has successfully operated under equivalent operating conditions. The unit should be manufactured at a facility meeting the quality requirements of API Q1/ISO TS 29001, ISO 9000, or equivalent.

6.7.5 If specified, an API 691 detailed design audit shall be conducted using company internal criteria or the methodologies outlined in Annex G.

6.8 Start-up and Commissioning Plans

6.8.1 Commissioning activities should be thoughtfully planned to ensure that API 691 Machinery is prepared for installation and commissioning. Commissioning plans should ensure availability of temporary facilities to support commissioning and timely mobilization of specialty support personnel. It should define major activities and sequence of events required for precommissioning, commissioning, testing, mechanical completion, and initial start-up of API 691 Machinery and associated support systems.

6.8.2 A control and protective system narrative should be provided that describes all machinery control and protective functions including logic and should accompany a finalized cause and effect matrix. The narrative should be used by the DRP to prepare a machinery control and protection test procedure for use during commissioning.

6.9 Machinery Standard Operating Procedures

6.9.1 Improper operation, and other related human error, is a major root cause of equipment failure. This is especially true in the case of machinery, which is typically more sensitive to changes in operating conditions and excursions outside of defined IOWs. For API 691 Machinery, standard operating procedures (SOPs) shall ensure to the extent possible that machinery is operated within the established SOLs and IOWs using checklists, guidelines, controls, alarms, shutdowns, and demonstrated operator competency. SOPs shall also provide clear guidance as to actions required if/while operating outside the defined SOLs and IOWs.

6.9.2 API 691 SOPs shall address the following machinery operating modes:

a) initial start-up,

b) normal start-up,

c) normal shutdown,

d) emergency shutdown and operations,

e) any other expected nonroutine operation.

6.9.3 API 691 SOPs may be developed as standalone procedures or contained within integrated system or unit operating procedures. In any case, the requirements contained in this recommended practice shall be met.

6.9.4 API 691 SOPs should be reviewed to verify that operation will not invalidate assumptions made in the DFMEA or otherwise allow operation outside of the vendor's defined SOLs.

6.10 Facilities Completion Planning and Execution

6.10.1 Operating companies or their designated representatives should consider the detailed design planning and execution activities listed in Table 1, API 1FSC [15].

6.11 Implementation of Risk Mitigation Tasks and Strategies

6.11.1 In order to assure the desired outcomes result from the decisions made in the risk mitigation task selection process, tasks and other strategies should be fully implemented into work management systems, such that they are properly poised for execution after plant start-up. Operating company guidelines should be followed to develop proactive maintenance work orders (PMs) and job plans that address what work is to be done and what materials and labor (including skills) are required.

6.11.2 Given the variability in work management systems employed by users, this recommended practice prescribes only the minimum requirements for proper implementation of tasks and strategies. The implementation of PMs and other tasks identified as key HSE risk mitigations in 6.4 should adhere to the following:

a) work instructions for tasks should be written to a level of detail commensurate with the skill levels of the workforce who will be executing the tasks, as well as the risk associated with the equipment being maintained, monitored, or tested;

b) the proper parts and materials necessary for execution of the tasks should be clearly defined such that the risk of use of the wrong parts or materials is minimized to as low as reasonably possible (ALARP);

c) for tasks that are of a level of complexity that special skills are required, formal maintenance procedures should be developed to an appropriate level of detail to control the quality of work and assure adequate management of this risk;

d) work instructions and formal maintenance procedures should contain and clearly indicate appropriate cautions and warnings based on critical quality checkpoints and other risk criteria identified in the vendor’s DFMEAs, API 691 detailed risk assessments, and defined SOLs and IOWs;

e) work instructions and formal maintenance procedures should include clear indication of data that needs to be captured as part of work execution and closeout of the task (e.g. as-found/as-left condition, clearances, material cause of failure, parts failed/replaced, other action taken based on inspection), and this data should be organized for inclusion in the required processes described in Section 8.

6.11.3 Some API 691 risk mitigation tasks may be managed outside of a computerized maintenance management system/enterprise asset management (CMMS/EAM) system. Examples are tasks managed in systems such as operator activity systems, PDM systems, advanced CM systems, etc. Similar to the tasks implemented through the CMMS/EAM, these tasks should be detailed, packaged, and formatted appropriately, per the implementation requirements of the target work management systems and/or analysis tools.

6.11.4 API 691 risk mitigation tasks and strategies should be tracked through implementation. A detailed implementation plan should, therefore, be developed to accomplish this. This plan should also include defined actions to reevaluate required risk mitigation tasks or strategies, should any recommendations be determined to be not practical to implement as originally scoped. Changes that are proposed following initial start-up should be governed by the processes described in Section 8.

6.11.5 Implementation plans should also identify the process and enabling tools that will manage the tasks [CMMS, PDM, operator driven reliability (ODR) tools, etc.]. Included, as well, should be resource requirements and required training for personnel to be able to properly execute the tasks and strategies associated with API 691 Machinery.

7 Installation and Commissioning

7.1 Introduction

7.1.1 Following the detailed design phase, the operating company or their installation contractor will be tasked with ensuring that high-risk machinery are installed and commissioned in accordance with applicable manufacturing guidelines, API standards, company specifications, and prevailing national and local codes. Successful completion depends on thoughtful planning to ensure that the machinery, including instrumentation, controls, and auxiliaries, are fully functional at process start-up. An important step is functional testing of hardware and software during commissioning to achieve the risk reduction identified during FEED and detailed design. Work begins with a comprehensive review of the commissioning procedures and test program that were completed during detailed design. The operating company or their installation contractor shall confirm the acceptability of the following:

a) installation and commissioning or decommissioning and decontamination schedule,

b) installation and commissioning or decommissioning and decontamination procedures,

c) the sequence in which the various elements are integrated,

d) the criteria for acceptance of safety related systems through functional testing,

e) procedures to resolve nonconformances falling outside of specified requirements.

NOTE 1 This section is not intended to provide a comprehensive guide for proper machinery installation, commissioning, and start-up. It is assumed the operating company and DRP execute good installation, commissioning, and start-up practices normally associated with special-purpose machinery.

NOTE 2 TRL 6 and below machinery, components, and subcomponents can require additional support for the first 12 to 18 months in the field.

7.1.2 The operating company or their DRP should consider the recommended precommissioning and commissioning activities outlined in API 1FSC.

7.2 Installation

- **7.2.1** If specified, API 691 Machinery shall be installed in accordance with API 686 [8].

7.2.2 Any deviations or changes to the process and machinery design including auxiliaries, controls, and instrumentation should be implemented under an MOC process to assure changes are properly reviewed, communicated, and documented and resulting actions are tracked to completion.

All changes to design should be considered in the context of any PFMEA that may have been developed during the detailed design phase. Any impact on residual risk should be documented, accepted, and approved by the owner.

7.3 Commissioning, Decommissioning, and Decontamination

7.3.1 General

Risk mitigations identified by PFMEA conducted during FEED or detailed design should be assessed, to extent practical, for functionality and effectiveness during commissioning.

Verification of risk mitigations during commissioning or decommissioning and decontamination is important for components/systems where functionality and effectiveness have been assumed to reduce risk but where functionality and effectiveness of the complete and integrated system have not been proven during factory acceptance tests.

7.3.2 Commissioning, Decommissioning, and Decontamination Procedures

7.3.2.1 Procedures should be developed to specifically address API 691 Machinery including associated auxiliary and support systems; machinery control, protective, and monitoring systems; and other functioning systems or components that are part of the risk reduction strategy.

7.3.2.2 Procedures should:

a) include validation that preservation tasks have been properly performed,

b) contain appropriate caution and warning statements and controls to prevent operation outside of the IOWs or other SOLs,

c) capture and acceptance of CM results as part of overall acceptance criteria,

d) capture baseline data and confirm action levels for risk mitigation tasks,

e) include validation of proper set points in machinery control, protective, or monitoring systems,

f) include activities to confirm the proper function of all support equipment.

7.3.2.3 Procedures should be reviewed by the vendor. Vendors should verify that execution of the procedures will not invalidate assumptions made within DFMEA or otherwise allow operation outside of the assumed SOLs.

7.3.3 Field Functional Safety Testing

7.3.3.1 Risk mitigations that rely upon instrumentation and controls to provide protective functions should be functionally tested during the commissioning phase prior to the initial start-up.

7.3.3.2 Functional testing preparation for instrument and controls should include the following.

a) Verify that the final approved version of machinery control and protective software has been installed. Any logic changes made since factory testing should be reviewed with vendor.

b) Confirm any temporary modifications made to the machinery control and protective software or the unit control panel during factory acceptance testing have been removed.

NOTE The items mentioned are not exhaustive and the operating manuals may provide other items to consider in preparation for functional test of instrumentation and controls.

7.3.3.3 Changes to the logic, set points, cause-and-effects matrix, or control variables for machinery protective functions made during installation and commissioning should be reviewed by the vendor and approved within an MOC system. A log of these changes should be included in the turnover documentation along with any necessary changes to PFMEA assumptions made during detailed design.

Instrument and control function testing should be performed with the final configuration of field device, cabling, intermediate signal conditioning hardware, terminations, and logic.

7.3.3.4 The test procedure should provide a structured, sequential testing methodology based on the cause and effects matrix for all protective functions. Interlocks and permissives should be tested in both the “OK” and the “prohibited” conditions in such a way that both the instrument loop and the logic are tested.

7.3.4 Process Safety Valves

Pressure-relief devices (PRDs) mitigating high-risk failure modes should be tested prior to initial start-up per API 576. Documentation and testing of process safety valves should be accomplished per API 576 or operating company’s procedures.

NOTE 1 PRDs are typically covered by site mechanical integrity procedures that are often broader in coverage and have additional requirements (e.g. for test facility qualification, documentation).

NOTE 2 Other API standards often apply if other equipment is protected by the same PRDs (e.g. API 510, API 570).

7.3.5 Auxiliary Equipment

Risk mitigations that rely upon capacity, functionality or redundancy of auxiliary equipment should receive final testing in the as-built condition during commissioning prior to initial start-up. This testing would typically include auto-start of standby pumps, stroke checks of control valves including responsiveness to command signals, and overspeed trip checks. In design of the test, special consideration should be given to transient and off design conditions likely to be seen by the device, and the test should be designed to sufficiently stress the device to validate the effectiveness of the risk mitigation.

7.3.6 Operating and Maintenance Procedures

7.3.6.1 Risk mitigations that rely upon processes and procedures should be validated during commissioning to ensure readiness to support initial start-up.

7.3.6.2 Operating procedures for high-risk machinery should be finalized prior to initial start-up to enable time for training and for operators to become familiar with the procedures. Training should include how the procedure relates to risk reduction. Procedures should be reviewed during commissioning and initial start-up to ensure they can be executed as written.

7.3.6.3 Work processes that relate to key mitigations identified in 6.4 (maintenance tasks, operator rounds, etc.) should be finalized prior to initial start-up to enable support functions to become familiar with the processes and to ensure that the processes are ready to support the equipment. Training should include how the process relates to risk reduction. Wherever practical, these processes should be initiated during the commissioning phase to test readiness prior to initial start-up.

7.4 Pre-start-up Safety Review

The operating company shall perform a PSSR, including any relevant input from the following:

a) PSA, PSM, and HAZOP studies,

b) preliminary risk assessment (5.2),

c) detailed risk assessment (6.2),

d) SOP,

e) MOC,

f) OEM guidelines and alerts,

g) competency and training needs (refer to Section 10).

7.5 Optional Tests

7.5.1 General

Certain machinery operational testing can be performed during the commissioning phase to reduce risk of delay or failure during the initial start-up.

NOTE Operational tests during commissioning generally do not prove the full functionality of the assembled machinery package nor allow for performance validation.

7.5.2 Steam Turbine Solo Run Testing

API 686 [8] defines the procedures and precautions for steam turbine solo runs. Any special risk mitigations related to steam turbine control or protective systems should be tested prior to the solo run. Special operating procedures specific to the turbine and control design are typically needed during solo runs and during overspeed trip testing to limit steam energy and prevent sudden acceleration in the unloaded condition.

7.5.3 Motor Solo Run Testing

API 686 [8] defines the procedures and precautions for motor solo runs. Any special risk mitigations related to motor controls or protective systems should be tested during the solo run. If the motor is equipped with a variable frequency drive (VFD), particular attention should be paid to field testing all of the VFD control and protective functions in all modes of motor operation.

7.5.4 Compressor Air and Inert Gas Testing

API 686 [8] describes commissioning procedures and precautions for centrifugal and reciprocating compressors. Air and inert gas testing provide the opportunity to test valve sequencing and protective logic before start-up on process gas. Air and inert gas test procedures should include any precautions or limits identified by the vendor and those identified in detailed design reviews.

8 Operations and Maintenance

8.1 Introduction

8.1.1 General

This section defines the requirements that ensure acceptable risk management throughout the operations and maintenance phase of API 691 Machinery. The requirements herein apply to both newly installed and legacy machinery operating in existing facilities. The evaluation period should coincide with the operator's HAZOP schedule. The API 691 work process for the operations and maintenance phase is shown in Figure 8.

8.1.2 Identification of API 691 Machinery

The identification of high-risk machinery within an existing facility begins with a thoughtful review of the operating and design context in question. Facility machinery and safety engineers will typically have previously identified critical equipment using corporate best practices. The subset of critical machinery that poses high levels of HSE risks can best be identified through examination of previous HAZOP, PSA, PSM, root cause analysis (RCA), incident reports, etc. and with analysis of the following risk factors.

a) *Hazard of Process Service*—Operating companies may use their own initial screening criteria to identify process hazards or those defined in 1.1.2.

b) *Robustness of Machine Design*—To prevent loss of containment and/or a loss of functionality that could lead to a potential process safety event. Comparing individual legacy machines to the current API 600 series machinery standard design requirements are acceptable means to assess this robustness. In risk mitigation, users may choose to make upgrades to the features in current API machinery standards.

   NOTE Gap assessments are generally performed against targeted design features affecting loss of containment and/or a loss of functionality that could lead to a potential process safety event.

c) *CM Inspection and Maintenance*—The level, quality of, and kinds of CM, inspection, and maintenance activity, and especially lack thereof, are important factors in risk. In risk mitigation, users generally choose to conduct more frequent machinery inspections and/or modify existing maintenance strategies to reduce risk.

   NOTE Annex E outlines advanced CM approaches that may provide additional risk mitigation.

d) *Protection Systems*—The types of machinery protection systems, or lack thereof, are important factors in risk. In risk mitigation, users may choose to employ a variety of protection systems.

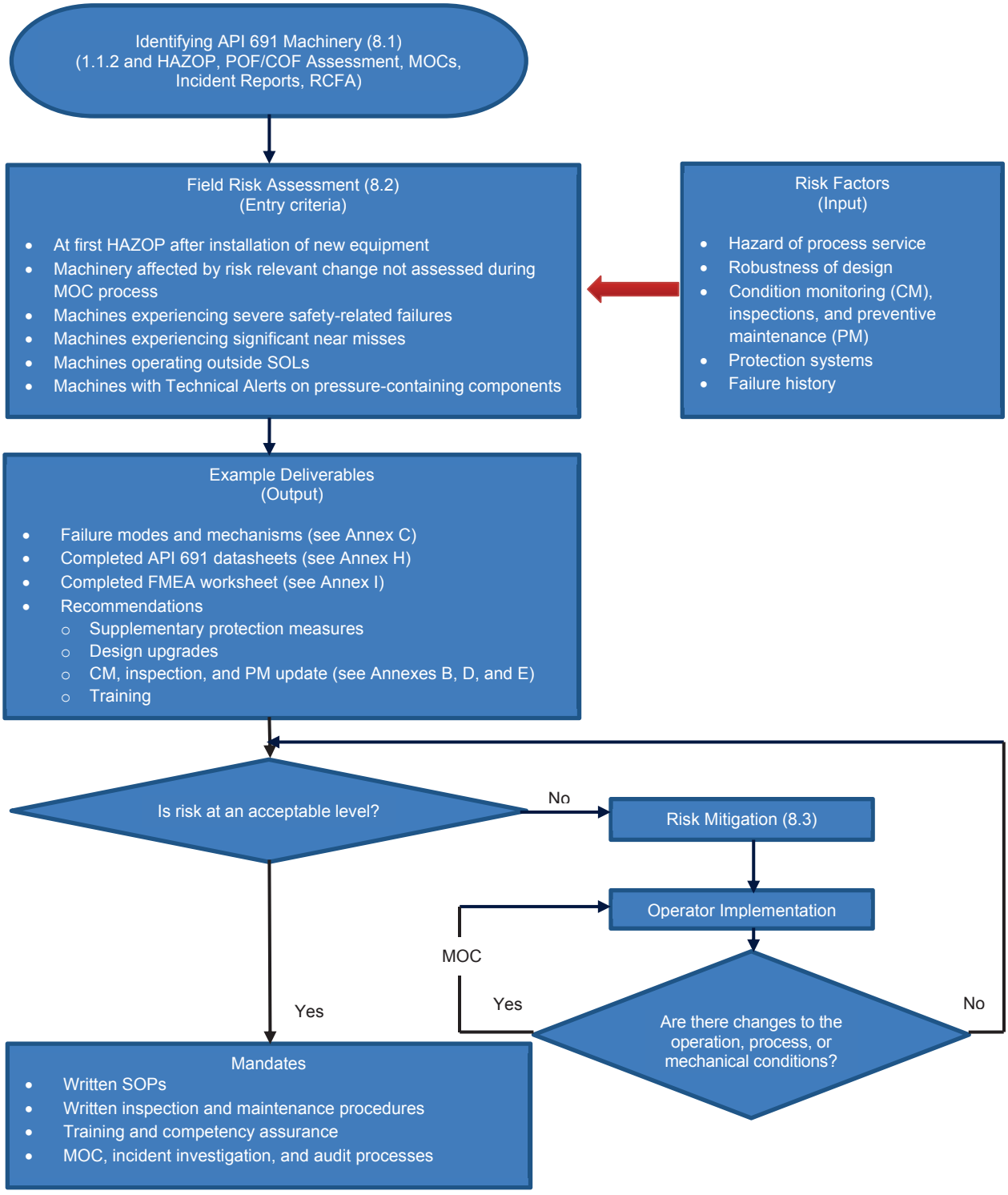


Figure 8—API 691 Work Process During the Operations and Maintenance Phase

e) *Post-lost-of-containment Systems*—Systems that isolate leakage points, for example, remotely actuated emergency block valves, or fire control/extinguishing systems or other means of containment, neutralization, or alarm—or lack of such systems—are risk factors. Users may choose to employ these types of systems to further mitigate risk.

f) *History*—Reliability and maintenance [e.g. mean time between failures (MTBF) or mean time to repair (MTTR)] data of legacy machines are essential to conducting accurate risk assessments by defining the

POF and COF. Caution is warranted when using basic failure history results (e.g. MTBF) because it alone does not provide the causative factors on which the data are based and may not contain a worst-case COF. Details of failure history should be considered when performing risk assessment.

NOTE 1 Historical operations and maintenance data are often inputs to PHAs. PHAs provide additional information in identifying high-risk machinery. When history is used as a factor in establishing risk, the accuracy and completeness of data is critical.

NOTE 2 When no actual machine history is available, users may judiciously consider using the history of similar or identical machines in the application to assess risk.

8.2 Field Risk Assessments

8.2.1 The field risk assessment is an evaluation of risk based on the process and machine conditions including installation, operation, inspection, and maintenance. The focus of this section is on identifying risks that may occur because of actual variances between intended design and actual operating conditions.

8.2.2 The purpose of the field machinery risk assessment is to identify any new or previously unidentified risks at the maintainable item level, such that specific, focused tasks or other actions can be taken to mitigate unacceptable (high) risks. The field machinery risk assessment also enables the operator to:

a) update the risk ranking of in-scope machinery within the operating facility,

b) identify and mitigate any changes in risk categorization or risk ranking since previous risk assessments,

c) determine whether the equipment is capable of performing its intended function.

Field risk assessment may be done in concert with other risk assessment processes (e.g. HAZOPs, MOC, risk-based strategies). The depth of review and methods used for a specific field risk assessment will be dependent on the complexity of the issues (e.g. machine type and operating context), level of potential risk, and what triggered the need for the assessment. Operators may use their own risk assessment methodologies. In the absence of internal requirements, the use of PFMEAs is recommended (refer to Annex A). For a short list of specific deliverables for a typical risk assessment, refer to 5.2.3.1.

8.2.3 The operating company or their DRP should gather the following information (if available) prior to performing a machinery risk assessment:

a) available process operating trends, both steady state and transient such as start-up, shutdown, upset, and other off-design conditions,

b) process flow diagrams (PFDs),

c) P&IDs,

d) HAZOP, PSM, or PSA documentation,

e) as-installed API datasheets,

f) machinery performance curves,

g) equipment failure history,

h) IOWs,

i) SOLs,

j) DFMEA,

k) PFMEA,

l) CM data,

m) safety integrity level (SIL) studies.

NOTE 1 Operating companies will also find the following information useful in performing a field risk assessment:

a) technical advisory alerts,

b) what-if studies,

c) RAM analysis,

d) redundancy study,

e) ALARP analysis,

f) bow tie analysis,

g) RCM,

h) RCA,

i) layer of protection analysis (LOPA).

NOTE 2 Information can be difficult to collect for legacy machinery. Paper copies of information for machinery that has been in operation over a long period of time is often discarded or misplaced. The intent of 8.2.3 is not to burden the operating company or the vendor in retrieving the listed data, analysis, etc. if it is missing; nor is it the intent to delay the timely completion of risk assessments. The lists above are offered as guidance to the operating company undertaking a machinery field assessment.

8.2.4 If materials of construction for pressure-containing components are unknown for legacy machinery operating in services outlined in 1.1.2, then positive material identification (PMI) should be determined by the operating company prior to conducting a field risk assessment.

NOTE The intent of this requirement is not to shut down machinery simply because there is no PMI on pressure-containing components but to confirm the PMI at the first available opportunity (overhaul, TA, etc.) if there exists no documentation on file.

8.2.5 Machinery meeting API 691 criteria shall have a field risk assessment if/when any of the following apply or occur.

a) Newly installed API 691 Machinery. The field risk assessment shall be made during the first HAZOP following installation.

   NOTE Although risk mitigation requirements may have been implemented for all API 691 equipment for earlier phases of the equipment life cycle, the start of the operations and maintenance phase is often accompanied by unanticipated hazards. There exists uncertainty within the process, the machinery, and the work force within the newly built plant. Process conditions may be very different than what designers had assumed during FEED or detailed design. These in some cases invalidate assumptions that can place greater stress on machinery causing failure. In other cases, the initial machinery design assumptions themselves can be proven to be incorrect, which without appropriate safeguards and training can prove to be catastrophic. There are unexpected component failures from infant mortality issues that can overwhelm an inexperienced work force who may still be learning their roles and responsibilities.

b) Machinery affected by a risk relevant change.

   NOTE Machinery that has recently experienced a major change to the process, system, or components such as may occur during a TA, repair, rebuild, or upgrade. Such potential changes would include, for example, a change from sweet to sour service, change in pH, pumped abrasive content, temperature, pressure, hydrogen partial pressure, etc.

c) Machinery that has sustained moderate to severe safety failure consequences as defined by the operator.

NOTE Guidance can be found in API 689, First Edition, Table C.1, Consequences I–IX [16].

d) Machinery that has experienced a significant near miss with potential for severe failure consequences as defined by the operator.

NOTE Guidance can be found API 689, First Edition, Table C.1, Consequences I–V [16].

e) Machinery found to be operating outside of the SOL criteria.

f) Machinery that has received a technical alert issued by the vendor or subvendors that highlights component or subcomponent flaws that may lead to release of a highly hazardous material or other hazardous condition.

g) Machinery identified in 8.1.2 with potential high risk that has not previously had a risk assessment performed.

8.2.6 Field risk assessments may be conducted using a variety of approaches. See Annex A for representative examples.

8.2.7 Companies may consider the need to implement this recommended practice across multiple facilities. The following facility descriptions may be useful in determining the resource requirements required to successfully address risk-based machinery management across an organization.

a) New facilities that have performed the activities prescribed earlier in this recommended practice.

b) New facilities that have not performed all of the prescribed activities and/or do not have a clearly defined risk ranking or risk mitigation strategy.

c) Existing facilities that have an up-to-date risk analysis and risk-based strategy for operation and maintenance that were developed using methods other than those prescribed in this recommended practice.

d) Existing facilities without a representative and/or up-to-date risk categorization and risk management strategy.

e) Existing facilities that have undergone significant changes that may require a reevaluation of machinery risks.

f) Existing facilities that may be maturing or have aging equipment that may require additional activities to mitigate risks.

g) New or existing facilities that have programs such as RCM or total productive maintenance (TPM) but have plants where RCM studies have not been completed.

8.3 Risk Mitigation

8.3.1 The field risk assessment determines whether mitigations are needed to achieve an acceptable level of risk and provides the operator with a list of recommended actions including their corresponding expected risk reduction (COF and POF) levels.

8.3.2 Risk mitigation may include one or more of the following:

a) reducing the hazard of the process (less hazardous chemicals, reducing the rates of degradation, mitigating damage mechanisms, etc.),

b) hardware upgrades to the machine proper (upgrades to features in the latest API machinery standards, upgrades that make the machine robust against loss of containment and/or a loss of functionality that could lead to a potential process safety event, etc.),

c) performing repairs per API 687 [17] where applicable to machine type,

d) predictive and preventative maintenance (refer to 6.4.2),

e) enhanced CM and diagnostics (Annex E),

f) machinery prognostics (Annex F),

g) protection systems, interlocks (such as used for lubrication, vibration, surge),

h) post loss-of-containment systems (remotely operated isolation valves, fire suppression and deluge, loss-of-containment monitor alarms),

i) reliability upgrades (upgrades that reduce POF such as moving machine design to better fit window of operation including all operational phases such as start-up, upsets, shutdown, improvements in bearing and seal lubrication quality),

j) increased inspection intervals and scope (refer to B.5.3 addressing additional pressure boundary inspections for machinery in corrosive, erosive, and harsh service),

k) risk-based maintenance activities (refer to Annex B and Annex D),

l) optional field testing on the process gas (refer to 5.9.6 and 8.3.6).

NOTE Jurisdictions may require that mitigation be carried out to ALARP and in some cases that the best available technology (BAT) be considered to achieve risk mitigation goals.

8.3.3 The operating company should consider performing data collection and analysis for API 691 Machinery in accordance with API 689 [16], company overlay, or similar best practice.

8.3.4 The significance of the frequency, extent, and duration of IOW's excursions should be properly evaluated by the operating company. Risk mitigation actions addressing observed exceedances of process IOWs or machinery SOLs may include the following:

a) changing process set points,

b) modifying the process design,

c) revising SOPs,

d) reducing the time to the next inspection or overhaul,

e) improving inspection methods,

f) installing additional alarms/interlocks,

g) requiring additional operator training.

NOTE 1 Performing an engineering evaluation can expand the IOW and SOL range.

NOTE 2 For IOWs, the operator can evaluate the time weighted average of operation outside established ranges and windows. Occasional excursions outside preferred ranges may or may not pose a significant risk and should be evaluated on a case-by-case basis by the operating company.

8.3.5 The execution of all strategies and tactics to achieve risk mitigation for API 691 Machinery should be analyzed, documented, and stored as part of a continuous improvement process.

- **8.3.6** If specified, following initial start-up for new or rerated API 691 Machinery, the operating company shall conduct a field performance test to validate IOWs and risk reduction strategies developed and applied during FEED, detailed design phases, and/or operating and maintenance phases.

The field performance test also provides baseline operating data with the machine in the as-new condition to enable future CM.

NOTE The field performance test does not replace the factory performance test. If the field performance test is for contract guarantee purposes, additional instrumentation and procedural considerations may be necessary to achieve desired accuracy (refer to 5.9.6).

8.3.6.1 The extent of vendor participation depends on the purpose of the test and complexity of the machinery. Where multiple parties are involved (vendor, operating company, etc.), agreement on test purposes, procedures, safety requirement, and responsibilities should be reached prior to the commencement of testing. The following information provides input to the agreed procedures and operating targets:

a) factory acceptance test data (mechanical run test, performance test, string test);

b) process and instrumentation diagrams for all systems supporting the machine train;

c) OEM installation and operations manuals;

d) predicted performance curves (or existing test curves);

e) flow meter information: pipe internal diameter (ID), orifice bore or beta ratio (for orifice meter), K-factor (for turbine or vortex shedding meter), flow coefficient (for annubar or nozzle), and scaling frequency;

f) configuration log (for ultrasonic meter or to adjust turbine or mass flow meters);

g) performance data, such as factory test data and predicted performance;

h) piping geometry and test instrumentation.

8.3.6.2 The following items should be confirmed during the pretest checkout.

a) That the unit has been proven suitable for continuous operation.

b) If start-up strainer is installed in the inlet pipe, the strainer should be checked for cleanliness, either by use of a differential pressure gauge, direct inspection, or by borescope inspection.

c) All instrumentation should be calibrated in the range in which it will be operated during the test. Check all instrument readings for temperature, pressure, flow, torque, and speed to assure that the sensors are functioning properly.

d) Verify data acquisition system operation and setup prior to starting the field performance test. Data acquisition frequency should be consistent with analysis needs for validation of proper system response. For example, very high frequency data should be captured during machine start-ups, shutdowns, load or speed transients, and surge testing. Lower frequency data are acceptable for steady state monitoring during the extended performance test.

8.3.6.3 At completion of the field performance test, the following should be performed:

a) All temporary infrastructure, instrumentation, etc. should be removed and machine prepared for unrestricted operation.

b) Data from the field performance test should be permanently archived in a format that will ensure availability to support future operation or risk assessment activities.

c) Results from field performance test data reduction and analysis should be produced and agreed upon by all affected parties (operating company, vendor, and DRP).

8.4 Operating Company Implementation

8.4.1 The operating company shall implement risk mitigation measures identified in the field risk assessment to achieve the company defined acceptable risk level. To facilitate sustained risk mitigation over the remaining useful life (RUL) of the asset, the operating company should implement a management system meeting the requirements of 1.2.2. In addition, the following routine checks should be made on all API 691 Machinery:

a) verify written SOPs for start-up, operation, and shutdown are available,

b) review operating procedures to make sure they include steps necessary to mitigate risks and maintain SOLs/IOWs at all times,

c) confirm written maintenance procedures exist outlining preventive measures and system checks to ensure the proper functioning of protective shutdown devices,

d) ensure that current inspection, maintenance plans, and procedures are in place based on existing process and mechanical operating conditions,

e) verify that operating and maintenance personnel roles, responsibilities, training, and qualifications are clearly defined and managed for competency assurance,

f) investigate accidents, near misses, abnormal occurrences, and failures in accordance with company procedures or API 689, First Edition, Annex C.1.10 [16],

g) confirm that nonconformances are documented and corrective actions taken in accordance with company procedures,

h) confirm that an emergency response plan is in place to address loss-of-containment events,

i) ensure that appropriate documentation (datasheets, SOPs, inspection procedures, etc.) is current and revised in accordance with the operating company's MOC process.

NOTE Suggested practice for Items a) to d) above is to periodically review as changes occur in operations, process, and mechanical conditions (MOC trigger) and the company's HAZOP schedule.

9 Documentation and Recordkeeping

9.1 General

9.1.1 The purpose of this section is to provide guidance on documentation and recordkeeping needed to properly execute risk-based machinery management throughout the facility life cycle.

Documentation that is necessary to comply with this recommended practice comes from the following three major sources.

1) PSM documentation—These documents, also referred to as process safety information (PSI) documents, are defined by regulatory and company standard requirements and are beyond the scope of this recommended practice.

2) Documentation from the API design/purchase standard (e.g. API 610) and the resulting specification.

NOTE 1 These API standards typically apply up to installation and commissioning. Details on the required documentation are found within the relevant API equipment standards.

NOTE 2 API 691 defines the use of a subset of the API documentation (noted above) through the balance of the equipment life cycle, which should be kept updated to represent the machinery as it is operating in the field.

NOTE 3 Additional documentation specified by API 691 for machinery covered in its application. The details of these are covered in each of the life cycle stage sections of this recommended practice.

9.1.2 Documentation belongs to one of the following three general classes.

1) *Working Files*—Documentation used at various stages of the life cycle but may not have long-term value; retention of documentation of this nature is not detailed herein. It is up to the user to define retention requirements of these documents. Examples of such documents are: sketches, preliminary calculations, transmittal documents, etc.

2) *One-time Files*—Documents that capture information, a condition, or event that has value in subsequent life cycle stages and potentially through the useful life of the equipment. These documents and their retention are described with one or more of the documentation sources above. Examples: equipment datasheets, inspection reports, balancing records, test reports, baseline data, etc.

3) *Maintained Files*—Documentation that is updated through different life cycle stages with a major focus for this recommended practice being on those that are to be updated to represent the as-operating condition of the covered machinery. Examples include P&IDs, equipment histories, control system data files, interlocks, etc.

9.2 Documentation During Feasibility and Concept Selection

9.2.1 Priority Documentation

The documentation that is required for the feasibility and concept selection phase includes:

a) TRC assessment report [vendor supplied (V) or operating company supplied (OC) 4.2.2];

b) summary of components or subcomponents with TRL < 7 whose failure may lead to a loss of containment and/or a loss of functionality that could lead to a potential process safety event (V, 4.3.2);

c) product qualification program guide (V, 4.4.1).

9.2.2 Optional Documentation

- If specified, the following documentation shall be provided during the feasibility and concept selection phase:

a) API 691 datasheets—Annex H (OC, 4.2.2 ; V, 4.3.2);

b) concept development stage gate report (V, 4.4.5);

c) preliminary engineering stage gate report (V, 4.4.6);

d) detail engineering stage gate report (V, 4.4.7);

e) approval stage gate report (V, 4.4.8);

f) design validation report for specific operating envelope (V and OC, 4.4.10.3);

g) facility audit report in accordance with Annex G (OC, 4.5).

NOTE The vendor is not required by this recommended practice to provide or retain any of the optional documentation listed above.

9.3 Documentation During FEED

9.3.1 Priority Documentation

The documents that are required for FEED include the following:

a) required documents from feasibility and concept selection phase;

b) HAZOP, PSM, or PSA studies (OC or DRP, 5.2.2);

c) preliminary risk assessment (OC or DRP, 5.2.3);

d) summary of supplementary protective measures (OC or DRP, 5.2.4);

e) summary of components or subcomponents with TRL < 7 whose failure may lead to a loss of containment and/or a loss of functionality that could lead to a potential process safety event (V, 5.4.4);

f) DFMEA (V, 5.6);

g) third-party verification of vendor's compliance to ISO 29001, ISO 9000, or equivalent (V, 5.7.2);

h) operations, maintenance strategies (OC or DRP, 5.8).

9.3.2 Optional Documentation

- If specified, the following documentation shall be provided during the FEED phase:

a) API 691 datasheets—Annex H (OC, 5.2.3, Note 2);

b) RAM-1 analysis report (OC or DRP, 5.3.2);

c) facility audit report in accordance with Annex G (OC or DRP, 5.7.5).

9.4 Documentation During Detailed Design

9.4.1 Priority Documentation

The documents required during detailed design include the following:

a) required documents from earlier life cycle phases;

b) detailed machinery risk assessment (OC or DRP, 6.2);

c) finalized P&IDs (OC or DRP, 6.2.3);

d) finalized equipment datasheet (e.g. API 610 datasheet) (OC or DRP, 6.2.3);

e) comments and exceptions to API standards (V, 6.2.3);

f) DFMEA (V, 6.3.2);

g) IOWs (V, 6.6.1);

h) SOLs (OC or DRP, 6.6.1);

i) commissioning plan (OC or DRP, 6.8);

j) finalized cause and effects matrix (OC or DRP, 6.8.2);

k) SOPs (OC or DRP, 6.9).

9.4.2 Optional Documentation

- If specified the following documentation shall be provided during the detailed design phase:

a) API 691 datasheets—Annex H (OC or DRP, 6.4.1);

b) RAM-2 analysis report (OC or DRP, 6.5);

c) facility audit in accordance with Annex G (OC or DRP, 6.7.4);

d) major repair procedures (V, 6.7.2);

e) welder PQR (V, 6.7.3).

9.5 Documentation During Installation and Commissioning

9.5.1 Priority Documentation

The documents that are required during the installation and commissioning phase include the following:

a) required documents from earlier life cycle phases;

b) changes under the MOC process to required documents for earlier life cycle phases;

c) commissioning procedures (OC or DRP, 7.3.2);

d) functional safety test reports (OC or DRP, 7.3.3);

e) process safety valve test reports (OC or DRP, 7.3.4);

f) operations and maintenance procedures (OC or DRP, 7.3.6);

g) PSSR (OC or DRP, 7.4).

9.5.2 Optional Documentation

- If specified, the following documentation shall be provided during installation and commissioning phase:

a) API 686 deliverables (OC or DRP, 7.2.1) [8];

b) optional test reports (OC or DRP, 7.5).

9.6 Documentation During Operations and Maintenance

9.6.1 Priority Documentation

The documents that are required during the operations and maintenance phase include the following:

a) required documents from earlier life cycle phases;

NOTE Legacy documentation for existing machinery operating in the field may not be available.

b) changes under the MOC process to required documents for earlier life cycle phases;

c) field risk assessments (OC or DRP, 8.2.5);

d) qualification records (OC, 10.2).

9.6.2 Optional Documentation

- If specified, the following documentation shall be provided:

a) RAM data base (OC, 8.3.4);

b) field performance test report on process gas (OC or DRP, 8.3.6).

NOTE Additional documentation that may be useful include basic equipment data and inspection history critical to the assessment, e.g. operating conditions, materials of construction, service exposure, corrosion rate, inspection history, and machinery condition and performance:

a) operative and credible damage mechanisms,

b) criteria used to judge the severity of each damage mechanism,

c) anticipated failure mode(s) (e.g. breakdown, noise, overheating, vibration, structural deficiency, or leak),

d) key factors used to judge the severity of each failure mode,

e) criteria used to evaluate the various consequence categories, including safety, health, environmental, and financial,

f) risk criteria used to evaluate the acceptability of the risks.

10 Training and Qualification

10.1 Operation and Maintenance Training

10.1.1 Operating companies should develop a training program suitable for their facilities required skill sets and competencies. The training program should incorporate objective performance feedback for trainees and may include the following options:

a) network-based self-training,

b) network-based remote interactive training (instructor/operator training and mentoring),

c) local interactive training (instructor/operator training and mentoring).

10.1.2 Training should incorporate preconfigured or online training scenarios to be used by operators (trainees) for the various API equipment types covered by this recommended practice. This program should allow operators to be familiar with operating best practices using plant standard models, specific customized models, and specialized course curriculum. These best practices should incorporate operations, reliability, and safety best practices from within the operating company.

10.1.3 Training scenarios for operators may include the following:

a) steady state operation,

b) cold start-up,

c) hot start-up,

d) random alarms/failures,

e) load changes,

f) process upsets,

g) scheduled and emergency shutdown,

h) off-spec product,

i) over limit PVs,

j) feed content changes.

10.1.4 The training program may utilize a simulation model engine capable of operating in near real time. If a simulation model engine is used, operators should be able to monitor typical process variables and manipulate process controls without delay in the model(s). The simulator should react promptly to process transients to avoid multiple corrective actions from the operator that could inadvertently compound an upset or create an abnormal condition because of time-lag in displayed process information.

10.2 Proof of Qualification

The operating company should ensure that all operations and maintenance personnel working on API 691 Machinery are qualified using internal or third-party criteria and testing methods. Qualification records should be retained for the duration of the workers employment within the operating company.

Annex A
(informative)

API 691 Risk Assessment Methodology

A.1 Introduction

A.1.1 This annex provides guidance on recommended risk assessment methodologies that support the risk management requirements of this recommended practice as applied to each stage in the life cycle of API 691 Machinery.

A.1.2 This annex applies to companies that are considered within the following levels of maturity in the development of their risk management systems:

a) minimal or no formal risk assessment methods or processes defined,

b) formal risk assessment methods are defined for corporate requirements only and not cascaded to process system or equipment level,

c) risk assessment methods are in place, but not specifically to the level required in API 691,

d) risk assessment methods are in place, but not for new technology selection or qualification,

e) risk assessments have not been performed on new or existing equipment,

f) to supplement existing risk management methods.

This annex does not apply to companies with well-established risk assessment methodologies and criteria that can be used to support the requirements of this recommended practice.

A.1.3 Risk assessment methods considered applicable to machinery are listed in the Table A.3. The specific use of each risk assessment technique is provided as guidance to users in the absence of company standards and practices. All techniques are recognized risk techniques considered as part of the implementation of a PHA as defined in OSHA 1910 or similar international standards and practices. Techniques in Table A.3 are used for:

a) identification of risks associated with a hazard event, or

b) analysis of risk to understand hazard events and failure modes, or

c) estimation of risk by qualitative or quantitative method, or

d) ranking of risk order to understand the relative importance and priority of risks, or

e) a combination of the above.

Other specialized techniques can be used as required over the basic methods identified in this recommended practice at the owner's option.

A.2 Risk Assessment Process

A.2.1 General

The risk assessment process for API 691 Machinery is described in Figure A.1. While not identical, it is similar to the risk assessment process defined in ISO 12100.

The risk assessment approach depends on the stage of the machinery life cycle as defined in Table A.3. The user can apply the risk assessment process to suit the level of detail required.

In addition the criteria for risk assessment should be defined and include safety and environmental risk. Other risk criteria including financial, reputation, and cost will be based on the company requirements.

A.2.2 Risk Assessment Screening

API 691 Machinery are identified or validated at the life cycle stage using the risk method(s) selected by the user. There are several ways to screen and select API 691 Machinery. The recommended risk assessment methods included one or more of the following:

a) PHA (which includes HAZOP studies),

b) use of an industry standard that identifies specific hazardous processes, such as those listed as Class 1 in API 500 [18] or API 505 [19],

c) COF assessment,

d) risk assessment based on POF and COF using a risk matrix or RPN method or equivalent to evaluate risk.

The outcome of the risk assessment screening is a list of all the API 691 classified machinery that are subject to the risk assessment requirements in this document.

A.2.3 Define Scope of Machinery Risk Assessment

The scope of machinery risk assessment is the level at which risk analysis is applied within the user-defined boundaries of the API 691 Machinery. This depends on several factors including:

a) the stage in the machinery life cycle and corresponding risk understanding required at a particular stage,

b) the level of information available on the machinery design, configuration, components, and subcomponents,

c) the company or party applying the risk assessment process, e.g. the vendor may have a different emphasis on risk and level of applied risk than the operating company,

d) the boundary limits defined by the user on what is considered part of the API 691 machine.

Figure A.1 shows the typical scope of machinery risk assessment at each stage in the life cycle in terms of plant level: system, equipment, component, and subcomponent level. In addition, the typical company or vendor role in risk assessment at each plant level is defined.

The risk assessment methods recommended apply to both new and existing machinery and to the machinery components, subcomponents, and supporting equipment deemed to be within the machinery package boundaries.

API 689 provides guidance on defining rotating equipment boundaries and the hierarchy of components and subcomponents. The elements considered within the limits of the machinery package are at the owners' option. These may include:

a) driver and driven machinery,

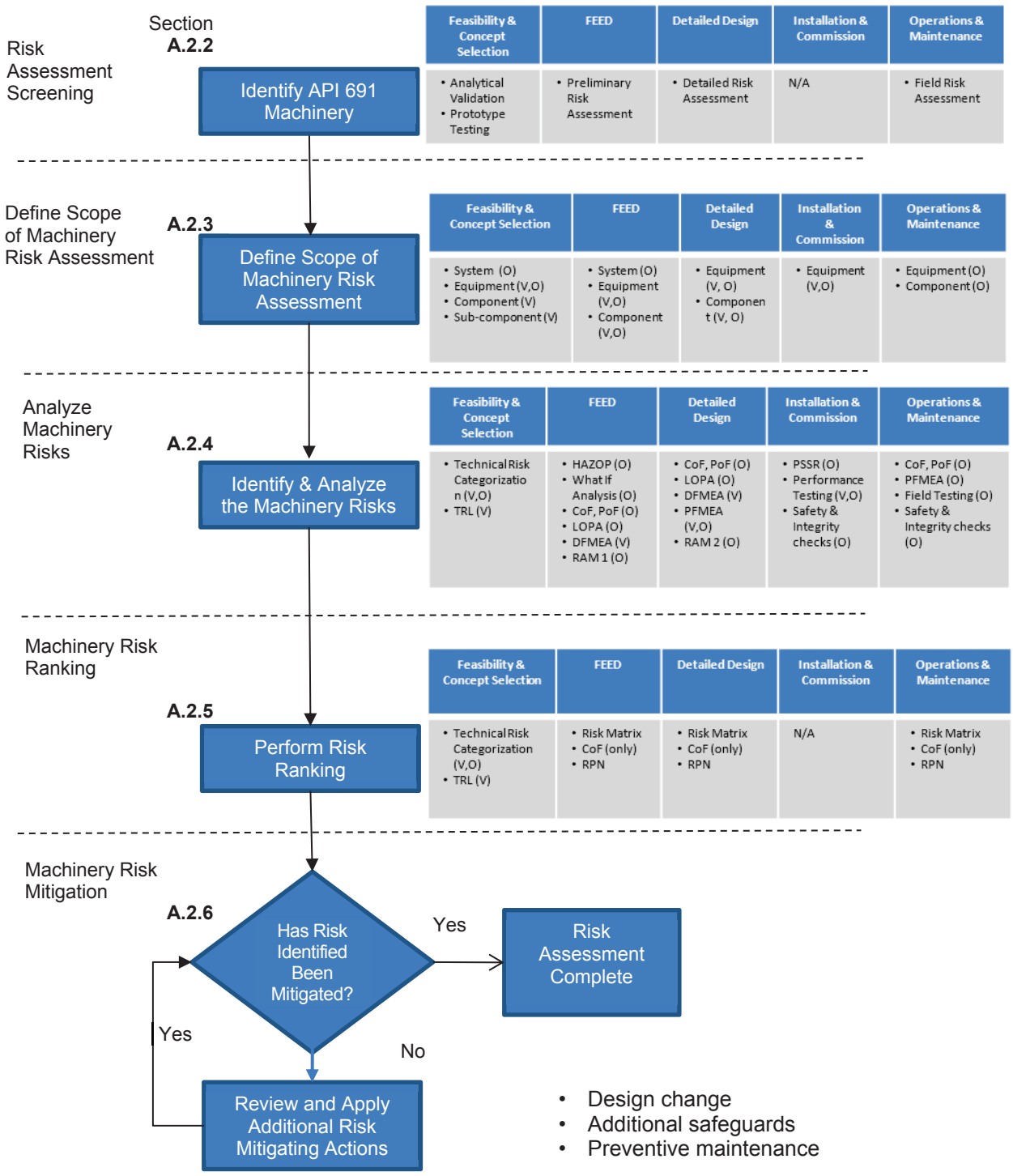
b) auxiliary equipment and systems such as lubricating oil systems,

c) control system equipment,

d) upstream and downstream process equipment such as compressor suction separators,

e) machinery instrument devices.

The machinery or equipment package limits should be defined prior to the risk assessment. This provides the scope of risk assessment in terms of the equipment included, which determines the hazards or failure modes to be reviewed. How a company frames the machinery limits will affect the outcome of the risk assessment.



NOTE 1 O—Operator or DRP contractor. V—Vendor.

NOTE 2 Designations for responsible action may differ from noted above and can be specified on the API 691 datasheet for individual applications.

Figure A.1—API 691 Risk Assessment Process

A.2.4 Analyze Machinery Risks

A.2.4.1 General

The identification of machinery risks is the first step in the analysis. Potential risks may be determined from a combination of several sources of hazard and failure knowledge and should include:

a) PHA studies, i.e. HAZOP;

b) potential failure modes checklists;

c) potential hazard checklists;

d) operating knowledge;

e) engineering studies.

Analysis of machinery risk involves the determination of the severity of the consequence of the hazard or failure and where possible the probability of the hazard or failure occurrence. This requires the user to review each hazard or failure mode associated with the machinery in a systematic process to identify the COF and POF.

An informative guide to each of the risk assessment methodologies stated in this document is provided in the following paragraphs. The user is referred to recognized industry standards for a detailed description and comprehensive application of these methods.

Table A.3 identifies the relevant standards for reference related to each stage in the machinery life cycle.

A.2.4.2 Checklist Analysis

Checklist analysis is based on the compilation of a suite of experience-based questions to verify that a system or equipment or component or task meets the user required level of risk. The process to develop a checklist and conduct a risk assessment includes the following steps.

a) Define the boundary of the system to be reviewed, which should be the machinery limits.

b) Determine which type of hazards are to be analyzed, which should include safety and environmental as a minimum.

c) Subdivide the system or equipment into subcomponents at an appropriate level.

d) Generate a checklist of safety-based questions focused on risk focus.

e) Respond to questions with recommended actions to mitigate safety issue.

An example of the type of safety question and response is shown in Table A.1.

Table A.1—Example Safety Question and Response

Checklist Question	Response	Recommended Actions
Is there a risk of bearing failure?	Bearing could fail and overheat shaft Potential to release high energy projectile	Install temperature and vibration sensors Check L10 life Verify vendor quality report

PSSR checklists are another form of checklist assessment used to review pre-start-up readiness and safety condition on process systems and machinery units.

Checklists vary in format and depend on the risk assessment purpose. The Technical Risk Classification (Table A.2) is another example of a checklist-based risk assessment.

In all cases this risk method is qualitative but can provide limited risk ranking information.

A.2.4.3 What-if Analysis

A “what-if” analysis is a process that defines potential failure scenarios based on the experience of a team of experts in machinery. The risk assessment is a qualitative method and includes the following key steps.

a) Define the boundary of the system to be reviewed, which should be the machinery limits.

b) Determine which type of hazards are to be analyzed, which should include safety and environmental as a minimum.

c) Subdivide the system or equipment into components and subcomponents at an appropriate level.

d) Generate a list of “what-if” questions for each component or subcomponent.

e) Complete the risk assessment by answering the “what-if” question by identifying the consequences with no risk measures, possible safeguards, and mitigating recommended actions.

NOTE The method is a hazard assessment technique that relies on the creative thinking of a select team of specialist.

A.2.4.4 Hazard and Operability Analysis

HAZOP is a PHA method used primarily to identify major process hazards and operability issues. The method is defined in the standard IEC 61882 [20] as an application guide for the identification of risk, risk analysis, and risk mitigation recommendations related to the process design.

In a HAZOP the terms of reference are established to determine which section of plant or system is to be examined. The following key process steps are facilitated by a HAZOP leader and applied to a single line or section on the P&ID reviewed.

a) Identify deviations from design intent using guide words on each element.

b) Identify the consequences and causes.

c) Determine whether significant problems exist.

d) Identify protection, detection, and indicating measures.

e) Identify possible remedial/mitigating measures.

This process is repeated for each element on the P&ID systematically until all risks have been documented for the system reviewed.

The results from the HAZOP review are risk-ranked causes of process parameter deviation from the design intent and associated recommendations for reducing risk through safeguards.

The analysis provides a mechanism to screen machinery within systems and identify API 691 Machinery. It also provides valuable hazard and potential failure information for further risk analysis such as FMEA and fault tree analysis (FTA).

HAZOP is a system centered approach compared to FMEA, which is a more component centered analysis.

A.2.4.5 COF and POF Method

The hazard or failure occurrence probability POF should be defined either qualitatively or quantitatively in predefined ranges or categories. In a similar fashion, the severity of a hazard event or failure COF should be defined for each category of consequence considered.

As a minimum, safety and environment should be used in the assessment of risk. At the users' discretion, other risk consequence categories may be applied such as financial, reputation, and cost.

Examples of typical consequence severity and failure probability scales are provided in Figure A.2 that may be used for machinery-based risk by equipment owners. Alternative POF and COF categories and ranges may apply to risk assessment by vendors at the machinery design and development stage.

The representation of the calculated risks can be done in several formats including:

a) risk matrix with COF and POF,

b) RPN,

c) Pareto graph of risks.

The format is the user company preference in terms of how risk is communicated.

This method has a common application to several risk assessment methods (HAZOP, FMEA, LOPA, etc.) by providing the basic calculation for determining the level of risk for each hazard or failure mode analyzed.

Quantitative	Qualitative	PROBABILITY						
> 1 per year	Likely to occur frequently		**5** Almost Certain	Medium	Medium	Hig	High	High
> 1 in 5 years	Will occur several times in the life of the product		**4** Probable	Medium	Medium	Medium	High	High
> 1 in 25 years	Likely to occur sometime in product life		**3** Possible	Low	Medium	Medium	Medium	High
> 1 in 200 years	Unlikely, but possible to occur during product life		**2** Unlikely	Low	Low	Medium	Medium	Medium
> 1 in 2500 years	Failure is unlikely, it can be assumed that occurrence may not be experienced		**1** Rare	Low	Low	Lo	Medium	Medium
				1 Negligible	**2** Minor	**3** Significant	**4** Major	**5** Catastrophic
				SEVERITY				
			Safety	Negligible impact or exposure	Minor injury	Serious Irreversible injury	Fatality of one to max ten people	Fatality of more than ten people
			Environment	Spill to containment or minimal release; no long-term consequences	Environmental impact is short term and contained within site; no remediation required	Environmental impact is short term; significant release; spill not contained on-site; some remediation required	Environmental impact is medium term and external to facility; major release; major remediation work	Environmental impact is long term, external to facility; very large spill; massive remediation necessary

Figure A.2—Typical Risk Matrix with COF and POF Categories

A.2.4.6 Technical Risk Categorization

Design technical risk assessment is a checklist method in design used to evaluate and classify machinery risk considering reliability, technology, configuration, operating envelope, and organizational factors. The technical risk categories in Table A.2 provide guidance to the user in identifying the particular risk category.

Category A machinery may be characterized by a high level of uncertainty, e.g. in terms of pressures and temperatures of produced fluids that are outside previous experience for development (suggesting a high level of new design and qualification may be required). Alternatively, the technology and environment may be relatively standard, but the project/product team may be inexperienced or located remotely from the primary technical resources of the company. This may include start-up company products or existing companies using new subvendors located in emerging regions of the world.

Category D machinery should be characterized by a high level of certainty in terms of environments very similar to existing projects, high likelihood of being able to use standard field proven equipment, and an experienced project team with a good understanding of technical requirements and an ability to produce a high-quality product.

The determination of machinery technical risk categories during the feasibility and concept selection stage allows both operating companies and vendors to focus their resources on high-risk machinery to satisfy the needs of the industry in ensuring a safe working environment.

Categorization should not be an onerous activity. The following ground rules should be used to facilitate the process.

a) If there is any doubt as to which technical risk category applies, select the higher risk category (and investigate the uncertainty).

b) The selected level of risk for each change factor should be accompanied with brief explanation/justification of the risk category to aid future understanding.

c) The overall category for the project/package/equipment is the highest of the categories for the individual risk change factors.

d) The definitions in Table A.2 are general and are intended to be applied at project, package, and component levels. Some interpretation for each project stage and project scope may be necessary.

Vendors of equipment should be contacted to identify technical hurdles or barriers to implementation in order to establish cost and schedule to develop a qualified system. This should then be built into the preliminary project/product schedule with sufficient schedule flexibility to account for the information.

Table A.2—Machinery Technical Risk Classification

	Technical System Scale and Complexity			Operating Envelope	Organizational Factors
	Reliability	**Technology**	**Configuration**	**Environment**	**Organization**
Risk Level	— Machine type — Service — Blading/impeller design — Sealing design — Casing design — Bearing design — Speed	— Materials — Dimensions — Design life — Stress limits — Temperature limits — Corrosion — Duty cycle	— Layout complexity — Control systems — Driver size — Auxiliaries — Side streams — Shaft length	— Facility location — Pressure — Temperature — Flow rate — Fluid properties — Design point — Normal point — Process variability — Level of competence of field personnel	— Location — Company — Resources — Contractor — Supply chain — Experience — Machinery design competency — Manufacturing capabilities — Testing capabilities — QA/QC
A (Very High)	**Reliability improvements (technology change):** A significant reliability improvement requiring change to the technology involved.	**Novel technology or new design concepts:** Novel design or technology to be qualified during project.	**Novel applications:** Configuration has not been previously applied by vendor.	**New environment:** Project is pushing environmental boundaries such as pressure, temperature, etc., new part of the world, or limits of field expertise.	**Whole new team:** New project/product team, working with new vendors in new location.
B (High)	**Reliability improvements (design change):** A significant reliability improvement requiring change to the design but no change to the technology.	**Major modifications:** Known technology with major modifications such as materials changes, conceptual modifications, manufacturing changes, or upgrades. Sufficient time remains for time remains for qualification. Nonmature for extended operating environments.	**Orientation and capacity changes:** Significant configuration modifications such as size, orientation, and layout; changes fully reviewed and tested where viable. Large scale, high complexity.	**Significant environmental changes:** Many changes noted: extended and/or aggressive operating environment; risk requires additional review.	**Significant team changes:** Project team working with new vendor or with supply chain: key technical personnel changes from previous projects.

	Technical System Scale and Complexity			Operating Envelope	Organizational Factors
	Reliability	**Technology**	**Configuration**	**Environment**	**Organization**
C (Medium)	**Minor reliable improvements:** Reliability Improvements requiring tighter control over quality during manufacture assembly and fabrication.	**Minor modifications:** Same vendor providing a copy of previous equipment with minor modifications such as dimensions or design life; modifications have been fully reviewed and qualifications can be completed.	**Interface changes:** Interface changes, equipment or control systems changes; where appropriate configuration has been tested and verified.	**Similar environmental conditions:** Same as previous project or no major environmental risk have been identified.	**Minor team changes:** Small or medium organization; moderate complexity; minor changes in contractor/vendor and project team.
D (Low)	**Unchanged reliability:** No reliability improvements required, existing QA and control is acceptable.	**Field proven technology:** Same vendor providing equipment of identical specification manufactured at the same location; provide assurance no changes have occurred through the supply chain.	**Unchanged:** Configuration is identical to previous specifications; interfaces remain unchanged, with no orientation or layout modification.	**Same environmental conditions:** Same as recent project.	**Same team as previous:** Same project team, contractors, vendors, and vendors supply chain; applies throughout project life cycle.

A.2.4.7 Failure Modes and Effects Analysis

FMEA is a method of risk assessment that can be applied at equipment, component, and subcomponent levels on API 691 Machinery.

The FMEA process is defined in IEC 60812 [6] using a systematic approach to identify for each functional failure:

a) the potential failure modes,

b) the consequences or effects associated with each failure mode,

c) the potential causes of failure,

d) the controls or safeguards applied to mitigate failures,

e) the detectability of controls and how well they are expected to perform (refer to the Annex I FMEA worksheet for example scale),

f) calculation of a RPN based on COF, POF, and detectability determination,

g) recommended mitigating actions.

The process is typically conducted using a FMEA form to structure the information gathering and analysis. A FMEA worksheet is included in Annex I. An extension of the FMEA method to incorporate a quantification of risks associated with each failure mode is termed failure mode, effects, and criticality analysis (FMECA).

Several forms of FMEA exist, including functional, design, and process FMEA. Design FMEA (DFMEA) examines risk associated with equipment and component failures. Process FMEA (PFMEA) considers risk associated with work processes including failures, e.g. in the manufacturing or assembly process.

A.2.4.8 Layers of Protection Analysis for Machinery

LOPA is a structured risk analysis that normally follows a qualitative PHA such as HAZOP. The method is defined in IEC 61511 Part 3, Annex F (informative) for the process industries.

LOPA requires the user to determine and quantify the risk associated with various hazard events identified by the PHA using the severity of the consequences and the probability of the events being initiated. The residual risk after several layers of protection are considered is calculated to meet company risk reduction requirements. The LOPA risk assessment process is shown in Figure A.3.

The following describes the basic steps of a LOPA:

a) *Determine the Hazardous Event*—The user determines the various hazardous events associated with operation of high-risk machinery. These events are typically those identified in the user's process safety analyses, along with any additional credible hazards identified by the user as potentially leading to consequences that are above company defined risk thresholds.

b) *Determine Event Severity and Consequence*—The potential, undesirable consequences resultant from exposure to each hazardous event are identified. These consequences are typically used as identified in the user's process safety analyses. The appropriate COF category is assigned for any events not covered by the process safety analyses.

c) *Determine Initiating Causes*—All of the credible causes of the initiating event are then identified by the user. Causes are typically aligned with those identified in the user's process hazard analyses.

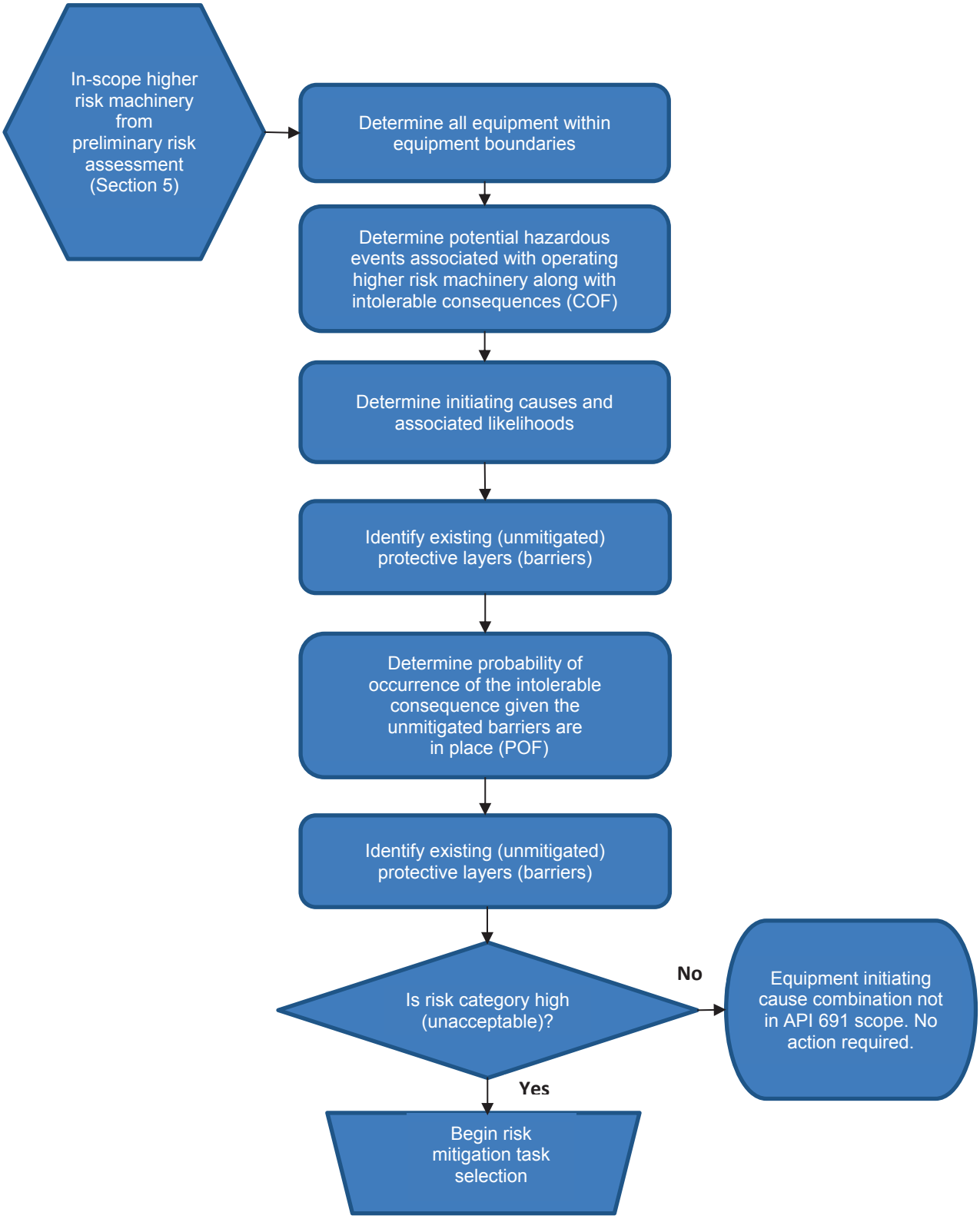


Figure A.3—Detailed Risk Assessment Process Utilizing a LOPA

d) *Determine Likelihood of Initiating Causes*—An estimate of the probability of each initiating cause, POF.

NOTE The Center for Chemical Process Safety (CCPS) should be consulted for initiating event frequency information.

e) *Identify Existing Layers of Protection*—The independent protection layers (IPLs) such as mechanical devices, barriers, or protective instruments are identified for each hazard event. The level of protection provided by the IPL is quantified by the probability that it will fail upon demand.

f) *Determine the Requirement for Additional Mitigation*—Using the probability of the initiating cause, and the existing layers of protection IPL (unmitigated), the user determines the POF category, defined as the likelihood a given initiating cause will lead to an identified intolerable consequence.

LOPA is typically performed using an analysis worksheet.

LOPA may be graphically displayed using the bow tie diagram to provide visual clarity to the provision of barriers used to mitigate potential hazard events as shown in Figure A.4.

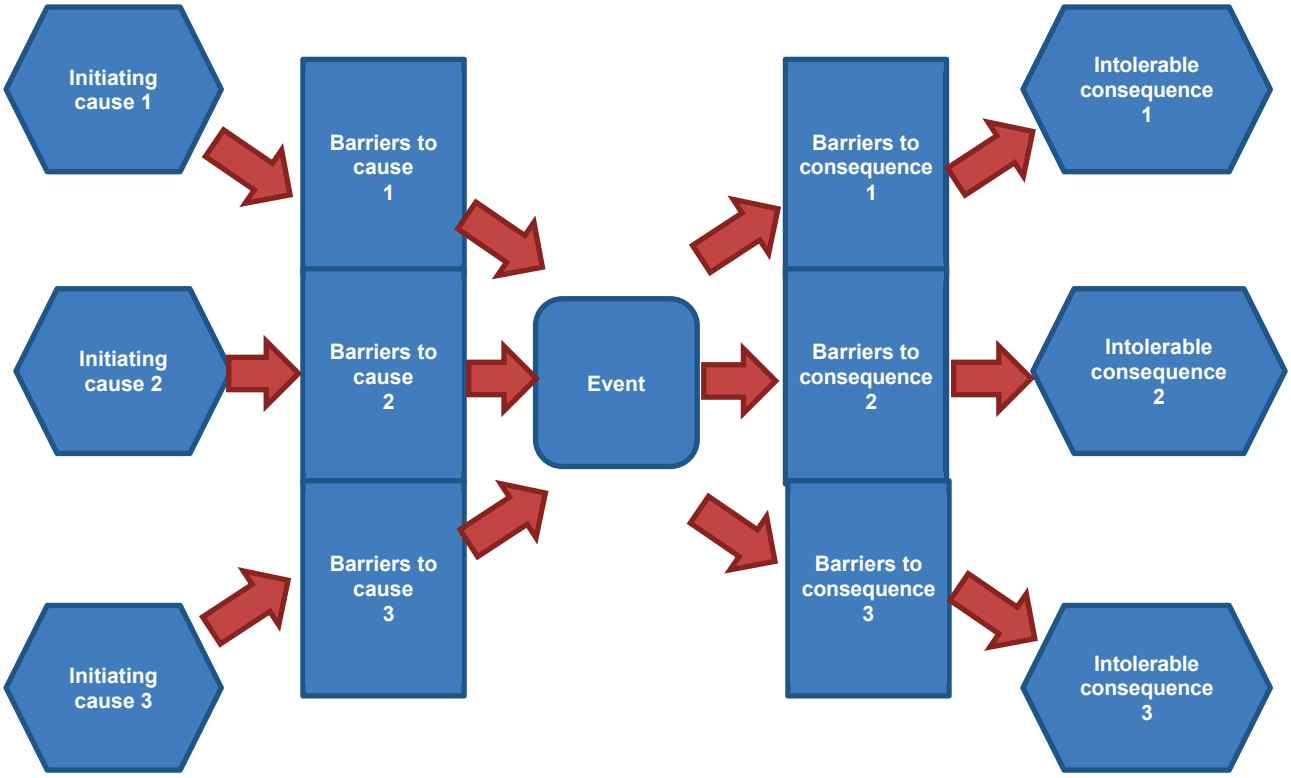


Figure A.4—LOPA Depicted Using Bow Tie Diagram

A.2.4.9 Reliability, Availability, and Maintainability Analysis

A.2.4.9.1 The principal objectives of RAM analysis include the following.

a) Evaluate the ability of the system to operate at acceptable risk levels.

b) Support the definition of the maintenance or intervention support strategy.

c) Represent the combined reliability analysis and modeling effort in operational terms.

d) Determine the availability probability value (APV), which can be an indicator of production capability. APV is often used in economic analysis to determine the impact of the present design on production, or it can be

used to compare two or more competing options. The economic model is derived from plant inputs or estimates of the capital, procurement, installation, disposal, operating, and maintenance costs.

e) Identify and rank the contributors to production losses.

f) Maintenance policy such as number of repair teams, rig mobilization policy, spare parts management, and repair priority in case of simultaneous failures.

RAM analysis provides a forecast of equipment and/or facility (system, unit, refinery) production availability using statistical methods and is the means for quantifying the future performance of any system in terms of key performance indicators (KPIs) such as availability, production efficiency, utilized capacity, gross sales or profit, missed or late shipments, flaring events, etc. It addresses the production system performance and design improvement opportunities to close production deficiencies in a cost-effective manner.

A.2.4.9.2 RAM models are primarily based on the use of reliability block diagrams (RBDs) in which the probabilities of equipment and component failure is modeled as failure distributions. These are solved using analytical techniques or through probabilistic simulation.

RAM analysis involves the application of both analytical and simulation models of the machinery or more commonly the entire process system or systems.

An analytical model for system reliability would be the system's probability density function as a function of individual failure distributions of the various components. As the complexity of a model increases (e.g. number of components or pieces of equipment, repairs, resources utilization, etc. increases), it becomes more challenging to employ analytical models.

Complex systems with a multitude of stochastic components can be represented more accurately with simulation models.

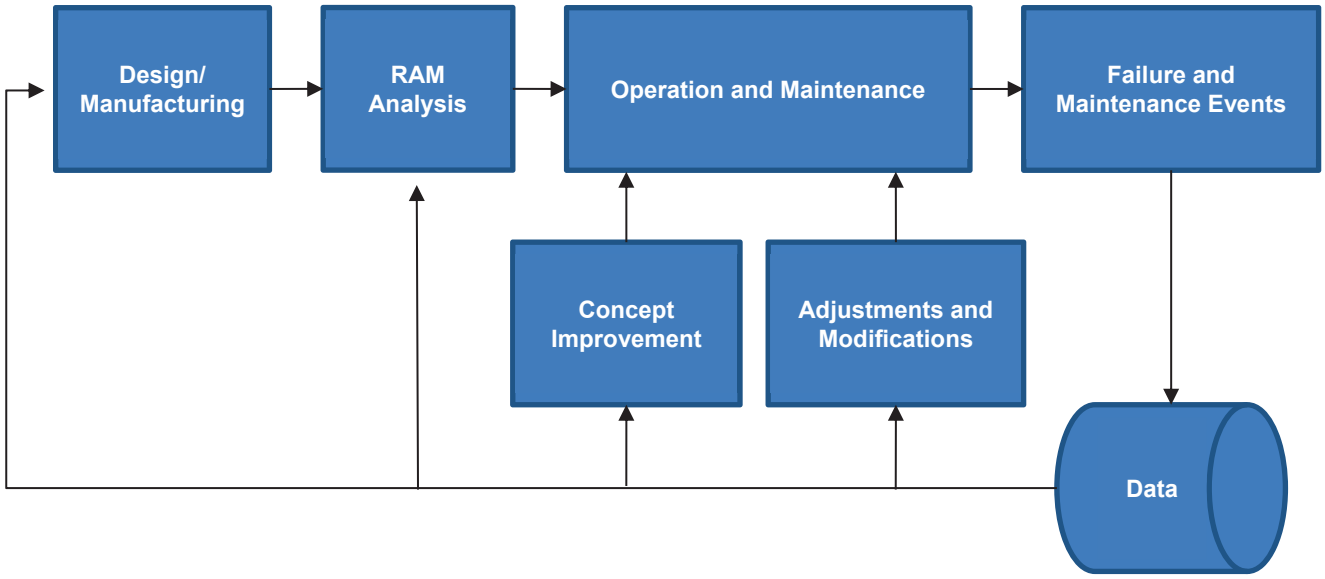


Figure A.5—Typical Feedback of Analysis from Collected Reliability and Maintenance Data

While this recommended practice addresses risk-based machinery management, it is often necessary to perform RAM analysis at the system, unit, or plant level (see Figure A.5) encompassing all asset types in order to:

1) properly define machinery risk in terms of production loss, and

2) to accurately quantify the appropriate sparing, spare parts inventories and maintenance strategies.

RAM analysis can be carried out during FEED for an entire plant, process unit, system, or during detailed design at the individual equipment level (RAM-2 analysis—see 6.5) including all maintainable components. The extent to which RAM analysis is conducted depends on several factors including perceived criticality, size, scope, and economic value.

A.2.4.9.3 RAM analysis should take into consideration design and manufacturing specifications, process conditions, and failure and maintenance data as shown in Figure A.5.

A.2.4.9.4 RAM analysis consists of:

a) logic dependency constructs (block diagram, Petri nets, conditional logic) that describe the impact of the behavior of a single item on the behavior of a group of items (i.e. the impact that the failure of a seal will have on the functioning of a pump or that the failure of a pump will have on the output of a unit, etc.),

b) failure rates or failure distributions that describe the probability that an item will not be able to fulfil its intended function,

c) repair rates or repair distributions that describe the probability that an item will be repaired and return to operation within a given period of time.

Frequency and duration of nonequipment related events such as planned TAs, unit turndowns, weather, etc. can affect equipment and system behavior.

A.2.4.9.5 Data collection and validation is recommended in accordance with API 689 and/or ISO 14224. [16]

NOTE Existing data taxonomy structures within most operating companies were set up prior to the publication of API 689. This recommended practice provides a uniform structure to exchange reliability and maintenance data. To the extent that companies collect data in accordance with this recommended practice, they are better able to make better use of it as it is tied to key analysis utilized by major oil and gas companies.

Poor data quality is one of the significant reasons for erroneous RAM model results. If companies are able to institute comprehensive and uniform data collection and validation that is noncompliant with API 689, it may achieve the same objective analytically; however, it may limit the company in performing external benchmarking that has been proven to be useful to numerous companies worldwide.

For existing installations, current operating condition and historic failure data are typically used to determine the appropriate failure and repair distributions to be used in the model. When those data are not available or inconclusive, then data from identical or similar equipment may be used.

A.2.4.9.6 The user should utilize maintainability data that are representative of the facility being modeled including but not limited to the following:

a) shutdown and access times (scaffolding, rigging, cooldown, isolation, decontamination, etc.),

b) PM/CM time durations,

c) warehouse parts ordering times,

d) active repair time,

e) spare parts availability,

f) experience level of maintenance crew,

g) maintenance crew mobilization requirements,

h) accessibility of machinery specialists,

i) time required to test and restart system.

NOTE Model accuracy may be greatly impacted by erroneous assumptions in the facility maintenance strategy (preventative maintenance, PDM, or run to failure).

A.2.4.9.7 Additional data sources that might be used within the RAM model may include:

a) internal CMMS historical data for similar or identical machinery,

b) internal CMMS historical data for general equipment types,

c) offshore reliability data (OREDA),

d) operational reliability analysis program (ORAP),

e) North American Electric Reliability Council (NERC) generating availability data system (GADS),

f) OEM (as data quality improves, the order of preference for using these data will change),

g) other (consultants).

A.2.4.9.8 The modeling methodology employed should account for data uncertainty such that forecast availability values are expressed with histograms or uncertainty bounds.

For new projects (greenfield), reliability data from identical or similar equipment shall be used as a basis for reliability modeling. The other information required for RAM analysis may consist of PFDs, P&IDs if available, and equipment lists.

NOTE Data collected from physics of failure and remaining life analysis may also be used to supplement field repair and failure data. Professional judgment should also be used to apply data that is similar but not identical to equipment being modeled.

A.2.4.9.9 Data should be validated by operations, maintenance, and reliability personnel or others knowledgeable with the system to be modeled in an interactive session. This can be accomplished by comparing the data to be used with current knowledge of the system to be modeled and specifically with asset utilization logs. If engineering upgrades have been made to improve past problems, then the historical data should be truncated to begin at the time of the improvement. Likewise, if equipment has become recently unreliable, then the data should reflect the actual conditions.

The initial model outputs are a good place to concentrate efforts on data validation. The components that are at the top of the “worst actors” list (system criticalities or sensitivities) should be given close attention. If there are no good methods of validating the data that are high on the culpability list, then data uncertainty techniques should be used. One can utilize a distribution on any of the data distribution parameters to give an automatic sensitivity or one can simply do multiple RAM analyses with a spread of different data distribution parameters.

A.2.4.10 Fault Tree Analysis

FTA is a method used in PHA to analyze complex system or component failures in which there are dependent failure modes or failure paths to an undesired event or hazard condition. Unlike other risk and failure analysis methods, including HAZOP and FMEA, the complex interdependencies in failure modes and causes can be combined and assessed. The method may be applied to machinery to perform failure analysis on machinery components, control systems, and controls logic, for example.

The FTA is a deductive, top-down process that analyzes the possible causes and combination of causes in Boolean logic that contribute to the top level hazard or undesirable event. Application guidance is provided in IEC 61025 [24]. Typically, a Boolean logic gate diagram (refer to Figure A.6) is prepared to show the top level hazard and the multiple combinations of failure causes and events that can lead to the hazard. The probability of each failure cause/event can be quantified at each level to provide the overall likelihood of failure and each contributing failure cause.

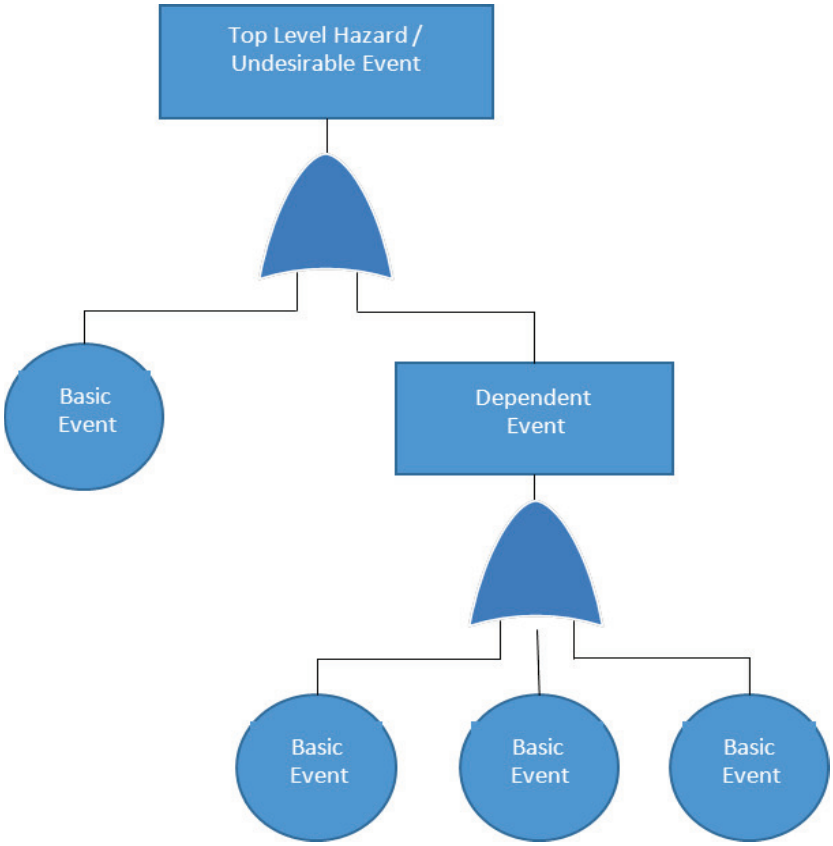


Figure A.6—Typical Fault Tree Diagram

FTA can provide the following benefits to risk assessment in machinery:

a) an understanding of the path that can lead to the hazard/undesirable event,

b) overview of the complexity of the risk,

c) ability to prioritize focus on risk mitigating measures,

d) a basis to audit the safety and reliability performance of a system or component,

e) demonstrate compliance with design intent.

A.2.5 Machinery Risk Ranking

The process step of ranking the analyzed risks is important to the overall process. It provides a mechanism to prioritize risk mitigation review and actions based upon the level of risk to the machinery owner.

The level of risk to the owner is a key element and should be defined by the machinery owner. This is typically High, Medium, and Low risks or in some cases Intolerable, Tolerable, or Acceptable risks depending on the owners' criteria and corporate risk management definitions.

The result of machinery risk analysis is a quantitative or qualitative schedule of risks that may be shown on a risk matrix or calculated using RPNs. The risk matrix communicates those risks that are classified as High, Medium, and Low. The RPN method is based on the risk levels defined as ranges in RPN values for each level of risk.

The ranking and prioritization of these risks are then identified on the level of risk defined by the owner for risk mitigation treatment.

A.2.6 Machinery Risk Mitigation

The risk mitigation measures following the risk assessment are described in the main sections of this document for each of the machinery life cycle stages.

This is an iterative process to determine if risk mitigating steps applied reduce residual risk to an acceptable level defined by the machinery owner.

A.3 Risk Assessment over Machinery Life Cycle

Risk assessment methods are a requirement for API 691 Machinery at each stage of the life cycle of the equipment. The level of appreciation and definition of machinery risks increases from the early feasibility and concept stage through to operation and maintenance of the equipment. Risk methodology and techniques alter to meet the assessment needs at each stage. This is summarized in Table A.3, which defines the risk assessment requirements, the recommended risk method, and the corresponding international practices and standards for each risk method.

Table A.3—Risk Methodologies by Machinery Life Cycle

Key Machinery Risk Management Action	Risk Method Approach	API 691 Section	Reference Standards
Feasibility and Concept Selection			
— Determine machinery TRC	— TRC assessment	4.2	API 691, A.2.4.6 above which modified API 17N [10]
— Determine readiness of machinery or machinery component(s) to qualify new technology products for service	— TRL assessment based on attributes selection Table 1	4.3.1	API 17N [10]
— Perform analytical validation of components	— POF and COF risk estimation method	4.4.10	
Front-end Engineering Design			
— Identify API 691 high-risk machinery (screening at equipment/failure mode level)	— PHA or HAZOP analysis (as part of PSM) — Based on highest COF	5.2.2	OSHA 1910.119, ISO 17776 [21], IEC 61882
— Preliminary machinery risk assessment	— Based on POF and COF analysis with risk matrix or RPN or other method	5.2.3	
— Long lead equipment	— Applicable risk assessment methods	5.6	API 691, Section 6 (Detailed Design)
— Identify and analyze risks to process availability and reliability, capital spares exposure, process technology	— RAM-1 analysis	5.3.2	ISO 60300-1 [22], ISO 61078 [23]

Key Machinery Risk Management Action	Risk Method Approach	API 691 Section	Reference Standards
Detailed Design			
— Identify API 691 high-risk machinery (screening at maintainable components/failure mechanism level)	— Based on POF and COF analysis with risk matrix or RPN or other method	6.2, Annex A	OSHA 1910.119, ISO 17776, IEC 61882
— Detailed machinery risk assessment (as specified by operator)	— If specified, perform PFMEA	6.2.4, Annex I	IEC 60812 [6]
	— If specified, LOPA	6.2.4	IEC 61511
	— If specified, FTA	6.2.4	IEC 61025 [24]
— Identify machinery failure modes that are related to a loss of containment and/or a loss of functionality that could lead to a potential process safety event	— DFMEA	6.3.2, Annex I	IEC 60812 [6]
— Identify machinery components and subcomponents having a TRL< 6 whose failure may lead to loss of containment and/or a loss of functionality that could lead to a potential process safety event	— DFMEA	6.3.2, Annex I	IEC 60812 [6]
— Identify and analyze risks to process availability and reliability, capital spares exposure, process technology	— RAM-2 analysis	6.5	ISO 60300-1, ISO 61078
Operations and Maintenance			
— Identify API 691 high-risk machinery (screening at equipment level/failure mode level)	— PHA or HAZOP analysis (as part of PSM) — Based on highest COF	8.1.2	OSHA 1910.119, ISO 17776, IEC 61882
— Field risk assessment (as specified by operator)	— If specified, perform PFMEA	8.2.2, Annex I	IEC 60812 [6]
	— If specified based on POF and COF analysis with risk matrix or RPN or other method	8.2.2	API 580 [25] (overview of general principals)
	— If specified, FTA	8.2.2	IEC 61025 [24]

Annex B
(informative)

Risk-based Machinery Validation Checklists

B.1 Introduction

This annex covers the minimum recommended validation checks to be carried out for API 691 Machinery throughout its life cycle.

a) Feasibility and concept design:

    1) design validation reviews.

b) FEED:

    1) P&ID validation reviews.

c) Detailed design:

    1) equipment service condition checklist validation reviews.

d) Operations and maintenance:

    1) pre-TA risk validation checklist reviews,

    2) major overhaul risk validation checklist reviews,

    3) additional pressure boundary inspections for machinery in corrosive, erosive, and harsh service.

B.2 Feasibility and Concept Design and FEED Validations

B.2.1 General

This section provides guidance on the design validation of machinery classified as API 691 Machinery during the feasibility and concept design and FEED phases of a project. The validation process should demonstrate that the machinery is capable of operating safely and reliably within the expected operating envelope.

B.2.2 Aerodynamic/Hydrodynamic Performance Attributes

Where applicable, the following aerodynamic/hydrodynamic performance attributes should be validated:

a) flow rate,

b) head,

c) efficiency,

d) net positive suction head required (NPSHR) (if applicable),

e) turndown performance,

f) preferred operating range,

g) allowable operating range,

h) best efficiency point.

B.2.3 Casing Design Attributes

Where applicable, the following casing design attributes should be validated:

a) pressure casing— include sealing and bolting arrangements,

b) attachments—instruments, inlet taps, outlet taps,

c) seal housing,

d) bearing housing,

e) end caps (if applicable).

B.2.4 Material Design Attributes

Where applicable, the following material design attributes should be validated:

a) necessary corrosion resistance,

b) necessary material strength,

c) wet material selections,

d) dry material selections,

e) nonmetallic material selections,

f) material compatibility with the process stream,

g) erosion resistance where process stream contains high levels of particulates,

h) mill test report.

B.2.5 Seal Design Attributes

Where applicable, the following seal design attributes should be validated:

a) sealing configuration,

b) seal type,

c) seal support plan (if applicable),

d) flush plan (if applicable),

e) seal quench plan (if applicable),

f) seal drain plan (if applicable),

g) seal face materials,

h) phase mapping (if applicable),

i) seal support system monitoring and protection instrumentation,

j) barrier and buffer fluids,

k) seal system fluid compatibility with process stream,

l) elastomer,

m) elastomer compatibility with seal system and process system constituents,

n) maximum seal temperature/pressure.

B.2.6 Rotor Dynamics Attributes

Where applicable, the following rotor dynamics attributes should be validated:

a) lateral critical speed study,

b) torsional analysis, where required,

c) separation margins,

d) amplification factors (resonances),

e) stability analysis,

f) steady state analysis,

g) transient analysis,

h) test vibration levels (if available),

i) surge (if applicable),

j) natural frequency of the rotor.

B.2.7 Impeller/Blade Design Attributes

Where applicable, the following impeller/blade design aspects should be validated:

a) stresses,

b) Security Achieved through Functional and Environmental Design (SAFE) diagram, Modified Goodman diagrams, Campbell Goodman diagrams, etc.

c) interference fits.

B.3 P&ID Reviews During FEED

B.3.1 General

This section provides guidance on the recommended minimum level of validation of pipework and instrumentation systems supporting machinery classified as API 691 Machinery during the FEED phase of a project. The validation process should demonstrate that the systems outlined in the P&IDs are capable of providing safely and reliable operation within the expected operating envelope of the machinery. The validation of P&IDs can extend into the detailed design phase of the project.

B.3.2 API 610—Centrifugal Pumps

Where applicable, the following items on P&IDs should be validated:

a) pressure taps up and downstream of the suction strainers,

b) minimum flow bypass where required depending on pump size, process and flow variability, etc.,

c) warm-up bypass line where required for hot service pumps,

d) instrumentation, alarms, and shutdowns provided in accordance with API 541, API 546, API 547, API 612, API 613, API 614, API 617, API 682, API 670, and API 677 where applicable and as noted on the equipment datasheets,

e) seal piping in accordance with the API 682 equipment datasheet,

f) lube oil mist or oil purge piping connections and piping as indicated on the API 610 equipment datasheet.

B.3.3 API 611—General-purpose Steam Turbines

Where applicable, the following items on P&IDs should be validated:

a) warm-up vent on the inlet line,

b) warm-up bypass around the inlet block valve,

c) bypass around the exhaust valve for warm-up,

d) steam trap and bypass upstream of the trip and throttle valve,

e) steam trap and bypass on the steam chest of single valve turbines,

f) steam trap and bypass on the low point of the exhaust casing,

g) low-pressure seal vent line on both seals,

h) overspeed trip protection,

i) exhaust line safety valve between the turbine and the exhaust block valve,

j) safety valve sizing,

k) safety valve setting at or below the maximum design exhaust system pressure,

l) turbine washing system (if required),

m) instrumentation, alarms, and shutdowns provided in accordance with API 611, API 614, API 670, and API 677 where applicable and as noted on the equipment datasheets,

n) shaft sealing and leak off system for condensing steam,

o) turbine drain connection,

p) insulation.

B.3.4 API 612—Special-purpose Steam Turbine

Where applicable, the following items on P&IDs should be validated:

a) warm-up vent on the inlet line,

b) warm-up bypass around the inlet block valve,

c) bypass around the exhaust valve for warm-up,

d) trap and bypass upstream of the trip and throttle valve,

e) trap and bypass on the steam chest of single valve turbines,

f) trap and bypass on the low point of the exhaust casing,

g) trap and bypass on the low point of the exhaust casing,

h) gland seal condenser system,

i) atmospheric exhaust seal,

j) trip and throttle valves,

k) full flow exhaust relief valve,

l) low-pressure seal vent line on both seals,

m) overspeed trip protection,

n) exhaust line safety valve between the turbine and the exhaust block valve,

o) safety valve sizing,

p) safety valve setting at or below the maximum design exhaust system pressure,

q) steam turbine governor/speed control,

r) last blade row protection,

s) ventilation protection system,

t) turbine washing (if required),

u) instrumentation, alarms, and shutdowns provided in API 612, API 613, API 614, and API 670 where applicable and as noted on the equipment datasheets,

v) insulation.

B.3.5 API 616—Gas Turbines

Where applicable, the following items on P&IDs should be validated:

a) instrumentation, alarms, and shutdowns provided in API 613, API 614, API 616, and API 670 where applicable and as noted on the equipment datasheets,

b) governor system,

c) flameout protection,

d) venting, purging provision,

e) fire and gas protection,

f) inlet and exhaust systems,

g) fuel valve,

h) fuel system venting,

i) overspeed trip protection controls,

j) turbine wash connections and piping,

k) lubricating oil system.

B.3.6 API 617—Axial and Centrifugal Compressors

Where applicable, the following items on P&IDs should be validated.

a) Knockout drums exist on the suction and any cooled interstages (if required).

b) Surge protection system (if applicable).

c) Recycle lines reenter upstream of the knockout drums.

d) Knockout drums are equipped with a level gauge with alarms and shutdowns.

e) Instrumentation, alarms, and shutdowns provided in accordance with API 541, API 546, API 547, API 612, API 613, API 614, API 617, API 692, and API 670 where applicable and as noted on the equipment datasheets.

f) Anti-surge recycle line tie-in points are located as close to the compressor discharge as possible.

g) Minimize the piping volume of the surge protection recycle loop to improve anti-surge protection response.

h) Check valve in the discharge downstream of the anti-surge recycle line as close as possible to the compressor discharge nozzle.

i) Flow meter on each feed and discharge stream from the unit.

j) Pressure taps upstream and downstream of the temporary strainers.

k) Instruments are changeable on the run.

l) All lines to remote pressure gauges are isolatable with double block and bleed valve arrangements at the tie-in to the main line.

m) Metering elements are outside the recycle loop for flow controlled units.

n) Safety valve on the discharge of the machine if the downstream equipment cannot stand the unit's discharge pressure under the combined conditions of trip speed, high molecular weight, high suction pressure, and low temperature.

o) If process gas is used for the gas supply to gas seals, the gas composition needs to be assessed according to the guidelines in API 692 for condensation potential in the supply lines. This will drive the requirements for a gas conditioning skid and/or supply line trace heating with lagging.

p) Dry gas seal system.

q) Surge control.

r) Continuous slope back to the tapping point on instrument tubing for surge control system.

s) Sensing elements for surge control system are located inside the recycle loop.

t) Anti-surge valves are typically designed for more than 100 % compressor flow. The silencer downstream of the recycle valve needs to be designed for increased flow. Maximum flow that this silencer sees is the maximum flow of the fully open recycle valve at the maximum pressure drop across this valve. This high flow will be seen for few seconds only once the valve suddenly opens; however, ignoring this may lead to mechanical damage of the equipment.

u) Capacity control.

v) Starting scheme for starting from settle out pressure.

w) Include scheme for positive gas seal supply pressure availability anytime case is pressurized.

B.3.7 API 618—Reciprocating Compressors

Where applicable, the following items on P&IDs should be validated:

a) knockout drums on all suction and interstages,

b) recycle lines reenter upstream of the knockout drums,

c) knockout drums are equipped with a level gauge with alarms and shutdowns,

d) automatic drains and bypasses on knockout drums to facilitate inspection,

e) suction lines between the knockout drums and the unit's flanges, including the pulsation bottles, are heat traced,

f) safety valve on each compression stage,

g) pressure and thermal relief valves on the coolant header,

h) instrumentation, alarms, and shutdowns provided in accordance with API 541, API 546, API 547, API 612, API 613, API 618, and API 670 where applicable,

i) automatic unloading capabilities in accordance with the process control philosophy,

j) double block valves and a vent to facilitate valve repairs,

k) pressure taps up and downstream of the temporary strainers,

l) provisions for back flushing the oil coolers on the water side,

m) instruments are changeable on the run,

n) all lines to remote pressure gauges are valved at the tie-in to the main line,

o) individual packing vents and distance piece drains,

p) packing vents are discharging to a safe location,

q) isolatable closed circuit so that pre-start-up run in can be performed,

r) cylinder pressure taps,

s) valve temperature indicators.

B.3.8 API 619—Screw Compressors

Where applicable, the following items on P&IDs should be validated:

a) knockout drums exist on the suction and any cooled interstages,

b) recycle lines reenter upstream of the knockout drums,

c) knockout drums are equipped with a level gauge with alarms and shutdowns,

d) instrumentation, alarms and shutdowns provided in accordance with API 541, API 546, API 547, API 612, API 613, API 614, API 619, API 692, and API 670 where applicable and as noted on the equipment datasheets,

e) check valve in the discharge line as close as possible to the compressor discharge nozzle,

f) flow meter on each feed and discharge stream from the unit, where applicable,

g) pressure taps up and downstream of the temporary strainers,

h) instruments are changeable on the run,

i) all lines to remote pressure gauges are valved at the tie-in to the main line,

j) isolatable closed circuit so that pre-start-up run in can be performed,

k) suction flare is available to dump the suction gas in the event of a shutdown,

l) metering elements are outside the recycle loop for flow controlled units,

m) safety valve on the discharge of the machine if the downstream equipment cannot stand the unit's discharge pressure under the combined conditions of trip speed, high molecular weight, high suction pressure, and low temperature,

n) phase mapping of the dry gas seal in to determine if seal gas conditioning skids are required in accordance with API 692, where applicable,

o) slide valve control, where applicable.

B.4 Vendor Qualification During FEED and Detailed Design

B.4.1 General

This section provides guidance on the qualification of a vendor to manufacture machinery classified as API 691 Machinery. The qualification process should demonstrate that the vendor has manufactured machinery of an identical type that has successfully operated under equivalent operating conditions. The critical areas relative to equivalent service conditions that should be demonstrated are included below.

B.4.2 API 610—Centrifugal Pumps

Where applicable, the following critical items relative to equipment service conditions should be validated:

a) suction pressure,

b) discharge pressure,

c) differential pressure,

d) flow,

e) specific gravity,

f) viscosity,

g) pumped product constituents (particulates, gas entrainment, etc.),

h) temperature,

i) NPSH margin,

j) specific speed,

k) suction specific speed,

l) design flow/BEP flow.

B.4.3 API 611—General-purpose Steam Turbine and API 612—Special-purpose Steam Turbine

Where applicable, the following critical items relative to equipment service conditions should be validated:

a) inlet pressure,

b) exhaust pressure,

c) inlet temperature,

d) exhaust temperature,

e) mass flow rate,

f) steam quality,

g) blade design,

h) blade passing frequency,

i) tip speed,

j) number of stages,

k) seal design,

l) bearing design and loading,

m) bearing lubrication,

n) casings design,

o) shaft design,

p) governor type,

q) overspeed trip device,

r) ventilation protection,

s) last blade protection.

For the last two stages of the blading of API 612 condensing turbines, experience should be documented in a table listing the following details:

a) tip speed,

b) blade height,

c) blade root diameter,

d) Goodman factor,

e) number of blades.

B.4.4 API 613—Special-purpose Gears

Where applicable, the following critical items relative to equipment service conditions should be validated:

a) power rating,

b) pinion speed,

c) pitch line velocity,

d) journal velocity,

e) service factors for durability and strength,

f) gear load and direction,

g) bearing load and load direction,

h) number of teeth on each rotor.

Where special-purpose gear units are installed on machinery packages, the vendor should have manufactured at the proposed manufacturing location, at least two equivalent gear units.

B.4.5 API 616—Gas Turbines

Where applicable, the following critical items relative to equipment service conditions should be validated:

a) inlet air system,

b) exhaust system,

c) starting system,

d) site rated firing temperature,

e) inlet air filtration system,

f) emissions,

g) acceptable Wobbe index range,

h) base/peak loads,

i) fuel system,

j) lubrication system,

k) post FAT borescope inspection prior to shipping.

For API 616 gas turbine packages, the vendor should have manufactured an identical gas turbine (model number) of comparable design context, speed, power rating, etc. to that of the intended duty. The vendor should demonstrate their experience on an individual component and service condition basis, as listed below. Experience need not be concentrated in a single reference, but may be spread through several operating referenced designs.

NOTE The Wobbe index range is a gauge of the OEM allowable range of change in heating value of fuel gas. It is the ratio of the lower heating value (LHV) of the fuel gas divided by the square root of the specific gravity (SG) of the fuel gas:

$$\text{Wobbe index} = \text{LHV} / \sqrt{\text{SG}}$$

The “modified” Wobbe index range can also be used, which takes into account absolute fuel temperature (TFA):

$$\text{modified Wobbe index} = \text{LHV} / \sqrt{\text{SG} \times \text{TFA}}$$

B.4.6 API 617—Axial and Centrifugal Compressors and Expander Compressors

Where applicable, the following critical items relative to equipment service conditions should be validated:

a) suction pressure,

b) discharge pressure,

c) settle out pressure,

d) suction temperature,

e) discharge temperature,

f) molecular weight,

g) head,

h) impeller tip speed,

i) shaft speed,

j) number of stages,

k) API 692 seal configuration,

l) volumetric capacity,

m) power rating,

n) inlet Mach number.

The critical areas relative to component design that should be demonstrated include the following:

a) API 692 dry gas seals and sealing system, which should be of a comparable design and configuration, diameter, peripheral speed, power rating, and differential pressure for a gas of comparable characteristics to that of the intended duty,

b) bearing design and loading,

c) number of stages and staging arrangement,

d) casing size, design, and pressure rating.

Experience need not be concentrated in a single reference, but may be spread through several operating referenced designs.

B.4.7 API 618—Reciprocating Compressors and API 619—Rotary-type Positive Displacement Compressors

For API 618 and API 619 compressor packages, the vendor should have manufactured a reciprocating compressor of comparable design and configuration, speed, power rating, and discharge pressure for a fluid of comparable specific gravity to that of the intended duty. The vendor should demonstrate their experience on an individual component and service condition basis, as listed below. Experience need not be concentrated in a single reference, but may be spread through several operating referenced designs.

Where applicable, the following critical items relative to equipment service conditions should be validated:

a) pressure,

b) relative molecular mass,

c) volumetric capacity,

d) power rating,

e) speed,

f) temperature,

g) process gas composition.

The critical items relative to API 618 mechanical design that should be demonstrated are:

a) packing system,

b) bearing design and loading,

c) cylinder design and cylinders arrangement,

d) frame size and design,

e) material,

f) valve and unloader design,

g) pistons, piston rods, and piston rings,

h) crankshaft,

i) power transmission components,

j) lubrication system—frame, cylinder, and packing.

Experience need not be concentrated in a single reference, but may be spread through several operating referenced designs.

B.5 Operations and Maintenance Machinery Checklists

B.5.1 Pre-turnaround Checklists

B.5.1.1 General

Machinery classified as API 691 Machinery should be evaluated for inclusion in any planned shutdown activities. Risk is dynamic and changes during operation. As a general rule, machinery that frequently operates outside IOWs should be considered for special attention and activities during shutdown activities. Operator risk tolerance and the checklists outlined below have been provided to assist with the inclusion decision. These lists are not comprehensive in terms of machinery types or specific checks.

B.5.1.2 API 610—Centrifugal Pumps

This list is provided to assist with the TA scope inclusion decision for API 610 pumps classified as API 691 Machinery.

a) Check equipment condition history.

b) Check pump performance against published curves.

c) Check vibration and bearing housing temperatures.

d) Check sump drain site-glasses for abnormalities in the oil (water, sediment, metals).

e) Survey seal support systems (monitor seal flush temperatures, pressures, pot levels, etc.).

f) Inspect the coupling with a strobe light, if possible.

g) Review the last inspection and repair reports.

h) Any known issues that arose since the last inspection/repair (including process upsets) or issues that were not addressed during the last inspection/repair [Item g)].

i) Any concerns with extending pump operation in another TA cycle?

j) Case pressure boundary integrity assurance—internal inspection, hydrotest (primarily applicable to corrosive, erosive, service).

B.5.1.3 API 611—General-purpose Steam Turbine and API 612—Special-purpose Steam Turbine

This list is provided to assist with the TA scope inclusion decision for API 611 general-purpose steam turbines and API 612 special-purpose steam turbines classified as API 691 Machinery.

a) Check equipment condition history.

b) Check performance including first stage nozzle pressure, delta pressure across trip valve, extraction pressure, exhaust pressure, vacuum, and hot well temperature and compare to normal conditions.

c) Check vibration and bearing temperatures (housing, oil return, bearing metal).

d) Check sump drain site-glasses for abnormalities in the oil (water, sediment, metals) and condition of lube and control oil using oil analysis.

e) Check for excessive packing leaks, excessive water in oil, and gland sealing system abnormalities (vacuum pump, surface condenser level, exchangers, eductor, etc.).

f) Check operation of the governor's response to signal changes and load changes, including a check for excessive slop in linkages and bushings.

g) Review the last inspection and repair reports.

h) Any known issues that arose since the last inspection/repair (including process upsets) or issues that were not addressed during the last inspection/repair [Item g)].

i) Confirm that required shutdown trip testing is included in the TA plan.

j) Any concerns with extending steam turbine operation to another TA cycle?

B.5.1.4 API 616—Gas Turbines

This list is provided to assist with the TA scope inclusion decision for API 616 gas turbines classified as API 691 Machinery. Gas turbines have life-limited combustion and hot gas path components that require time-based inspections, which are usually determined from historical findings in past inspections, metallurgy of components, fired hours of service, fuel quality and type, operational mode, environmental conditions, and firing temperatures. OEM recommendations and/or past inspection history are used to set frequencies of combustion inspections, hot gas path inspections, overhauls, and rotor breakdown inspections.

a) Check equipment condition history.

b) Check performance of axial compressor and turbine sections, including a comparison of inlet and outlet temperatures and pressures to normal conditions.

c) Check guide vanes for excessive looseness in linkages and for proper operation.

d) Check operation of inlet gas and gas ratio valves and responses to signal changes and load changes.

e) Review the last inspection and repair reports.

f) Any known issues that arose since the last inspection/repair or issues that were not addressed during the last inspection/repair [Item e)].

g) Any concerns with extending gas turbine operation to another TA cycle, taking into consideration the special note above.

B.5.1.5 API 618—Reciprocating Compressors

This list is provided to assist with the TA scope inclusion decision for API 618 reciprocating compressors classified as API 691 Machinery.

a) Check equipment condition history.

b) Check performance of each compression stage (pressures, temperatures, etc.) and compare to normal conditions.

c) Check vibration and rod drop systems for abnormalities.

d) Check valve cover temperatures, packing temperatures, and packing and distance piece vents and drains for abnormalities.

e) Verify that unloader actuators are functioning properly and that positions match the loading steps.

f) Check that the cylinder lubrication system is functioning properly.

g) Check for excessive wear metals in crankcase oil.

h) Review the last inspection and repair reports.

i) Any known issues that arose since last inspection/repair (including process upsets) or issues that were not addressed during the last inspection/repair [Item h)].

j) Survey foundation, grouting, anchoring and support system for abnormal cracks, loose joints, broken fasteners, etc.

k) Survey frame, frame extensions, distance pieces, cylinders, heads, and valve covers for loose or broken fasteners.

l) Check for hot pressure-relief valves on interstage and discharge lines.

m) Check that ancillary support systems are functioning normally.

n) Any concerns with extending reciprocating compressor operation to another TA cycle?

B.5.1.6 API 617—Centrifugal Compressors and API 619—Screw Compressors

This list is provided to assist with the TA scope inclusion decision for API 617 centrifugal compressors or API 619 screw compressors classified as API 691 Machinery.

a) Check equipment condition history.

b) Check performance against published curves.

c) Check vibration and bearing temperatures.

d) Check sump drain site-glasses for abnormalities in the oil (water, sediment, metals).

e) Survey seal support systems (monitor seal temperatures, pressures, pot levels, filter DP, etc.).

f) Review the last inspection and repair reports.

g) Any known issues that arose since the last inspection/repair (including process upsets) or issues that were not addressed during the last inspection/repair [Item f)].

h) Any concerns with extending compressor operation another TA cycle?

B.5.2 Machinery Overhauls

B.5.2.1 General

The scope of both minor and major overhauls are typically defined by the severity of failure events, degree of observed performance deficiencies, or the results of asset specific health checks routinely performed on high-risk machinery. To the extent possible, operating companies will typically schedule overhauls to coincide with scheduled turnarounds with greater preference given to those scope activities that result in the greatest risk mitigation. The success of overhauls following unplanned (forced) outages is often dependent on prior

field risk assessments that have considered the availability of skilled personnel, preapproved repair procedures, and spare parts. Depending on the extent of the overhaul, close coordination may be required with vendors to ensure safe and reliable operation following critical repairs and/or inspections. Unless otherwise specified, operating companies should follow the vendor's repair or replacement, procedures, practices, and recommendations for any components or subcomponents that mitigate the risks of failure. However, as a minimum, the following additional checks, inspections, and maintenance tasks should be considered within the overhaul scope using approved SOPs.

NOTE The checks listed are not comprehensive and do not constitute complete overhaul scope for listed machinery types.

B.5.2.2 API 610—Centrifugal Pumps

The following list is provided to assist with compiling the overhaul scope tasks for API 610 pumps classified as API 691 Machinery.

a) Check alignment.

b) Inspect seal gland connections.

c) Check for surface or subsurface cracks on the shaft, impeller vanes, and wear rings.

d) Check for damage to threads.

e) Check for fretting at any shaft diameter.

f) Check for damage to keyways.

g) Check for shaft discoloration.

h) Check for excessive wear that may have been caused by hydraulic instability, cavitation, or suction recirculation.

i) Inspect and test all check valves.

j) Check condition of bearings.

k) Inspect case and flange for damage.

l) Inspect for erosion and corrosion.

m) Check balance line wall thickness.

n) Check drain and case thickness.

o) Check seal pressures.

p) Check wall thickness for cryogenic services.

B.5.2.3 API 611—General-purpose Steam Turbine and API 612—Special-purpose Steam Turbine

The following list is provided to assist with compiling the overhaul scope tasks for API 611 general-purpose steam turbines and API 612 special-purpose steam turbines classified as API 691 Machinery.

a) Inspect case, flange, and drain lines.

b) Check wall thicknesses.

c) Nondestructive testing (NDT) blades and disks.

d) Check alignment.

e) Clean/test lube oil coolers.

f) Survey pipe supports/hangers, expansion joints once every 2 years.

g) Clean instrument taps.

h) Check integrity of trip or trip throttle valve.

i) Check steam admission valve tightness, calibration with control system, travel, freedom of movement, etc.

j) Inspect steam strainer.

k) Check gland eductors.

l) Inspect coupling.

m) Clean and test gland seal cooler.

n) Review turbine operating records since the last inspection.

o) Check junction boxes for oil or water contamination.

p) Observe the condition of the foundation.

q) Check the tension on the foundation bolts and for soft foot.

r) Conduct an overspeed trip test.

s) Inspect bearings, oil drains.

t) Calibrate vibration monitoring system.

u) Inspect casing internally (borescope, or alternate).

B.5.2.4 API 616—Gas Turbines

The following list is provided to assist with compiling the overhaul scope tasks for API 616 gas turbines classified as API 691 Machinery.

a) Perform cold side and hot gas path inspections as required.

b) Check alignment.

c) Survey pipe supports/hangers, expansion joints.

d) Clean instrument taps.

e) Inspect, calibrate surge protection system.

f) Inspect, calibrate vibration monitoring system.

g) Check integrity of trip system.

h) Inspect, calibrate inlet gas and gas ratio, IGVs, discharge control valve, vent control valve, capacity/pressure control system.

i) Inspect coupling(s).

j) Borescope inspection of flame tubes and transition ducts.

k) Visually inspect valve seats.

l) Visual inspection, gear tooth check, and check/clean of lubrication spray nozzle.

m) Thoroughly examine system protective devices.

n) Calibrate fire extinguishing system.

o) Weigh fire suppression cylinders.

p) Check condition of bearings.

q) Check oil and other fluid systems for leaks.

r) Check cleanliness of filters and coolers.

B.5.2.5 API 617—Axial and Centrifugal Compressors and Expander Compressors

The following list is provided to assist with compiling the overhaul scope tasks for API 617 axial and centrifugal compressors and expander compressors classified as API 691 Machinery.

a) Inspect case and flanges for damage.

b) Inspect for erosion and corrosion.

c) Check balance line wall thickness.

d) Check drain and case thickness.

e) Check wall thickness for cryogenic services.

f) Check seal pressures.

g) Check alignment.

h) Clean suction screens.

i) Inspect/test discharge check valve.

j) Clean/test lube and seal oil coolers.

k) Survey pipe supports/hangers, expansion joints.

l) Clean instrument taps.

m) Inspect, calibrate surge protection system.

n) Inspect, calibrate vibration and axial displacement monitoring system.

o) Inspect, calibrate vibration monitoring system.

p) Inspect, calibrate inlet control valve, IGVs, discharge control valve, vent control valve, capacity/pressure control system.

q) Inspect coupling(s).

r) Inspect, clean, test compressor interstage and discharge coolers.

s) Inspect bearings, oil drains.

t) Inspect casing internally (borescope, or alternate).

B.5.2.6 API 618—Reciprocating Compressors

The following list is provided to assist with compiling the overhaul scope tasks for API 618 reciprocating compressors classified as API 691 Machinery.

a) Inspect case and flanges for damage.

b) Inspect for erosion and corrosion.

c) Check cylinder and drain wall thickness.

d) Check alignment.

e) Check frame and foundation:

   1) visual inspection of foundation for cracks,

   2) anchor bolt pulldown checks,

   3) frame level checks,

   4) crosshead guide level checks,

   5) main bearing clearance checks,

   6) crankshaft thrust bearing checks,

   7) crankshaft web deflection checks,

   8) connecting rod bearing clearance checks,

   9) connecting rod thrust clearance checks,

   10) frame lubrication checks.

f) Check electric drive motor:

   1) engine type synchronous motor checks,

   2) two bearing induction motor checks.

g) Check crosshead guide and crossheads:

   1) crosshead guide checks,

   2) crosshead checks,

3) crosshead pin bushing clearance checks,

4) oil scraper checks.

h) Check compressor cylinder and distance pieces:

1) compressor cylinder/liner bore checks,

2) cylinder level checks,

3) cylinder to crosshead guide bolting checks,

4) cylinder lube lines checks.

i) Check piston rod and assembly:

1) piston rod checks,

2) piston checks,

3) piston ring checks,

4) piston end clearance checks,

5) piston rod run out checks.

j) Check piston rod cylinder and intermediate pressure packing.

k) Inspect valve, unloader, and clearance pocket bolts.

l) Inspect (NDT) suction and discharge pulsation bottles and associated connections.

B.5.2.7 API 619—Screw Compressors

The following list is provided to assist with compiling the overhaul scope tasks for API 619 screw compressors classified as API 691 Machinery.

a) Inspect case and flanges for damage.

b) Inspect for erosion and corrosion.

c) Check cylinder and drain wall thickness.

d) Check alignment.

e) Clean suction screens.

f) Inspect/test check valve.

g) Clean/test lube and seal oil coolers.

h) Survey pipe supports/hangers.

i) Clean instrument taps twice per year or more frequently.

j) Replace inlet filter elements, inspect filter housing.

k) Inspect, calibrate vibration monitoring system.

l) Inspect, calibrate inlet control valve, capacity/pressure control system, slide valve system.

m) Inspect coupling(s).

n) Inspect, clean test compressor interstage and discharge coolers.

B.5.3 Additional Pressure Boundary Inspections for Machinery in Corrosive, Erosive, and Harsh Service

Based on machinery condition and other factors, more detailed inspections and CM activities should be considered as well as adjustments to maintenance tasks and frequencies for equipment in corrosive, erosive, and harsh service.

The operator should consider performing the following inspections (may be tied to site TA schedule).

a) NDT of any welded connections for nozzles.

b) Visual inspection of sealing surface areas to identify any pitting or mechanical damage.

c) Internal dimension measurements to identify material loss through corrosion, erosion, or wear. Thickness readings may be taken using UT in cases where component geometry prevents use of conventional measuring methods.

d) External examination of the casing to identify material loss through corrosion.

e) Examination of casing drain connections.

f) Baseplate integrity check.

g) Visual inspection of driven and driver mounting foot.

h) Visual inspection of the external piping including piping used for auxiliary systems in lube oil, sealing, and cooling systems.

i) Inspection of auxiliary system orifice plates as applicable.

j) Fatigue life and residual life estimation.

k) Pipe strain/pipe alignment.

l) Visual inspection for excessive pipe misalignment resulting in excessive nozzle.

m) Leak point inspections on split lines, flanges, balance lines, recycle lines, drains, etc.

Annex C
(informative)

Machinery Failure Modes, Mechanisms, and Causes

C.1 Introduction

Benchmarking efforts within the industry have ambitiously attempted to classify failures under a single set of codes intended to be applicable for all equipment types, operating conditions, and processes. More focused industry work that has identified failures applicable to a single type of equipment have proven to be of greater value in the prevention of HSE incidents throughout the industry. API 571 (*Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*), for example, has enabled operators to have greater clarity in developing inspection programs, fitness-for-service assessments, and risk-based inspection applications. Similarly, this recommended practice is intended to aid the operator in better understanding:

a) failure modes, mechanisms, and causes of machinery failures,

b) affected materials prone to some machinery mechanisms,

c) critical factors that affect certain mechanisms (i.e. rate of damage),

d) appearance or morphology of mechanisms—a description of the failure mechanism, with pictures in some cases, to assist with recognition of the condition.

The value of this annex is in assisting the operator in developing machinery specific PFMEAs (Annex A) for the purpose of preventing or mitigating risks by more effectively designing and optimally selecting maintenance tasks (Section 6) that target the most dangerous and relevant failure mechanisms associated with API 691 Machinery.

NOTE While failure modes, mechanisms, and causes are both equipment and process specific, there are, however, several areas of overlap with equipment types operating within a similar or identical process. The PFDs highlighted in API 571 show some of the areas within the unit where many of the primary failure mechanisms can be found. The reader should be advised that this is not intended to be an all-inclusive list of the failure mechanisms for a given process, but should serve as a starting point for reference and information.

While this annex is intended to cover most failure mechanisms for API specified machinery, there may be other special-purpose machinery whose failures are not adequately described. The user is encouraged to seek guidance from the OEM or independent lab to determine the root cause and in these cases should gather information specific to these unique assets. Identification of credible damage mechanisms is essential to the quality and effectiveness of risk analysis. The user should be knowledgeable about these unique assets.

C.2 Failure Observations

C.2.1 Failures can manifest themselves in a variety of ways. The way they are found can vary depending on who is working with or around the equipment. People (operators, mechanical, and electrical technicians, CM technicians, e.g. vibration and thermography) that work with and around machinery may observe failures in different ways.

C.2.2 Table C.1 summarizes common observations with machinery failure mechanisms.

Table C.1—Observations Associated with Common Machinery Failure Mechanisms

Ref.	Mechanism	Component Failure	Discoloration	External Leak	Loose Parts	Loss of Output	Noise/Sound	Output Change—Flow	Output/Input Change—Pressure	Output/Input Change—Temperature	Loss of Performance (e.g. Flow, Pressure)	Product Quality	Seized Part	Stops	Vibration	Will Not Start	Loss of Barrier Fluid (e.g. Level, Pressure)	Visual Damage/Degradation	Lubrication (Contamination)	Bearing Temperature	Borescope—Deposits	Borescope—Distortion	Borescope—Impact Damage	Borescope—Metal Loss	Oil Analysis	Sometimes Observes Movement	Thermography Hot Spot	Beach Marks	Blown Fuse	Burnt Part	Color Variations	Cracks	Distortion	External Corrosion	Fractured Part	Impeller Damage	Internal Corrosion	Loose/Broken Wire	Metal Loss—Thinning	Pitting	PM Checks	Tripped Breaker
1	Brittle fracture	X			X	X	X						X																				X							
2	Cavitation	X					X		X	X	X				X					X														X			X	X		
3	Circuit failure													X		X											X		X	X										X
4	Corrosion (uniform, pitting, oxidation, sulfidation, etc.)			X															X		X			X	X						X				X			X		
5	Deformation														X	X		X															X							
6	Electrical discharge																	X							X														X		
7	Environmental cracking— stress corrosion cracking (SCC) (e.g. ammonia, caustic, chloride, hydrogen, sulfide)	X	X	X																											X	X								
8	Erosion—(e.g. droplets, solids, corrosion)			X							X	X								X																X				
9	Fatigue, contact	X					X						X	X	X	X		X	X	X					X						X						X			
10	Fatigue (mechanical/thermal/ corrosion-fatigue)	X		X	X	X	X						X		X			X							X		X				X			X		X				

Ref.	Mechanism	Component Failure	Discoloration	External Leak	Loose Parts	Loss of Output	Noise/Sound	Output Change—Flow	Output/Input Change—Pressure	Output/Input Change—Temperature	Loss of Performance (e.g. Flow, Pressure)	Product Quality	Seized Part	Stops	Vibration	Will Not Start	Loss of Barrier Fluid (e.g. Level, Pressure)	Visual Damage/Degradation	Lubrication (Contamination)	Bearing Temperature	Borescope—Deposits	Borescope—Distortion	Borescope—Impact Damage	Borescope—Metal Loss	Oil Analysis	Sometimes Observes Movement	Thermography Hot Spot	Beach Marks	Blown Fuse	Burnt Part	Color Variations	Cracks	Distortion	External Corrosion	Fractured Part	Impeller Damage	Internal Corrosion	Loose/Broken Wire	Metal Loss—Thinning	Pitting	PM Checks	Tripped Breaker
11	Faulty or no power/voltage											X		X		X											X		X								X				X
12	Faulty or no signal/indication/alarm											X		X		X							X	X												X					
13	Foreign object damage	X					X				X			X	X			X					X	X																	
14	Fouling/contamination							X	X	X	X				X				X	X	X																				
15	Fretting/wear	X	X		X								X		X					X						X											X				
16	Seal failure	X	X	X			X					X		X			X		X																				X		
17	Selective leaching (dealloying)			X							X																											X			
18	Temper embrittlement	X				X							X																												

C.3 Failure Modes

Failure mode is the general manner by which a failure of an item and its impact on equipment/system operation becomes evident.

Failure modes should normally relate to the equipment-class level in the hierarchy. At the equipment unit level, failure modes would typically align with specific functional failures (e.g. fails while running, fails to deliver specified flow and pressure).

Failure modes may be hidden, at least until they are observed during a FF task.

According to API 689 and ISO 14224 [16], failure modes can be categorized into three types:

a) desired function is not obtained (e.g. failure to start, fails while running),

b) specified function lost or outside accepted operational limits (e.g. fails to deliver specified flow and pressure, spurious stop, high output),

c) failure indication is observed, but no immediate and critical impact on the equipment-unit function (degraded or incipient conditions),

Table C.2 summarizes common failure mode descriptions used within the industry for machinery [16].

Table C.2—Failure Mode Descriptions

Failure Mode Code	Description	Examples
AIR	abnormal instrument reading	false alarm, faulty instrument indication
BRD	breakdown	serious damage (seizure, breakage, etc.)
ERO	erratic output	oscillating, hunting, instability, etc.
ELF	external leakage of supplied fuel	external leakage of fuel, gas or diesel
ELP	external leakage of process medium	oil, gas, water, etc.
ELU	external leakage utility	lubricant, cooling water, etc.
FTS	failure to start on demand	does not start when required
HIO	high output	overspeed, flow, pressure, etc. impacting output
INL	internal leakage	leakage internally of process or utility fluids
LOO	low output	flow, pressure, etc. impacting output
NOI	noise	abnormal noise
PDE	parameter deviation	monitored parameter exceeding limits, e.g. high/low alarm
PLU	plugged/choked	flow restrictions
SER	minor in-service problem	discoloration, loose items, etc.
STD	structural deficiency	material damages
STP	failure to stop	does not stop when required
UST	spurious stop	unexpected shutdown
OTH	other	failure nodes not covered above

C.4 Failure Mechanisms

Failure mechanisms are the apparent physical, chemical, electrical, thermal, or other processes that technical deduction concludes led to the failure. They will normally be related to a lower indenture level (subunit or maintainable-item level). Table C.3 summarizes the most common failure mechanisms associated with machinery.

C.5 Failure Causes

Failure causes are the initiator of the process by which deterioration begins, ultimately resulting in failure. In other words, failure causes are what initiate the failure mechanism (from the user/owner's perspective, where the defects manifested themselves)—failure being the termination of the ability of an item to perform a required function. Examples of failure causes are:

a) design (can relate to the design of the machinery/system itself or to the initial specification of the requirements for the machinery/system),

b) manufacturing quality (e.g. variation in quality of "identical" products from same vendor, but from different manufacturing locations, or reverse engineered components from parts replicators),

c) installation,

d) maintenance (technical actions, intended to retain an item in, or restore it to, a state in which it can perform a required function),

e) use or operation (in user/owner's process or application, at specific location),

f) operating context changes (e.g. changes in the raw materials or manufacturing process that can make a good design become a bad one),

g) management (administrative actions),

h) miscellaneous (e.g. weather, natural disasters).

Failure causes will also normally be related to a lower indenture level (component/maintainable item or part level).

Table C.4 summarizes common machinery failure causes.

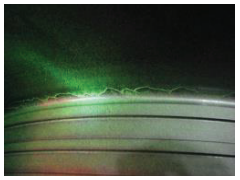
Table C.3—Machinery Failure Mechanisms

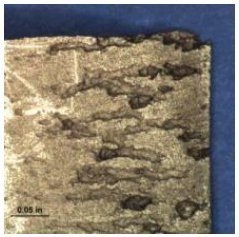
Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
1.	Brittle fracture  Brittle fracture of 2.2 in. wall C-0.5 Mo exchanger channel during hydrotest	Material	Metallurgical degradation	Loss of output, component failure, leak, noise, loose and seized parts		Fractured part	Brittle fracture is the sudden rapid fracture under stress (residual or applied) where the material exhibits little or no evidence of ductility or plastic deformation. Carbon steels and low alloy steels are of prime concern, particularly older steels. 400 series stainless steels are also susceptible. For a material containing a flaw, brittle fracture can occur. Following are important factors to consider with this failure mechanism: a) the material fracture toughness (resistance to crack like flaws) as measured in a Charpy impact test; b) the size, shape, and stress concentration effect of a flaw; c) the amount of residual and applied stresses on the flaw; d) susceptibility to brittle fracture may be increased by the presence of embrittling phases; e) steel cleanliness and grain size have a significant influence on toughness and resistance to brittle fracture; f) thicker material sections have a lower resistance to brittle fracture due to a higher constraint that increases triaxial stresses at the crack tip; g) in most cases, brittle fracture occurs only at temperatures below the Charpy impact transition temperature (or ductile-to-brittle transition temperature), the point at which the toughness of the material drops off sharply.

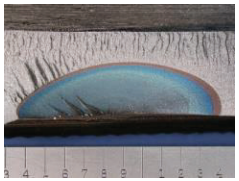
Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
2.	Cavitation  Cavitation pitting on the low-pressure side of a stainless steel pump impeller	Material	Metal loss	Performance problem, noise, vibration	Vibration, noise	Impeller damage	Cavitation is a form of erosion caused by the formation and instantaneous collapse of innumerable tiny vapor bubbles. The collapsing bubbles exert severe localized impact forces that can result in metal loss referred to as cavitation damage. The bubbles may contain the vapor phase of the liquid, air, or other gas entrained in the liquid medium. Cavitation is best prevented by avoiding conditions that allow the absolute pressure to fall below the vapor pressure of the liquid or by changing the material properties. Examples include the following. a) Streamline the flow path to reduce turbulence. b) Decrease fluid velocities. c) Remove entrained air. d) Increase the suction pressure of pumps. e) Alter the fluid properties, perhaps by adding additives. f) Use hard surfacing or hardfacing. g) Use of harder and/or more corrosion resistant alloys.
3.	Circuit failure	Electrical		Stops/alarms/trips, will not start		Blown fuse, burnt part	Open or short circuit

Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
4.	Corrosion (Uniform, pitting, oxidation, sulfidation, etc.)  Corrosion caused by poor steam chemistry (Photograph compliments of M&M Engineering Assoc.)	Material	Metal loss	Leaks, discoloration		Internal/ external corrosion, pitting	The deterioration of metal caused by chemical or electrochemical reaction of a metal with its environment, resulting in metal loss. The loss can take many forms, including general uniform metal loss, localized metal loss in the form of pitting, high temperatures causing oxidation, etc. Sulfidation occurs in piping and equipment in high temperature environments where sulfur-containing streams are processed. Common areas of concern are the crude, FCC, coker, vacuum, visbreaker, and hydroprocessing units. Corrosion in boiler feedwater and condensate return systems is usually the result of dissolved gases, oxygen, and carbon dioxide, which lead to oxygen pitting corrosion and carbonic acid corrosion, respectively. Critical factors are the concentration of dissolved gas (oxygen and/or carbon dioxide), pH, temperature, quality of the feedwater, and the specific feedwater treating system.
5.	Deformation  Tube failure by bulging and rupture due to short-term overheating	Mechanical	Distortion	Vibration	Vibration, noise	Distortion	Deformation is the bending, twisting, distorting, bowing, or warping of a metal component that prevents the proper operation of a piece of equipment.

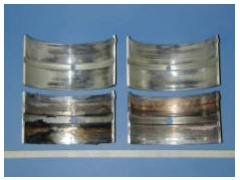
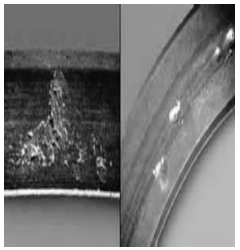
Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
6.	Electrical Discharge  Spark tracking on an outer oil seal ring  Frosted gear teeth on a speed increaser gear (Photographs compliments of Dresser Rand)	Material	Metal loss	Vibration, excessive seal oil flow	Oil analysis	Pitting	A pitting mechanism caused by passing electrical currents between two surfaces. If current is high enough, very localized melting can occur. Electrical discharge is also referred to as “frosting” or “spark tracking.” Here the names relate to the observations of the damaged parts. Common sources of electrical discharge are steam turbines, especially those with wet steam running through the latter stages, and electric motor driven trains. Degradation or lack of grounding brushes, coupling electrical insulation, motor bearing insulation, and sound overall equipment grounding are typical causes for the appearance of electrical discharge damage. Certain combinations of lube oil and oil filter materials can also create static in the lube and or seal oil. Here the damage is typically confined to the filter elements.

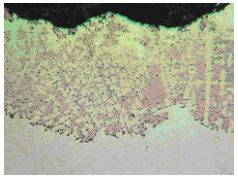
Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
7.	Environmental cracking—SCC (e.g. ammonia, caustic, chlorides, hydrogen, sulfide)  SCC of turbine disk caused by caustic carryover in steam (Photograph compliments of M&M Engineering Assoc.)	Material	Crack	Leaks, discoloration, component failure		Cracks	Environmental cracking is a common term applied to the cracking of metals under the combined action of tensile stress and a specific corrodant. For example, 300 series stainless steel is susceptible to chlorides, while copper is susceptible to ammonia. Even steels are susceptible to anhydrous ammonia. Most steels (carbon to low alloy to stainless) are susceptible to caustic. Cracking has been reported down to ambient temperatures with some amines. Increasing temperature and stress levels increases the likelihood and severity of cracking.

Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
8.	Erosion (e.g. droplets, solids, corrosion)  Trailing edge erosion caused by recirculation flow of water droplets on last stage steam turbine blades (Photograph compliments of M&M Engineering Assoc.)	Material	Metal loss	Leaks, performance problem, product quality		Metal loss—thinning, grooving	Erosion is the accelerated mechanical removal of surface material as a result of relative movement between, or impact from, solids, liquids, vapor, or any combination thereof. Corrosion can also contribute to erosion by removing protective films or scales, or by exposing the metal surface to further corrosion under the combined action of erosion and corrosion. Erosion and erosion-corrosion are characterized by a localized loss in thickness in the form of pits, grooves, gullies, waves, rounded holes, and valleys. These losses often exhibit a directional pattern. Failures can occur in a relatively short time.
9.	Fatigue, contact	Material	Crack	Vibration	Oil analysis, vibration	Cracks, metal loss	Cracking and subsequent spalling of metal subjected to alternating Hertzian (contact) stresses.

Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
10.	Fatigue (mechanical, thermal, vibration, corrosion-fatigue)  Fatigue failure of a compressor blade in a gas turbine (Photograph compliments of M&M Engineering Assoc.)	Material	Crack	Leak, component failure, vibration	Vibration	Cracks	Fatigue cracking is a mechanical form of degradation that occurs when a component is exposed to cyclical stresses for an extended period, often resulting in sudden, unexpected failure. The signature mark of a fatigue failure is a “clam shell” type fingerprint that has concentric rings called “beach marks” emanating from the crack initiation site. Thermal cycles can cause thermal stresses leading to thermal fatigue. If a corrosive atmosphere is present along with the cyclic stresses, corrosion fatigue can occur. Key factors affecting thermal fatigue are the magnitude of the temperature swing and the frequency (number of cycles). Time to failure is a function of the magnitude of the stress and the number of cycles and decreases with increasing stress and increasing cycles. Start-up and shutdown of equipment increase the susceptibility to thermal fatigue. There is no set limit on temperature swings; however, as a practical rule, cracking may be suspected if the temperature swings exceeds about 200 °F (93 °C).
11.	Faulty or no power/voltage	Electrical		Stops, will not restart		Loose/ broken wire or tripped breaker, blown fuse	The intermittent or permanent loss of electrical power—AC or DC or excessive or inadequate electrical power.
12.	Faulty or no signal/indication/ alarm	Instrument		Stops/alarms/trips product quality, cannot start		PM checks	A loss of, defective or errant signal leading to a failure.

Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
13.	Foreign object damage (FOD)  FOD damage on first stage impeller	Material	Distortion	Performance problem/vibration, sound	Borescope—see deformation, impact damage, metal loss		Damage caused by foreign objects impacting the rotating and stationary parts of rotating equipment.
14.	Fouling/ contamination  Steam turbine fouled from steam chemistry upset (Photograph compliments of M&M Engineering Assoc.)	External	Unwanted deposits/ chemicals	Performance problem/vibration, pressure, temperatures, flow	Vibration, borescope—observe deposits		The buildup of deposits or introduction of contaminants that prevent the proper function of equipment.

Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
15.	Fretting/wear  Severe bearing wear from inadequate lubrication (Photograph compliments of M&M Engineering Assoc.)	Material	Metal loss		Oil analysis, vibration, discoloration debris, sometimes movement	Metal loss	Wear that occurs between tight-fitting surfaces subjected to oscillation at very small amplitude. This type of wear can be a combination of oxidative wear and abrasive wear. Abrasive wear is the removal of material from a surface when hard particles slide or roll across the surface under pressure. The particles may be loose or may be part of another surface in contact with the surface being abraded.
16.	Seal failure  Face blistering on a mechanical seal (Photograph compliments of Maintenance World Magazine)	Material		Leaks		Leak	Degradation or cracking of a seal that allows the fluid being sealed to leak.

Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
17.	Selective leaching (dealloying)  Cross section of a silicon-brass alloy C87500 pump impeller from stagnant firewater service	Material	Metallurgical degradation	Performance problem, leak		Metal loss, color variations	Dealloying is a selective corrosion mechanism in which one or more constituents of an alloy are preferentially attacked leaving a lower density (dealloyed) often porous structure. Component failure may occur suddenly and unexpectedly because mechanical properties of the dealloyed material are significantly degraded. Factors that influence dealloying include the following. a) The composition of the alloy and exposure conditions including temperature, degree of aeration, pH, and exposure time. b) Dealloying occurs with several different alloys but is usually limited to very specific alloy-environment combinations. c) Exact conditions under which dealloying occurs are often hard to define and damage may occur progressively over many years in service.

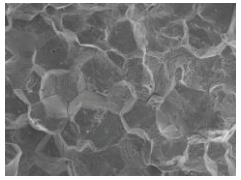
Ref.	Mechanism	Category	Degradation Type	Observations By			Definition
				Operator	CM Tech	Mechanic/ Electrician	
18.	Temper embrittlement  Sample of fractured steel that had been embrittled by improper heat treatment in the embrittling temperature range. The “rock candy” appearance of the fracture is typical of intergranular cleavage. (Photograph compliments of M&M Engineering Assoc.)	Material	Metallurgical degradation	Loss of output, component failure, seized parts		Fractured part	Temper embrittlement is the reduction in toughness due to a metallurgical change that can occur in some low alloy steels as a result of long-term exposure in the temperature range of about 650 °F to 1100 °F (343 °C to 593 °C). This change causes an upward shift in the ductile-to-brittle transition temperature as measured by Charpy impact testing. Although the loss of toughness is not evident at operating temperature, equipment that is temper embrittled may be susceptible to brittle fracture during start-up and shutdown. 885 °F (475 °C) embrittlement is a form of temper embrittlement that can occur in alloys containing a ferrite phase, as a result of exposure in the temperature range 600 °F to 1000 °F (316 °C to 540 °C). Affected materials are as follows. a) Primarily 2.25Cr-1Mo low alloy steel, 3Cr-1Mo (to a lesser extent), and the high-strength low alloy Cr-Mo-V rotor steels. b) Older generation 2.25Cr-1Mo materials manufactured prior to 1972 may be particularly susceptible. Some high strength low alloy steels are also susceptible. c) The C-0.5Mo, 1Cr-0.5Mo, and 1.25Cr-0.5Mo alloy steels are not significantly affected by temper embrittlement. However, other high temperature damage mechanisms promote metallurgical changes that can alter the toughness or high temperature ductility of these materials. d) Weld materials are generally more affected than today’s low-impurity base materials.

Table C.4—Machinery Failure Causes

Ref.	Cause	Cause Category
1.	Design error	Design
2.	Improper material—selected	Design
3.	Insufficient lubrication—inadequate	Design
4.	Operating outside limits—incorrectly specified limits	Design
5.	Software or controls failure	Design
6.	Vibration—harmonics/resonance	Design
7.	Manufacturing or fabrication error	Manufacturing
8.	Installation error—installed backwards, wrong torque loads	Installation
9.	Alignment failure	Maintenance
10.	Clearance, fit, or tolerance failure	Maintenance
11.	Improper handling—damage during handling	Maintenance
12.	Improper material—replaced	Maintenance
13.	Unbalance—installation	Maintenance
14.	Insufficient lubrication—wrong oil, etc.	Maintenance
15.	Maintenance error	Maintenance
16.	Operating outside limits—improper parts	Maintenance
17.	Vibration—misassembly issues	Maintenance
18.	Unbalance—fouling/wear	Operation
19.	Loss of power	Operation
20.	Operating error	Operation
21.	Operating outside design limits—operating beyond limits	Operation
22.	Vibration—off limits operation	Operation
23.	Documentation error	Management
24.	Expected wear and tear	Management
25.	Improper material—purchased	Management
26.	Management error	Management
27.	Management of spares—improper storage	Management
28.	Operating outside limits—MOC process	Management
29.	Process stream composition upset	Miscellaneous
30.	Extreme environmental conditions, earthquake, 500-year flood	Miscellaneous
31.	Other cause	Miscellaneous

Annex D
(informative)

Guideline on Risk Mitigation Task Selection

D.1 Purpose

D.1.1 General

This informative annex provides guidelines on the applicability and frequency of risk mitigation maintenance task types in addressing various failure modes and mechanisms. Each task selected should be based on the identified failure mechanisms and causes leading to the intolerable unmitigated risk. Annex D also provides example templates containing fundamental risk mitigation tasks, by API 691 Machinery type. This is not meant to be an exhaustive list, nor should these be considered always applicable. For API 691 Machinery, enhanced CM and other potential tasks beyond those in the Annex D templates should also be considered, as they may provide more effective overall risk mitigation. The intent is to select tasks that are the most effective as well as efficient in achieving required risk reduction, by addressing the target failure mechanisms/causes. If the task selection process is unable to effectively reduce the risk to an acceptable level, other risk mitigation options should be considered in order to sufficiently do so. These can include process modification, spare parts strategies, or other one-time or recurring actions. These types of recommendations will often require revisiting design or other nonmaintenance aspects of the machinery application.

D.1.2 Task Selection Guidelines

D.1.2.1 General

The mitigation task selection process is described in 6.4. Typically the specific task is selected based on FMEA (see 6.3) and/or RCM. The selected tasks are deemed effective in the mitigation, prevention, or detection of the failure. Typically, multiple competing tasks may target a single failure mechanism and often the operating company will perform a cost-benefit analysis to determine the most effective tasks to mitigate risks to acceptable levels. If no applicable task exists, then run to failure strategies might be considered providing the failure mode or mechanism is not safety related.

D.1.2.2 Task Type Applicability

The following provides guidance on the applicability of task types.

a) For CM tasks to be applicable, it should be possible to detect reduced failure resistance for a specific failure cause/mechanism, a specific task should be able to detect a potential failure condition, and there should be a reasonable, consistent amount of time between the first indication of potential failure and the actual failure (i.e. indication and detection are not so close, or coincident with failure so that there is some benefit from performance of the task).

b) For time-based PM tasks to be applicable, there should be an identifiable age at which the component displays a rapid increase in the conditional POF, a large proportion of the same equipment type should survive to that age, and it should be possible to restore the original, or near-original, failure resistance to the equipment through servicing, rebuild or overhaul, or replacement. Random failure mechanisms/causes can seldom be effectively addressed with time-based PM.

c) For FF tasks or operational tests to be applicable, the equipment should be subject to a failure cause/mechanism that is not evident to personnel during normal plant operations (hidden failure).

D.1.2.3 Task Selection Priorities

In the risk-based approach the selected mitigation tasks should be prioritized. This can be achieved by detailed FMEA (see Annex I). FMEA can be supplemented by using a concept of RPN. The RPN is a product

of three rating parameters: occurrence, detection, and severity. Occurrence is a rating value corresponding to the estimated expected frequencies of failures for a given failure cause. Detection is a rating corresponding to the likelihood that proposed task will detect a specific failure mode to prevent consequence. Severity is a rating indicating the seriousness of the effect of a potential failure mode the task is attempting to address. The goal is to reduce RPN.

There is no uniform RPN scale available across industry; therefore, each FMEA result that uses this concept is unique.

D.1.2.4 Task Frequency Consideration

Also part of the task selection process is the assignment of frequencies for the selected tasks. Frequency considerations vary with the type of task, but in general, the issues that should be addressed concerning task frequency can be summarized in the following questions.

a) How frequently would the failure mechanism that the task addresses be expected to occur?

b) Does the likelihood of the failure mechanism increase over time (age-related), or is it fairly constant for the vast majority of equipment life (random)?

c) How much time elapses between equipment failure initiation and functional failure?

d) Is there an adequate mechanism to measure the failure progression or component degradation?

When determining the frequency for condition-monitoring tasks, the frequency should be consistent with the time interval between the first indication of potential failure (a “threshold value”) and the actual time of failure. Scheduling should be a consideration for monitoring multiple pieces of equipment (vibration rounds, lube oil sampling, etc.). Operator round frequencies should also be considered to enable packaging of routine tasks (shift, daily, weekly, etc.).

In determining frequency for time-based tasks, past failure history and/or maintenance experience on similar equipment should be consulted, as should OEM input. Normally, the frequency will be based on the expected MTBF or the time between incidences of unacceptable degradation. Frequency consideration should also take into account level of risk exposure and needed risk mitigation.

When determining frequency for FF tasks, consideration should be given to expected frequency of demand, failure rate, and tolerability of failure on actual demand. Also, it should be remembered that performing the FF task may increase the amount of wear or degradation in the equipment and/or may place the system in an unsafe or abnormal condition.

D.1.3 Inspection Test and Preventive Maintenance (ITPM) Templates

D.1.3.1 Benefits and Limitations

The use of these templates will help in defining specific tasks for both minor and major maintenance activities in a cost-effective manner to manage and minimize risk.

The use of these maintenance templates to develop machinery specific maintenance plans will not compensate for:

a) inaccurate or missing information,

b) inadequate designs or faulty equipment installation,

c) operating outside the acceptable IOWs,

d) not effectively executing the plans,

e) lack of qualified personnel or teamwork,

f) lack of sound engineering or operational judgment.

The ITPM plans should be based on the following:

a) age of the machinery,

b) design of the machinery,

c) facility experience with the machinery,

d) industry best practices,

e) machinery risk level as determined in the previous sections of this recommended practice,

f) machinery service, i.e. continuous, intermittent, or standby,

g) OEM recommendations,

h) process conditions and variables,

i) relative condition of the machinery.

D.1.3.2 Fine Tuning of ITPM

Initial content of the ITPM should be considered as a starting point and to improve quality of ITPMs a continuous improvement feedback loop is required. This will help identify gaps and shortcomings of the initial ITPMs and allow ITPMs to be fined tunes to improve effectiveness.

There is a need for a balance between automated CM tasks and human supervision (operator rounds) to ensure the correct level of equipment CM against identified risks.

D.1.3.3 In the following tables (D.1–D.7), the task type descriptions are defined in 6.4.

Table D.1—Centrifugal and Screw Compressors

ID	Task Type	ITPM Tasks
1.	FF	Instrument testing and calibration Verify readiness/start-up of aux lube/seal oil pumps
2.	SV	Perform four senses (look, smell, touch, hear) inspection and report unusual findings
3.	SV	Inspect lube/seal oil reclaimer Check lube/seal oil reclaimer for proper operation
4.	SV	Check for leaks: process, lubrication, sealing, cooling
5.	CM	Monitor alarm panel(s) status
6.	CM	Continuous vibration monitoring or manual checks with hand-held vibration meter
7.	CM	Check bearing temperature
8.	CM	Survey lubrication system: level, pressure, temperature
9.	CM	Survey cooling system: level, pressure, temperature, filters
10.	CM	Survey sealing system: reservoir level, overhead pot level, pressure, temperature
11.	CM	Monitor lube/seal oil filter pressure drop, establish action levels, change or clean filter/strainer upon high differential pressure
12.	CM	Monitor speed
13.	SV	Monitor lube/seal oil sight glasses for flow
14.	CM	Monitor pressure drop across process gas inlet filter
15.	CM	Monitor process inlet and outlet temperatures and pressures, each stage
16.	SV	Visually inspect liquid level in all process knockout pots
17.	CM	Monitor and trend thermodynamic performance, e.g. flow, pressures, head, etc.
18.	SV	Survey seal oil degassing tank for proper flow and heater temperature and/or N_2 sparging function
19.	SV	Survey gas seal supply filter differential pressures and supply and separation gas system differential pressures
20.	CM	Obtain vibration trend data for compressors without transient data manager (TDM)
21.	SV	Draw sample of lube/seal oil and perform visual inspection for water and contaminants
22.	CM	Perform lube/seal oil sample analysis including ferrography, and flash point for seal oil and combined lube/seal oil, establish action levels (refer to ASTM D4378), trend results
23.	CM	Perform full spectrum vibration monitoring for noncontinuous monitored compressors. Establish baselines and action levels. Trend results.
24.	PM	Replace lube/seal oil (normally during major overhaul)
25.	PM	Grease bearings
26.	PM	Overhaul lube/seal oil reclaimer
27.	PM	Replace lube oil filters, clean and inspect filter housing
28.	PM	Replace seal oil filters, clean and inspect filter housing
29.	SV	Survey condition of supports, shims, baseplate, grout, foundation
30.	PM	Drain lube oil reservoir, clean, flush, refill at every turnaround or overhaul
31.	PM	Drain seal oil reservoir, clean, flush, refill, check sour pots
32.	PM	Remove and clean suction process gas strainer

Table D.2—Centrifugal Pumps

ID	Type	ITPM Tasks
1.	SV	Perform four senses (look, smell, touch, hear) inspection and report unusual findings Check for leaks: process, lubrication, sealing, cooling
2.	SV	Visually check lube oil for water and contaminants and change as needed
3.	SV	Verify supply of oil mist
4.	CM	Monitor speed
5.	CM	Check vibration level on permanent monitor
6.	SV	Survey lubrication system: level, pressure, temperature
7.	SV	Survey cooling system: level, pressure, temperature, filters
8.	SV	Survey sealing system: reservoir level, pressure, temperature
9.	CM	Monitor filter pressure drop, establish action levels, change or clean filter/strainer upon high d/p
10.	CM	Check suction and discharge pressure to insure adequate flow and avoid cavitation
11.	CM	Check vibration level with hand-held vibration instrument
12.	CM	Measure and record bearing housing temperature
13.	CM	Perform full spectrum vibration monitoring. Establish baseline and action levels. Trend results.
14.	CM	Perform lube/seal oil sample analysis including ferrography, establish action levels, trend results
15.	PM	Replace lube oil
16.	PM	Replace seal barrier fluid
17.	PM	Clean, inspect lube oil mist system
18.	PM	Check seal steam quench
19.	PM	Grease pump bearings
20.	PM	Inspect/repair lubricator
21.	PM	Visually inspect dry coupling and torque coupling bolts per vendor’s recommendations
22.	PM	Flush seal cooler, pump case jacket, and/or bearing housing jacket
23.	PM	Clean/inspect seal flush cyclone separator and/or orifice
24.	PM	Clean, inspect gear teeth, lubricate gear type coupling
25.	PM	Replace seal flush filter
26.	PM	Replace lube oil filters, clean and inspect filter housing
27.	PM	Replace seal oil filters, clean and inspect filter housing
28.	PM	Clean suction screens (discharge if applicable)
29.	SV	Survey condition of supports, shims, baseplate, grout, foundation
30.	PM	Clean lube oil system. Drain lube oil reservoir, clean, flush, refill. Clean/inspect orifice(s).
31.	PM	Clean seal oil system. Drain seal oil reservoir, clean, flush, refill. Clean/inspect orifice(s).
32	SV	Seal leakage (electronic sniff) monitoring

Table D.3—Gas Turbines

ID	Type	ITPM Tasks
1.	SV	Perform four senses (look, smell, touch, hear) inspection and report unusual findings
2.	FF	Instrument testing and calibration Verify readiness/start-up of aux lube oil pump
3.	CM	Monitor inlet and outlet temperatures and pressures, axial compressor and turbine sections
4.	CM	Obtain vibration trend data for gas turbines
5.	CM	Measure and record bearing housing temperature
6.	SV	Draw sample of lube/seal oil. Perform visual inspection for water, contaminants, etc.
7.	CM	Perform lube/seal oil sample analysis including ferrography, establish action levels, trend results
8.	PM	Replace lube/seal oil filters, clean and inspect filter housing
9.	SV	Survey condition of machine supports, shims, baseplate, grout, foundation
10.	PM	Replace inlet air filters
11.	PM	Overhaul lube/seal oil reclaimer
12.	PM	Perform operation surveillance (O/S) test—mechanical and electrical
13.	PM	Drain lube oil reservoir, clean, flush, refill
14.	PM	Drain seal oil reservoir, clean, flush, refill
15.	PM	Perform hot gas path inspection
16.	PM	Perform combustion inspection

Table D.4—Gear Boxes

ID	Type	ITPM Tasks
1.	SV	Perform four senses (look, smell, touch, hear) inspection and report unusual findings
2.	SV	Visually check lube oil for water and contaminants, change as needed
3.	CM	Check vibration level on permanent monitor
4.	CM	Survey lubrication system: level, pressure, temperature
5.	SV	Check for leaks: lubrication, cooling
6.	CM	Measure and record bearing housing temperature
7.	CM	Perform full spectrum vibration monitoring. Establish baseline and action levels. Trend results.
8.	CM	Perform lube/seal oil sample analysis including ferrography, establish action levels, trend results
9.	PM	Replace lube oil (normally during major overhaul)
10.	PM	Clean, inspect lube oil mist system
11.	PM	Clean, inspect, lubricate gear coupling
12.	SV	Survey condition of supports, shims, baseplate, grout, foundation
13.	PM	Check gear condition, spray bar oil flow, and bottom of gear box for cleanliness. Inspection cover must be removed.
14.	PM	Drain lube oil reservoir, clean, flush, refill
15.	PM	Perform a formal internal inspection per company and/or OEM recommendations

Table D.5—Reciprocating Compressors

ID	Type	ITPM Tasks
1.	SV	Perform four senses (look, smell, touch, hear) inspection and report unusual findings
2.	SV	Check for leaks from process, rod packing, lube oil and water jacket systems
3.	SV	Verify heat tracing on suction lines and dampeners is functioning correctly
4.	CM	Monitor inlet and outlet pressures and temperatures each stage
5.	SV	Monitor gas packing, valve covers, heads, piping for leaks
6.	CM	Monitor cooling jacket pressure, temperature, flow. Maintain supply temperature 10 to 15 degrees higher than gas inlet.
7.	SV	Monitor thermo-siphon verify glycol level
8.	CM	Monitor lube oil supply pressure, temperature, flow
9.	CM	Monitor lube oil filter pressure drop
10.	SV	Note condition of main oil pump
11.	SV	Note status of aux oil pump, aux oil pump on/off/auto switch
12.	SV	Monitor oil level in crankcase
13.	CM	Analyze compressor performers (Beta analyzer or equivalent). Compare to previous data.
14.	PM	Change/clean lube oil filters, clean filter housing and suction screens. Verify crankcase heater is functioning.
15.	PM	Replace lube oil (small reservoirs)
16.	PM	Grease lube oil pump bearings
17.	PM	Clean oil from motor bearing and pedestal
18.	PM	Clean, inspect gear teeth, lubricate gear type coupling
19.	PM	Clean process side inlet strainers/filters
20.	PM	Change process side inlet strainers/filters, clean filter housing
21.	PM	Inspect, retorque piston rod to crosshead joint
22.	PM	Retorque and ultrasonic testing (UT) inspect cylinder bolting, frame bolting, foundation bolting. Wet fluorescent magnetic particle (WFMT) tie bar bolting.
23.	PM	Retorque and 25 % random UT inspect bolting for valves, un-loaders, clearance pockets
24.	PM	Measure rod run out
25.	PM	Retorque and 25 % random UT inspect suction and discharge bottle bolting
26.	PM	Check and repair compressor pocket valves on all un-loaders
27.	PM	Clean/overhaul cylinder lube system, including reservoir, check, set lubricator rates
28.	PM	Clean or replace frame breather caps
29.	PM	Inspect crosshead shoes, retorque bolting to crosshead
30.	PM	Clean liquid knockout drums and drainer pots level gauges
31.	PM	Inspect piston rod/coatings in packing areas (use profile-meter to measure surface)
32.	PM	Retorque and UT inspect packing box bolting
33.	PM	Ensure suction snubber to drainer pot vents and drains are open, clear of pluggage, and free draining
34.	PM	Check pedestal bearing bolt torque

Table D.5—Reciprocating Compressors (continued)

35.	PM	Drain and clean crankcase, lube oil passageways, and piping; verify crankcase heater is functioning
36.	PM	Test relief valves
37.	PM	Inspect piston rings, rider bands thru cylinder head. Determine wear rates of rings and rider bands. Inspect cylinders for cracks, wear, taper, and out of roundness.
38.	PM	Remove and inspect or repair flow, pressure, and liquid level instruments on process side. Clean out taps.
39.	PM	Remove and dye check piston, piston rod, cylinder bore, pressure packing, valves. Check and record piston rod hardness.
40.	PM	Check wiper packing for wear, leakage
41.	PM	Clean deposits from cylinder and head water jackets
42.	PM	Inspect valve ports [using WFMT or penetration test (PT)]
43.	PM	Clean, inspect, and test interstage coolers
44.	PM	Inspect and clean suction bottles. Inspect discharge bottles.
45.	PM	Clean, inspect, and test lube oil cooler(s)
46.	PM	Inspect wrist pin, wrist pin bearing, X-head shoes. Check clearances. Replace retaining clips/springs.
47.	PM	Retorque and UT inspect tie bar bolting
48.	PM	Check main bearing clearance with feeler gauges, obtain web deflection readings
49.	PM	Retorque main bearing, connecting rod bolts
50.	PM	Retorque crankshaft to motor coupling bolts
51.	PM	Inspect crosshead and connecting rod eye for cracks, overheating
52.	PM	Inspect motor outboard bearing
53.	PM	Check bearing isolation—remove micarta shims and inspect/seal edges/replace as needed. Verify oil line isolation.
54.	PM	Check motor rotor and exciter air gap

Table D.6—Steam Turbines

ID	Type	ITPM Tasks
1.	SV	Perform four senses (look, smell, touch, hear) inspection and report unusual findings
2.	SV	Verify heat tracing on suction lines and dampeners is functioning correctly
3.	SV	Survey lubrication system: level, pressure, temperature
4.	SV	Survey cooling system: level, pressure, temperature, filters
5.	SV	Survey sealing system: reservoir level, overhead pot level, pressure, temperature
6.	SV	Check for leaks: steam, lubrication, cooling
7.	SV	Monitor lube/seal oil sight glasses for flow
8.	SV	Monitor alarm panel(s) status
9.	CM	Measure and record bearing housing temperature
10.	FF	Verify start-up of aux lube pumps
11.	SV	Inspect lube oil reclaimer Check lube reclaimer for proper operation
12.	CM	Check vibration level on permanent monitor
13.	CM	Check bearing temperature on permanent monitor
14.	CM	Monitor lube/seal oil filter pressure drop, establish action levels, change or clean filter/strainer upon high differential pressure.
15.	CM	Monitor speed
16.	CM	Monitor steam inlet, extraction, induction, and outlet temperatures and pressures
17.	CM	Note steam flow through machine and compare to normal
18.	CM	Obtain vibration trend data for turbines
19.	SV	Draw sample of lube oil. Perform visual inspection for water, contaminants, etc.
20.	CM	Perform full spectrum vibration monitoring for noncontinuous monitored turbine. Establish baselines and action levels. Trend results.
21.	CM	Perform lube oil sample analysis including ferrography, establish action levels, trend results
22.	PM	Replace lube oil (normally during major overhaul)
23.	PM	Grease bearing and/or shaft—turbines and lube oil turbines
24.	PM	Grease bearing and/or shaft —turbines and lube oil turbines
25.	SV	Survey condition of supports, shims, baseplate, grout, foundation
26.	PM	Grease steam rack
27.	PM	Flush/clean turbine oil reservoir(s)
28.	PM	Replace lube oil filters, clean and inspect filter housing
29.	PM	Clean and check gland condenser and air ejectors
30.	PM	Uncouple, perform O/S test—mechanical and electrical
31.	PM	Drain lube oil reservoir, clean, flush, and refill

Table D.7—Fans, Blowers, and Special Machinery

ID	Type	ITPM Tasks
1.	SV	Perform four senses (look, smell, touch, hear) inspection and report unusual findings
2.	SV	Survey lubrication system: level, pressure, temperature
3.	SV	Survey cooling system: level, pressure, temperature, filters
4.	SV	Survey sealing system: reservoir level, overhead pot level, pressure and temperature (as applicable)
5.	SV	Check for leaks: air, lubrication, cooling
6.	SV	Check main lube oil pumps for proper operation
7.	SV	Monitor lube/seal oil sight glasses for flow
8.	SV	Monitor alarm panel(s) status
9.	CM	Monitor speed
10.	FF	Verify start-up of aux lube pumps
11.	SV	Inspect lube oil reclaimer Check lube reclaimer for proper operation
12.	CM	Inspect coupling with strobe light (if possible)
13.	CM	Check vibration level on permanent monitor
14.	CM	Check bearing temperature on permanent monitor
15.	CM	Monitor lube/seal oil filter pressure drop, establish action levels, change or clean filter/strainer upon high differential pressure
16.	CM	Obtain vibration trend data for machineries
17.	CM	Measure and record bearing housing temperature
18.	SV	Draw sample of lube oil. Perform visual inspection for contaminants.
19.	CM	Perform full spectrum vibration monitoring for noncontinuous machineries. Establish baselines and action levels. Trend results.
20.	CM	Perform lube oil sample analysis including ferrography, establish action levels, trend results
21.	PM	Replace lube oil (normally during major overhaul)
22.	PM	Grease bearings (fan, blower, etc.)
23.	PM	Grease louvers
24.	PM	Clean, inspect lube oil mist system
25.	PM	Visually inspect dry coupling and torque coupling bolts per vendor’s recommendations
26.	PM	Flush/clean bearing reservoir
27.	PM	Inspect fan belts for proper tension, excessive wear and cracking; check alignment of pulleys from motor to fan shaft
28.	PM	Check fan bearings
29.	PM	Clean, inspect gear teeth, lubricate gear type coupling
30.	PM	Visually inspect fan blades for wear, erosion, etc., check pitch
31.	PM	Visually inspect and tighten structural bolting in fan shrouds and driver supports
32.	PM	PT (dye check) fan blades for cracks

Annex E
(informative)

Guideline on Condition Monitoring and Diagnostic Systems

E.1 Introduction

This annex provides practical guidance on the specification of CM and diagnostic systems for API 691 Machinery. Key to identifying the diagnostic needs that support effective maintenance task selection (Section 6) is conducting a PFMEA (Annex A) to accurately define the CM technology, parameters, data, collection frequency, etc. in order to provide the earliest detection of machinery faults.

NOTE ISO 17359 [26] may be useful to operators developing a CM program.

E.2 The Basic Principles of Condition Monitoring

E.2.1 This section includes the attributes that need to exist before any type of on-condition maintenance, including manual inspection and basic and condition monitoring, can be applied. Not all failure modes will be applicable to CM, and so CM (whether it is labeled predictive or advanced technology) will always be a subset of the overall maintenance regime if CM tasks are chosen.

E.2.2 Figure E.1 provides a pictorial view of the progression of incipient failure and how this degrades toward a point of functional failure showing all of the salient points important in on-condition maintenance. The point of detectability is when a potential failure can be detected with the technologies being utilized in the operational context of the observed machine. The P to F (potential to functional) time is that which may be used to take action to avoid the functional failure consequences. The P-F interval will have a natural variance between different failure events of the same type, and variance may also be influenced by differences in operating regime and the operating environment.

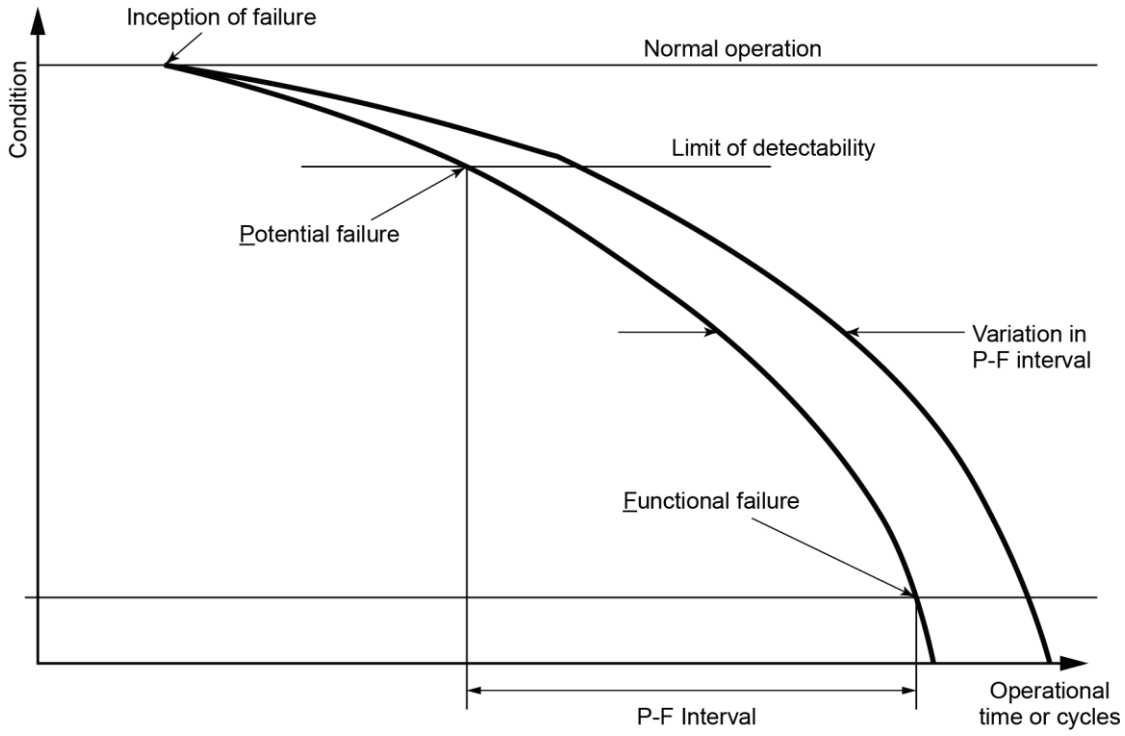


Figure E.1—Illustration of the Basic Principles of Condition Monitoring

The normal acceptable operating band may also have variance and may change over time (especially as components gradually wear). The observed variance may also be due to noise in the sampled data.

The identification of what is the functional failure line is obvious in some cases; however, in other cases the difficulty in agreeing this should not be underestimated. Reference to other standards should be used.

The inception of failure may start as soon as a machine is introduced into its operating environment (e.g. exposure to corrosion) or may be an initiating event that can happen at any time in operational life (e.g. a bearing failure may be initiated by a shock load condition).

E.2.3 Required Prerequisites for Condition Monitoring

The following list outlines the behaviors of the failure modes and conditions that need to exist before any type of practical and effective on-condition maintenance may be applied.

a) Sensors and data exist that are able to be used to detect a precursor condition or symptoms that are indicative of a failure mode.

b) Suitable data shall be accessible in a timely manner.

c) There shall be sufficient time between the diagnosis (detection) and the point of functional failure to allow practical and cost-effective remedial action to be taken (see Figure E.2).

d) The variation in P-F interval for different instances of the same failure mode should be reasonably small, such that the calculation of time to functional failure (RUL) has an acceptable degree of certainty.

e) The standard for and levels of functional failure needs to be agreed and defined with the asset stakeholders, such that the P-F interval may be determined.

f) The application of CM is practical and cost-effective.

For CM to be considered as a risk-mitigating task in the API 691 PFMEA, then the above criteria need to be applied to each failure mode and then calculated to determine the overall value of the CM system.

E.2.4 The prerequisite list above also needs to include two considerations when considering the acquisition and specification of a CM system. For all failure modes covered by a CM task:

a) how much warning time does CM need to deliver to:

   1) allow planning and predisposition of resources to effect the fastest and most effective recovery,

   2) identify the best time to shut down the machinery to have minimum impact on production or product quality;

b) what is the level of granularity of isolating fault conditions and failure modes required given the requirement to accurately identify the correct spares, the depth of machinery strip, and the likelihood of other induced damage, for the most effective and efficient recovery of the machinery back into service.

These considerations may influence what CM techniques are applied, in order to deliver the required warning time and granularity of fault isolation criteria.

E.2.5 Consideration of Operating Context and Environment

It is also important to understand that the impact and likelihood of failure may be significantly influenced in variations of build, operating context and environments. These variations need to be fully taken into account when specifying a CM solution. The following diagram outlines these major factors, which should be applied to the FMEA studies.

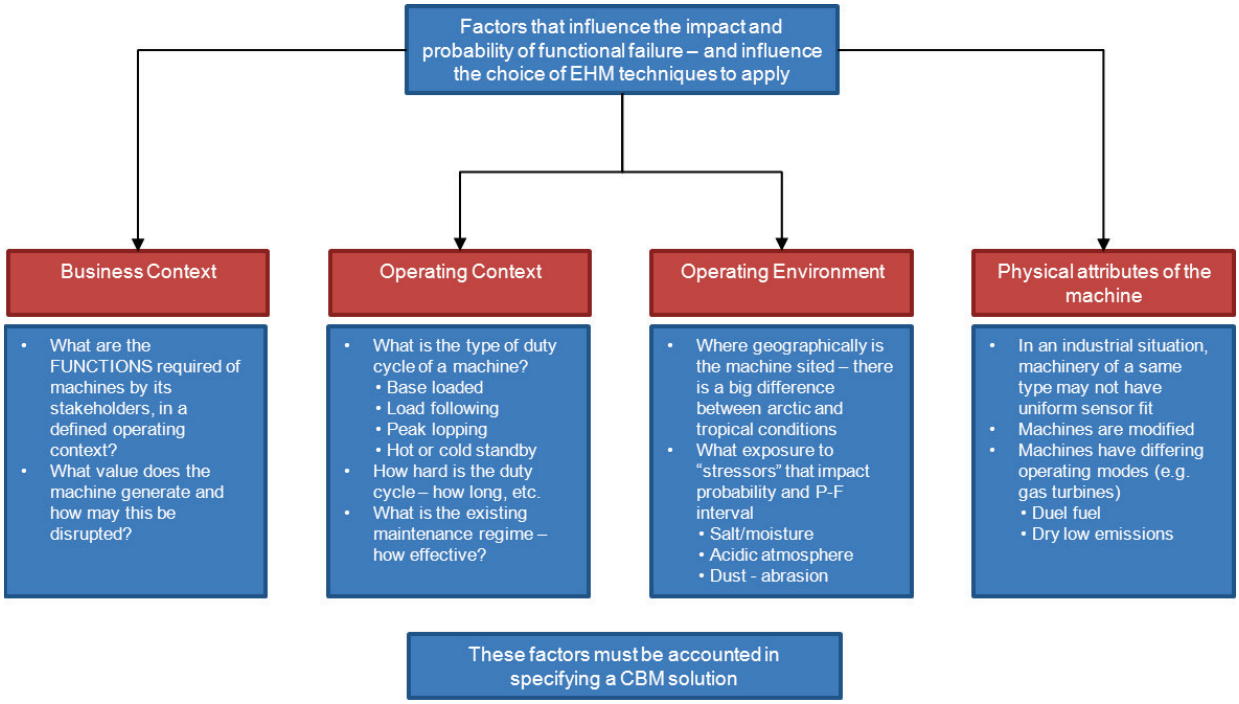


Figure E.2—Influences on Functional Failure and Condition Monitoring Specifications

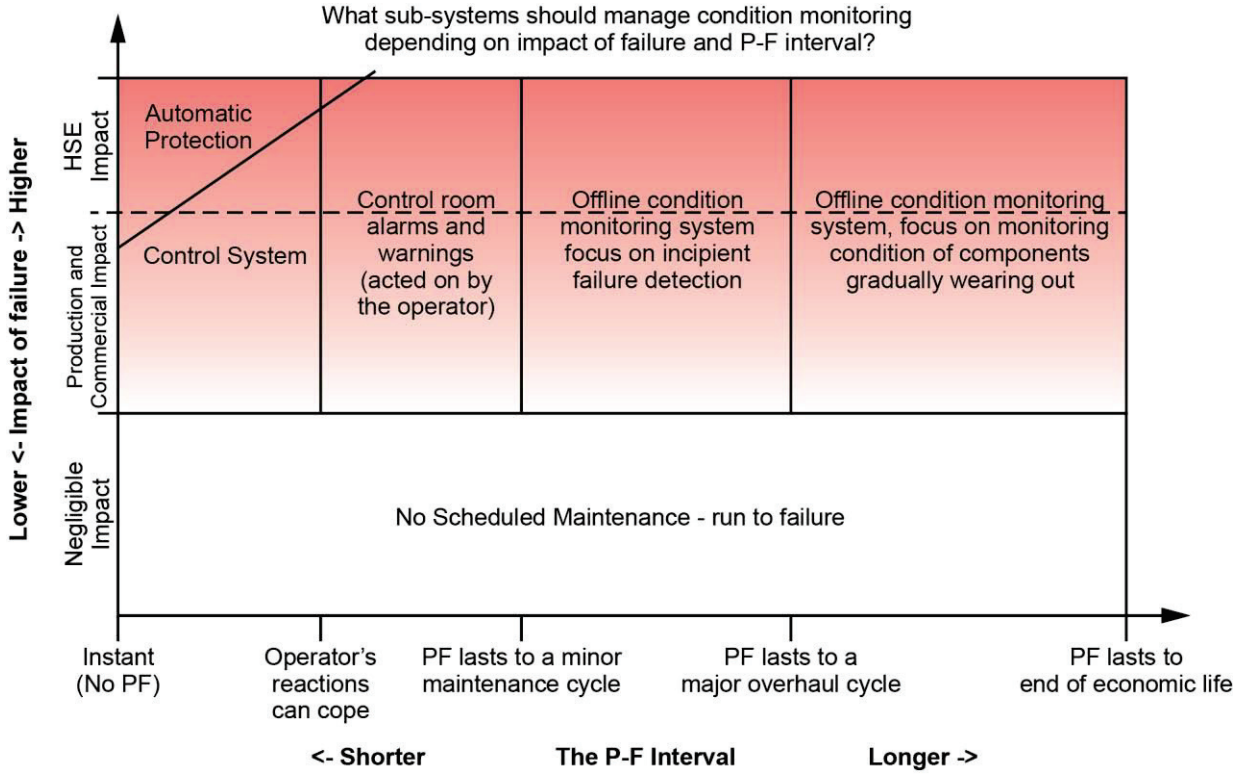


Figure E.3—Subsystem Boundary Guidance for the Assignment of CM Tasks

E.2.6 Determination of Subsystems to Assign Condition Monitoring

A further consideration to assign subsystems to assign CM tasks is by comparing the natural P-F interval of a machine's failure modes to the impact of failure of the machine in its operating context. Any critical machine may have components that may or may not be HSE critical, and there may be considerable economic benefit in applying CM tasks to mitigate failures with operational production or economic impacts. Figure E.3 illustrates where CM functions should be applied. The boundaries drawn in the following diagram are for illustrative purposes and the actual boundaries and rules for assigning CM tasks will need to be conducted by individual organizations.

E.3 Condition Monitoring Approaches and Techniques

E.3.1 General

This section provides a basic breakdown of common CM approaches and associated techniques that can be applied when developing a maintenance regime. This is not an exhaustive list.

The following commonly applied approaches will be covered:

a) vibration analysis (this would include acoustic analysis),

b) tribology, particularly oil and oil debris analysis,

c) chemical monitoring,

d) performance analysis (uses process data),

e) electrical monitoring,

f) thermography,

g) stress or duty cycle counting.

E.3.2 Machinery Faults Matched to Condition Monitoring Techniques

Table E.1 shows primary and secondary techniques that are commonly applied today for API machinery and a selection of their most common failure modes. As part of risk mitigating task section described in 6.4, it may be desirable to consider the application of several CM techniques to improve certainty of risk reduction.

This table is not exhaustive and some of the choices of whether particular techniques can be subjective. The table does represent a consensus view from a number of CM experts. The first section of the table includes common faults that are seen on the majority of all rotating machines.

Table E.1—Machinery Faults Matched to Condition Monitoring Technology

Machine Type	Condition Monitoring Technology (P—Primary; S—Secondary)							
Examples of Faults	**Vibration Analysis**	**Acoustic Analysis**	**Performance Analysis**	**Tribology Analysis**	**Chemical Monitoring**	**Electrical and Magnetic Waveform Analysis**	**Thermography**	**Stress or Duty Cycle Counting**
Common Rotating Machinery Faults (Driven Asset)								
Bearings (rolling)	P	S		S		S	S	
Bearings (thrust)	P	S	S	S		S		
Bearings (fluid film)	P	S		S		S		
Gears	P	P		P		S		
Out of balance	P	S				S		
Shaft misalignment	P	P				S		
Loose foundation	P	P				S		
Coupling wear	P	P				S		
Belt slippage	P	P				S	S	
Corrosion					P			
Cooler—heat exchangers		S	P				S	
Structural—containment		S			S	P		
Inefficient operation			P			P		
Pump Specific Faults								
Damaged/impacted impeller	P		S			P		
Cavitation	P		P			P		
Eccentric impeller, blocked impeller	P					P		
Seal damage/leakage	S		P			S	S	
Gas Turbines (Industrial)								
Air inlet blockage	P		P					
Compressor fouled	P		P					
Compressor damaged	P		P					S
Fuel filter blockage			P					
Combustion chamber holed			P					
Burner blocked	P		P					
Power turbine damage	P		P					

Machine Type	Condition Monitoring Technology (P—Primary; S—Secondary)							
Examples of Faults	Vibration Analysis	Acoustic Analysis	Performance Analysis	Tribology Analysis	Chemical Monitoring	Electrical and Magnetic Waveform Analysis	Thermography	Stress or Duty Cycle Counting
Gas Turbines (Aero-derivative)								
Air inlet blockage			P					
Compressor fouled	P		P					
Compressor stall	P		P					
Fuel filter blockage			P					
Combustion chamber holed			P					
Burner blocked	P		P					
Power turbine dirty	P		P					
Blade/vane fatigue life	P							P
Hot end thermal coating dissipation			S					P
Power turbine damage	P		P					
Steam Turbine Specific Faults								
Damaged rotor blade	P		S					
Centrifugal Compressor								
Damaged impeller	P		S			P		
Damaged seals	P		P			S		
Eccentric impeller	P					P		
Cooling system fault			P					
Valve fault	P		P			P		
Reciprocating Compressor								
Inlet blockage	P					S		
Piston ring wear			P					
Flywheel damage	P							
Mounting fault	P					S		
Cylinder valves flutter			S			P		
Discharge line resonance	P							
Discharge valve leakage		P	S					
Connection rod wear	P			P		P		

Machine Type	Condition Monitoring Technology (P—Primary; S—Secondary)							
Examples of Faults	**Vibration Analysis**	**Acoustic Analysis**	**Performance Analysis**	**Tribology Analysis**	**Chemical Monitoring**	**Electrical and Magnetic Waveform Analysis**	**Thermography**	**Stress or Duty Cycle Counting**
Electrical Generators								
Rotor windings, uneven rotor-stator gap						**P**		
Stator windings						**P**		
Eccentric rotor	**S**					**P**		
Brush(es) fault						**P**		
Insulation deterioration						**P**		
Loss of output power phase	**S**					**P**		
AC Electrical Motors								
Caged rotor bar cracks	**S**					**P**		
Grounded or shorted field windings			**S**			**P**		
Rotor-stator air gap eccentricity						**P**		
VFD improper performance						**P**		
High resistance terminals/joints						**S**	**P**	
Fans								
Damaged impeller	**P**					**P**		

The following international standards may be useful to understanding and implementing the condition monitoring technologies noted above:

c) ISO 13373-1, [27]
d) ISO 13373-2, [28]
e) ISO 13373-3, [29]
f) ISO 22096, [30]
g) ISO 13380, [31]
h) ISO 14830-1, [32]
i) ISO 18434-1. [33]

E.4 A Conceptual Model for the Application of Condition Monitoring

E.4.1 General

This section provides a conceptual model for the application of CM techniques described in E.3.

Figure E.4 shows a block diagram of the major stages in the operational cycle. This model is useful in dividing a CM system into logical blocks such that all aspects of the operational cycle may be appropriately addressed in CM system design or integration. This process is cyclic and repeats. Each block is further described below.

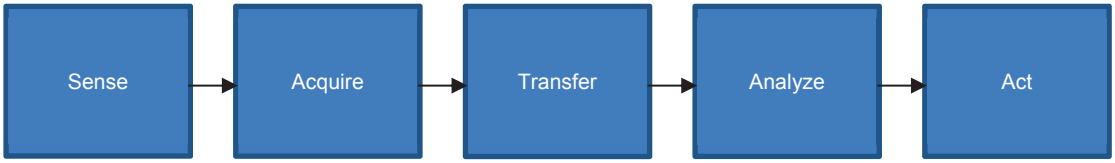


Figure E.4—CM Operational Life Cycle

E.4.2 Sense

The sense step represents the sensors and measuring devices that provide the raw data necessary to conduct CM. Sensor specifications should be evaluated for suitability using relevant parameters such as accuracy, tolerance, stiction, and hysteresis to ensure they are fit for purpose for the analysis. Data should be converted from analog to digital and be presented in engineering units to the CM system.

E.4.3 Acquire

E.4.3.1 General

The acquire step ensures the data are captured and stored at a sample rate commensurate with the analysis requirements. Acquisition is usually done by a specific firmware (in the case of dynamic data) and may undergo transforms [such as fast Fourier transform (FFT)] to convert frequency domain to time domain data. Local acquisition functions may conduct further processing of data, including machine state detection (which may adjust data sampling between “transient” and “steady” states), and locally store these data before transfer to a point where analysis is conducted. Data may need to be preprocessed to reduce volumes for economic transfer or may be subject to compression and encryption to help ensure privacy and convenient transfer of the data. Timeliness and completeness of transfer are very important aspects of the system.

Data may be sensed and acquired by handheld systems. These data may be analyzed locally and/or may be uploaded to a central repository.

Data historian systems may be integral with a CM system, where data are fed from and results fed back to the historian from a CM system.

E.4.3.2 Data Acquisition and Sampling Considerations

E.4.3.2.1 As part of specifying CM, it is important to understand how symptoms of failure present themselves in the data and how these symptoms may be detected. This implies differing data sampling acquisition needs. The following paragraphs explain the concepts.

E.4.3.2.2 Data sampling falls into three domains: dynamic, transient, and steady state. Machinery can operate in both transient and steady states and displays dynamic behavior. The terminology used for machine states and sampling regimes is similar, and care needs to be taken to distinguish between them. When CM is being considered to detect failure modes after the detailed FMEA analysis, it is important to determine how

symptoms of the failure mode present themselves, which requires a selection of techniques described above and their underlying data sampling rates.

a) Dynamic sampling is captured at rates in a range of KHz to over 100 KHz (with sampling ranges growing as technology develops). This sampling is generally intended to capture machinery dynamic behavior (machines do not have a dynamic state). Dynamic data may be subject to filtering and transforms (e.g. an FFT) to derive a series of spectra over time. The timing for these derivations may align with steady state (e.g. one FFT done every hour, with a machine in the steady state condition) or the transient state (e.g. one FFT is done every tenth of a second with the machine in the transient state) in order to observe a transient feature (e.g. showing how resonance of a rotor relates to its speed during a start-up or rundown).

b) Transient sampling is captured at rates typically in a range of 1 to 100 Hz, in order to capture transient features when the subject machine is in a transient state. An example of this may be capture of an electrical induction motor start torque characteristic, where the degradation of the start torque is indicative of rotor bar damage.

c) Steady state sampling is typically captured in a range of 10 minutes to several hours whilst the subject machine is in the steady state condition. Steady state sampling may also be conducted periodically. As long as the sampling periodicity is a fraction of the underlying P-F interval, this regime is valid.

E.4.3.2.3 In general, dynamic sampling used in online vibration analysis is very common; however, equally effective is using physical performance parameters (temperatures, pressures, flows, etc.), which is otherwise usually conducted using steady state analytics. An example of using dynamic monitoring of physical parameters is to use a pressure sensor to determine when a gas turbine's blades are fluttering, by observing the symptomatic high-frequency ripples in the pressure signal.

E.4.3.2.4 The determination of what sampling rates to use is as follows.

a) For dynamic and transient analysis, the data sampling rate is a function of the Shannon-Nyquist laws, which state that if features are to be reproduced in the data, then the sampling rate shall be at least double the period of that feature. This is a mathematical limit, and in practical terms the sampling rate should be 5 to 10 times the period of the underlying feature being observed. This is also important, as this will also determine the capability of the underlying sensors and their signal processing.

b) For steady state analysis the sampling rate is determined by the shortest P-F interval in the set of failure modes being addressed by steady state analysis.

In all cases the sampling rate shall be a fraction of the P-F interval, delivering enough warning time, to take practical actions to avoid failure consequences.

E.4.3.2.5 Where data sampled at different rates need to be fused to provide an accurate picture of condition or health, synchronization of the data in the time domain is important. CM systems should use Universal time (UTC) to ensure all sampling has a common baseline.

E.4.3.3 Machine State Detection

Some data acquisition systems may capture data at a transient rate, deriving steady state data as required. In order to derive steady state data, a form of machine-state detection is necessary to ensure derived steady state data is only produced when the subject machine is in the steady state condition. If data captured in a machine's transient state are supplied to analytics designed to deal with steady state conditions, it will result in false alerts, and late or missed detection of incipient failure.

E.4.4 Transfer

This step represents the transfer of data from the acquisition device local to the equipment to a centralized point for further analysis. In order to guarantee receipt of the data, reliable data transfer protocols should be used. Sometimes "message brokering or queuing" systems may be included, which will guarantee delivery of

the data, even if communication is temporarily broken. These systems include integral encryption and lower level functions such as checksums to ensure data are received as sent.

E.4.5 Analyze

E.4.5.1 General

Analyze is the part of the process that looks for the symptoms of failure in the sensor data and conducts diagnosis, prognosis, and notification of the fault conditions. The analyze block may be broken down further to look at typical modules found in a typical CM application. Figure E.5 illustrates a possible breakdown of the analyze block.

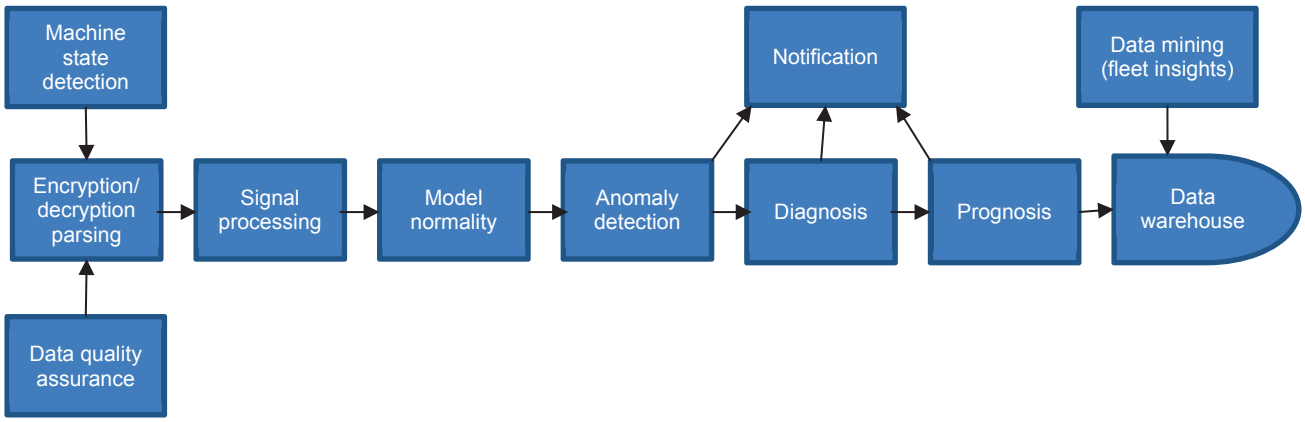


Figure E.5—Breakdown of "Analyze" for CM

The following subsections explain in more detail what the blocks in Figure E.5 mean. This diagram does not imply all of these steps are necessary, but they do constitute best practice.

E.4.5.2 Encryption, Decryption, and Parsing

Encryption may be necessary to ensure privacy. Some means of data transfer may automatically apply encryption (e.g. secure sockets or secure FTP). Parsing indicates that some data transforms may be necessary to turn the input data into a form that can be processed by the analytics. These transforms may be system specific.

E.4.5.3 Signal Processing

Signal processing may be applied in several places in the flow, but is best applied as far upstream in the data flow as practically possible. The assumption is that analog to digital conversion has occurred, but that transforms such as FFT may be necessary on dynamic data.

E.4.5.4 Data Quality Assurance

There may be data quality assurance rules that may be applied to input data to check for missing data, ensuring data can be associated with real machines in the field, and to determine data errors such as outliers resulting from failed sensors. The data quality assurance rules may be embedded and automated either in a rule base or embedded in a data ETL tool (Extract-Transform-Load). Sometimes these data transformations are labeled "data ingestion."

E.4.5.5 Machine State Detection

Data sampled at transient rates (usually 1 to 100 Hz) may be split into steady and transient state groups. Most analytics and analysis is conducted in the steady state, but a minority of failure modes may only present themselves in the transient state. Some transients are also particularly useful to separate for individual analysis, such as machine start-up and rundown analysis.

E.4.5.6 Model of Normality

Modeling normal machine behavior may be a tacit skill inherent in an expert analyst (they have the ability to spot abnormal machinery behavior from raw data) or it may be achieved using models of normality. Models may be produced from using look-up tables, first principles physics, or an empirical model trained from baseline data. The constructed model is supplied with some of the sampled data to set initial conditions, and the model then predicts what the other important sensor data will be. The corresponding raw sampled data are subtracted from the model predicted data to produce a residual signal. The advantage of doing this is that any deviation of the residual signal from zero (zero is considered normal) is indicative of abnormal behavior. This deviation is far easier to observe compared with trying to observe it from the raw data (which requires expert trained analysts). The introduction of models of normal behavior reduces the need for expert analysts to spend time reviewing detailed data and makes them more productive (they can manage more machinery).

Some parameters may be derived from sensor data using calculations or formulas. Examples of these may be calculations to swap engineering units or derive power or efficiency trends.

E.4.5.7 Anomaly Detection

Anomaly detection may be a set of analytic algorithms to detect threshold violations, step or rates of change, or changes in variance that may indicate a change-point in the time series data trends (usually the residual signal). For transient analysis, pattern-matching algorithms may be employed to detect undesirable changes. Other anomaly detectors may be employed including cluster analysis, support-vector machines, and where multiple parameters are used, other algorithms may be used to reduce “dimensionality” to make analysis easier, e.g. principal component analysis (PCA).

E.4.5.8 Diagnostic Classification

Diagnostics are always carried out, either manually or using classification algorithms.

There are hundreds of suitable algorithms derived from statistics, machine learning, and artificial intelligence that may be applied to automating CM analytics, which improves the productivity of the skilled analysts and diagnosticians.

One important consideration in the choice of analytics is how understandable their internal logic is in determining an output to humans. This factor helps a machinery stakeholder make a decision of withdrawing a machine from service, as they are able to comprehend what caused an automated system to issue an alert.

Algorithms such as neural networks and their means of logic are difficult to understand, compared to a deterministic rule base. Neural networks may not be an optimal choice for a diagnostic classifier for this reason.

E.4.5.9 Prognostics (Regression)

Prognosis is generally done and can be conducted manually or by using suitable analytics.

Part of prognostics is the calculation of RUL. RUL is covered in detail in Annex F where all the main approaches to derive RUL are covered. Ideally prognostic information also includes what is likely to happen at a point of functional failure and what and how long are options to effect recovery of the machinery. If sufficient data have been collected around the same type of historical failure event failures, this may be used to calculate “certainty” boundaries of the current prognostic projection so that variation and appropriate risk-based decisions may be taken.

E.4.6 Act

The last stage of CM is to alert (or notify) relevant machinery stakeholders that incipient failure has been diagnosed. This notification ideally includes prognostic information about RUL, its bounds of certainty, and the effects or consequences of failure and recovery. There needs to be an automated distribution list for alert recipients, and the alerts should contain sufficient contextual and supporting evidence to enable recipients to trust the CM system is not falsely alerting. There need to be established business processes that determine the actions necessary by the recipients in order to successfully avoid functional failure consequences. If the CM diagnosis is uncertain, then further troubleshooting may need to be initiated to confirm a fault condition. Once a fault is confirmed, planning and preparation for recovery may commence. Further alerts may need to be issued as the failure deteriorates and the prognostics update. In order to extend RUL, it may be worth considering reduced load on the effected machine.

These downstream actions may be managed by a maintenance management system (MMS) or EAM system. It may be possible that CM notification triggers automated work tasks in the MMS or EAM, but in the majority of cases authorization to release maintenance tasks will be manual.

E.5 Advancements in Condition Monitoring

Table E.2 suggests some distinctions between regular traditional approaches to CM and those more advanced approaches that have emerged in recent years. The term advanced condition monitoring is not meant to be a hard definition, because it is a qualitative judgment on aspects of CM, and what is advanced today will be mainstream tomorrow. However, CM is in a state of rapid technical development, and this section emphasizes the point that asset managers would be wise to understand what is state of the art and what disruptive changes (that may challenge deeply held assumptions and value in the industry) are emergent from the CM domain.

Table E.2—Comparison of Basic CM to Advanced CM

Basic CM	Advanced CM
Relies on human experts to interpret raw or semi-processed data to diagnose and prognose. Calculations may be manual. Tends to use single standalone techniques. Fusion of information is done manually.	Tends to be highly automated using signal processing, applied machine learning, artificial intelligence, and statistical methods applied to diagnostics and prognostics. Automatically fuses several techniques and data from other influencing systems. The presentation of symptoms may occur at different times from different techniques that the advanced CM system uses as further diagnostic information.
Tends to use steady state analysis, even when extracting information from dynamic behavior (such as vibration) analysis.	Exploits both steady and transient state analysis, augmented by dynamic behavior analysis.
Tends to use single variables that indicate a change or departure from normal behavior. Diagnosis of failure modes is routinely conducted by a human expert.	Uses multivariable approach, using patterns of “features” from several variables that uniquely indicate failure modes. Diagnosis is routinely automated.
May be restricted to higher levels of machinery breakdown, may only detect symptoms that need further troubleshooting.	Provides more granular information that results in more effective preventative correction. Allows the detection of more complex evidence to isolate faults at component levels and identify causal failure mechanisms.

Annex F
(informative)

Guideline on Machinery Prognostics

F.1 Introduction

F.1.1 Machinery prognostics use historic, current, and forecasted operational and maintenance data to predict the RUL of the machine and proactively manage pending loss of function or failures. The objective is to give those responsible for asset management additional tools to deliver consistent machinery operation, reduce lost production, lower maintenance cost, optimize equipment spares investment, and improve safety through proactive maintenance, maximizing equipment performance. The random occurrence of failures is a result of variations in equipment degradation rates, which makes it difficult to predict when the accumulation of degradation will lead to equipment failure. These variations occur for a number of interactive reasons such as:

a) current equipment condition,

b) running hours,

c) cycle times,

d) operating conditions,

e) process operating windows,

f) variation in equipment loading,

g) contamination of operating material,

h) maintenance strategies and actions.

Prognostic models use automated methods to observe the degradation process of equipment and predict the RUL of the equipment with some confidence on that prediction. Where possible, actual feedback on current conditions will improve the accuracy of the prediction as this information may provide an understanding of the physical degradation process [34].

F.1.2 Remaining Useful Life

In order to address the deterministic nature of the installation, potential failure, failure (IPF) approach, a mechanism is needed to convert failures in time to POF over time with confidence intervals on these answers. This is what is known as remaining useful life (RUL), and an example of these curves can be seen in Figure F.1. This figure illustrates that additional quality information obtained within the context of consistent operations may improve the results.

RUL distributions frame the answer around the likelihood of reaching a specific point in time before the failure occurs with a given confidence. This approach addresses the problem that occurs when the subject matter expert (SME) makes his/her best estimate, by providing a more realistic view of the POF.

The first illustration of this can be seen by observing the solid red line in Figure F.1. In this case, the simplest answer given by the SME would be, “I have an 80 % confidence that it will be at least 33 days before this failure occurs.” This approach is a significant change from traditional thinking and provides flexibility in the exact time the failure will occur because, by definition, some failures will occur earlier and some will occur later than the identified failure point.

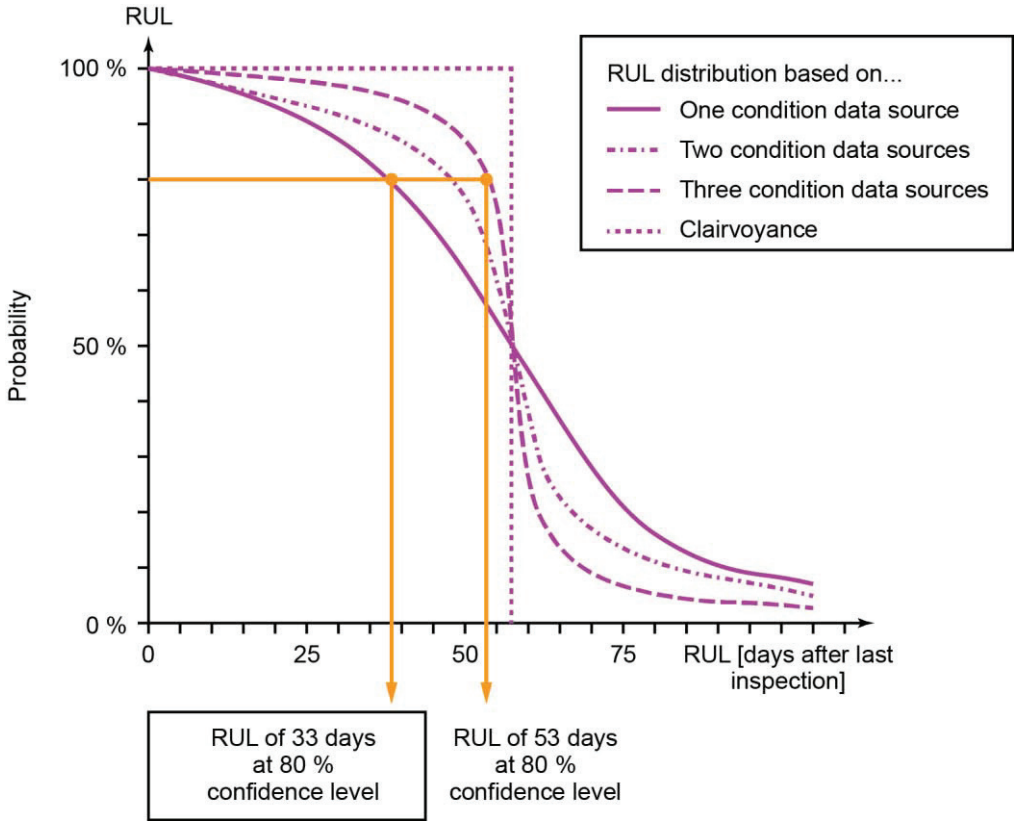


Figure F.1—RUL Curves [35]

F.1.3 Advanced Predictive Systems

The application of diagnostics and predictive technologies, known as predictive maintenance, has become the mainstay of many asset strategies (refer to Figure F.3, Type 1 and 2.). This approach provides a significant improvement in the cost of maintenance and, when applied correctly, knowledge that equipment is on the P-F portion of the IPF curve and that a failure(s) is impending. This is of great value to the operators of industrial facilities who can take preemptive corrective action before the functional failure has occurred, thereby avoiding unexpected downtime that reduces the risk of HSE events associated with unplanned shutdowns and the lost production impacts that often accompany these.

Despite the benefits of PDM, when compared to time-based preventive systems, the application is limited because of the following.

a) Predictive technologies are a backward looking equipment monitoring function only finding an impending failure after the equipment has entered the P-F portion of the failure curve. Vibration monitoring, for example, can detect high axial vibration on a thrust bearing when deviations from baseline are observed, but may not be able to shut down the machine before failure has occurred due to the failure degradation rate (i.e. the P-F interval).

b) The ability to extend the useful life of the equipment is limited by the detection time of the abnormality, the SME's cognitive ability to diagnose the fault, and the frequency of observation. For example, lube oil contamination for a given machine may occur within the sampling frequencies and therefore bearing failure may be unavoidable without additional detection methodologies.

F.1.4 Definition of Prognostics

Prognostics are a class of mathematical models, statistical and physical, that are used in the monitoring of equipment and producing an estimate of the RUL of the equipment, systems, or components. A wide range of models have been developed and some of the more common ones are:

a) failure time distribution,

b) proportional hazard model (PHM),

c) Markov chain model (MCM),

d) shock models,

e) general path model (GPM),

f) exploration models,

g) models combining different techniques.

F.1.5 The Relationship of Prognostics to Condition-based Maintenance

Condition-based maintenance (CBM) is a maintenance program that recommends actions based on information collected through CM. This is an important development in maintenance strategy development as equipment deteriorates over time. The rate of degradation may vary based on operating conditions, usage shock, materials, operating conditions, etc., and this process is often nonlinear. By using information that can be collected on equipment health and operating decisions, more informed maintenance decisions can be made. The CBM process has three steps:

a) data acquisition,

b) data processing,

c) maintenance decision making.

Predictive maintenance technology, diagnostics, and prognostics are all part of a robust CBM program (refer to Figure F.3, Type 3). While diagnostics are a posterior event analysis and prognostics are a prior event analysis, there is an important relationship between the two [36]. This is because prognostics often rely on diagnostic outputs as inputs and these should be considered together. This relationship is illustrated in Figure F.2 shown below.

Prognostics are integral to any CM. This may be generalized into a number of regimes, two of which may be the following.

a) *Regime 1—Incipient Failure Detection*. This is where a failure may be initiated at any time in the service life of a machine, and once the CM has diagnosed that the asset is in the potentially failed state, prognosis of the RUL may then be undertaken.

b) *Regime 2—Monitoring Long-term Degradation*. Many assets start to deteriorate as soon as they are introduced to their operating environment; there is no discrete inception of failure as seen in incipient failure detection. Many of these deterioration factors define the trigger for major maintenance or overhaul, or define the end of asset economic life. Prognostics has the task of accurately monitoring the conditional deterioration and accurately forecasting RUL, where major maintenance is due, or the asset needs to be retired.

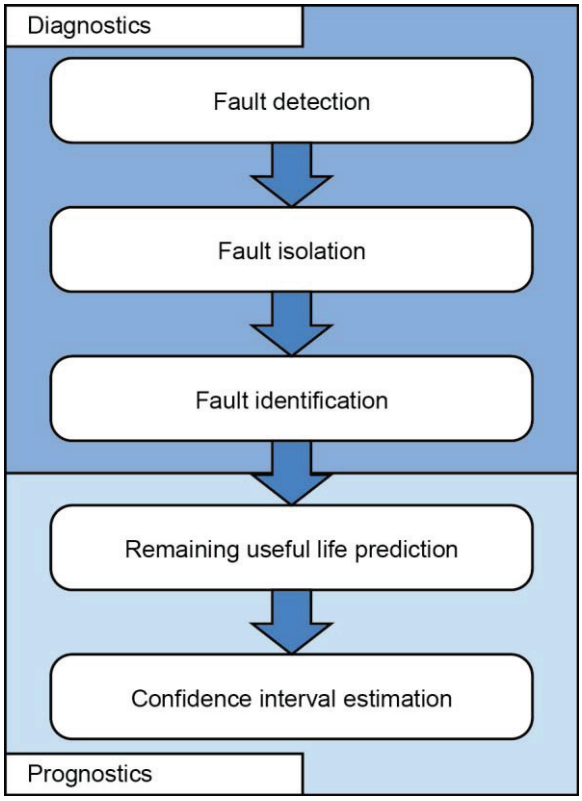


Figure F.2—Relationship Between Diagnostics and Prognostics

F.2 Prognostic Models Classification

F.2.1 Introduction

Prognostic models endeavor to present a future state of equipment health by utilizing RUL as discussed earlier. Some prognostic approaches integrate multiple data sources and modeling techniques to provide a more accurate prediction of equipment health and is illustrated in Figure F.1 as a dashed line. In this case, additional data improve the accuracy of the prediction. Luo et al. developed an interacting multi-model approach to model-based prognostics [37].

A basic methodology for prognostics can be summarized as follows [38].

a) Collect historical data.

b) Perform FMEA to identify the failure modes of greatest interest.

c) Develop any additional data as necessary, e.g. failure testing.

d) Clean and select the data.

e) Identify and develop the appropriate class of prognostic model.

f) Validate prognostic model.

g) Implement prognostic model.

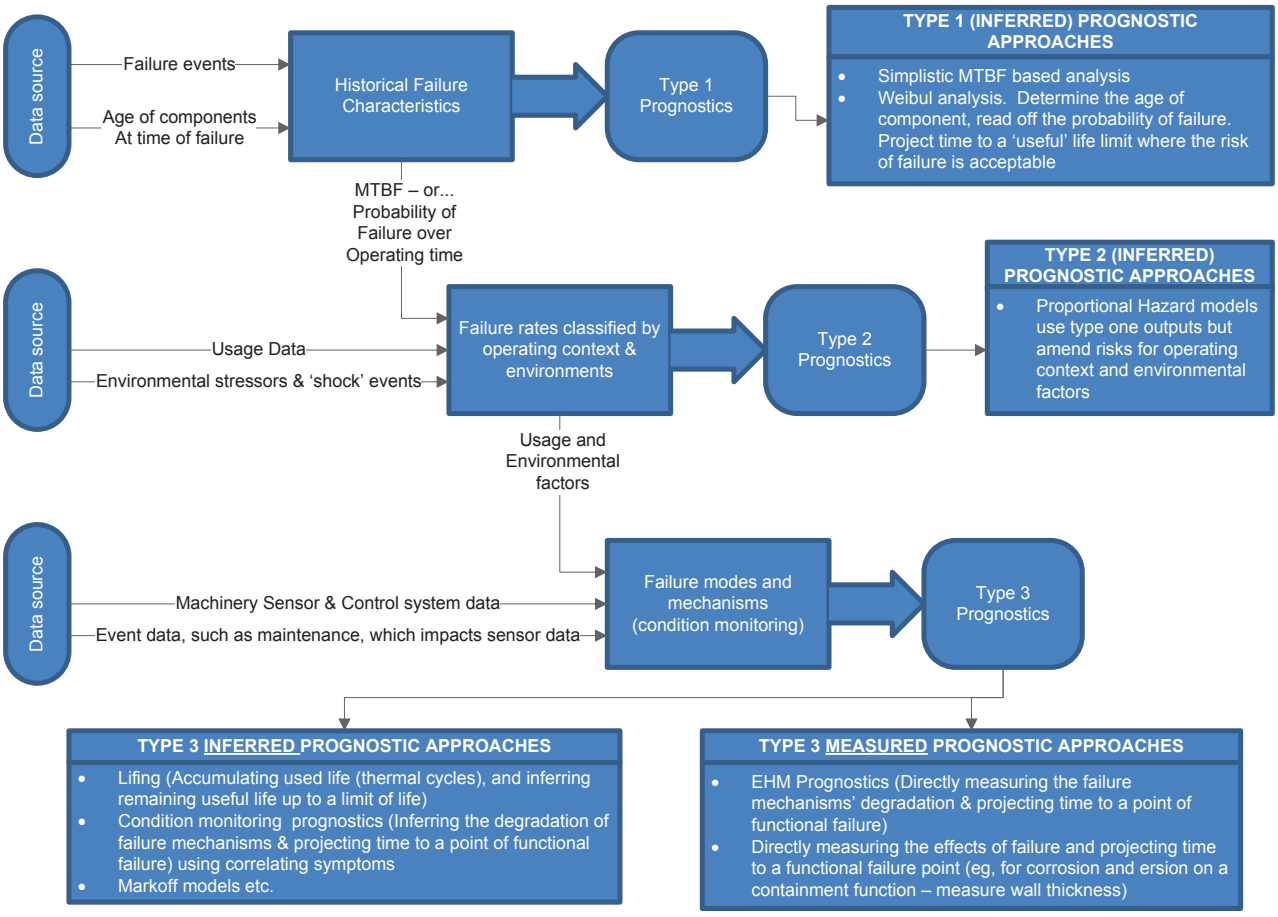


Figure F.3—Prognostics Classification Approaches

NOTE ISO 13381-1 [39] may be useful to the operator in understanding and implementing this technology.

F.2.2 Failure Mode Specific Models

Each failure mode may require its own prognostic model as mentioned in F.1.4.

Garvey and Hines have classified prognostic models into three types as outlined below [40].

F.2.3 Type I—Traditional Reliability Analysis

This class of models uses parametric and nonparametric models to estimate failure density functions. These models assume that past usage and degradation will be indicative of future conditions. Hazard rates are assumed to follow the bathtub curve shown in Figure F.4, which describes a decreasing, constant, and increasing failure rate corresponding to infant mortality, random failure, and equipment wear-out. The most widely used model for describing the failure distribution over time is the Weibull distribution. The Weibull distribution is very flexible and by varying the parameters of the distribution a good approximation of the bathtub curve can be achieved. A rigorous discussion of the application of the Weibull can be found in *The New Weibull Handbook* [41].

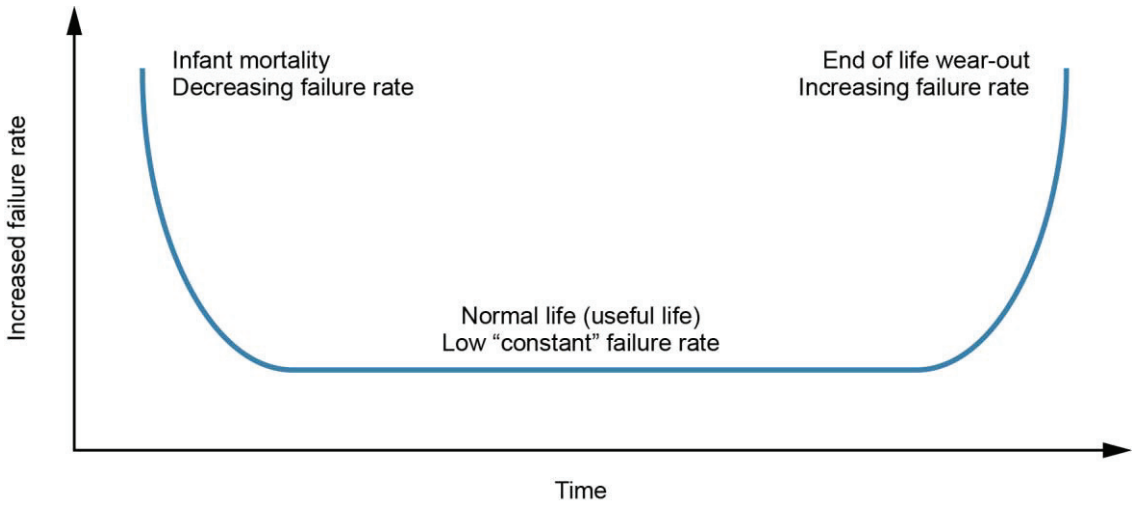


Figure F.4—Bathtub Curve

F.2.4 Type II—Stress Based

A distinguishing characteristic for this class of prognostic models is the consideration of operating conditions such as operational load and/or environmental conditions and the impact of these elements on the system or component being modeled. This is important because the degradation rate of the equipment may vary based on these conditions. These models provide a RUL of the average equipment under review for a given set of operating conditions. Type II models include PHMs and MCMs. PHM was introduced by Cox and is a technique that combines failure data and stress data. The model may use a baseline hazard rate with a covariate multiplicative factor that yields a new hazard rate.

Markov chain modeling is a process that consists of a finite number of states with some known probabilities to move from one state to another (the transition probability). This process is independent of all previous states, and only the current state has any bearing on the transition probabilities.

MCMs are discrete in the time domain and degradation measure domain and provide a mechanism to account for equipment damage. This damage degradation is represented in units of damage and the probability of damage occurring. This is related to the operating conditions, environmental conditions, and the duty cycle load. The model is formulated as a probabilistic simulation of past and future degradation. At each step in time, specific parameters can be estimated from historical data:

a) probability of damage (degradation) in a duty cycle,

b) the amount or magnitude of the damage,

c) the POF at the current degradation level,

d) other factors such as the probability that personnel will find and repair the degradation before failure can be considered.

Some additional examples of physical stress-based models include:

a) Paris' law of crack growth modeling,

b) Forman's equation of crack growth modeling,

c) fatigue spall initiation and progression model,

d) contact analysis for bearing prognostics,

e) stiffness-based damage rule model.

F.2.5 Type III—Condition Based

F.2.5.1 General

This class of prognostic models is more advanced and uses measurements such as equipment parameters, process data, system health data, etc., directly from the operating system to develop the RUL for the components being modeled. The degradation measure can be a function of several variables measured directly or as an empirical model. These models develop cumulative damage based on the number of duty cycles the damage accumulates and grows toward the failure threshold. Cumulative damage models were proposed by Bogdanoff and Kozin [42].

F.2.5.2 General Path Model

The GPM developed by Lu and Meeker proposed that degradation measurements over time may contain useful information about reliability [43]. They developed statistical and nonlinear estimation methods for using degradation measures to estimate the time-to-failure distribution for degradation models and used Monte Carlo simulation (MCS) to estimate confidence intervals for reliability. GPM models have proven to very useful prognostic tools.

F.2.5.3 Incorporating Prior Information via Bayesian Methods

Bayes' theorem is most commonly expressed as:

$$P(A|B) = \frac{P(B|A)P(A)}{P(B)}$$

The learning process in Bayesian inference involved modifying the initial probability statements about parameters before observing the data or posterior knowledge that combines both prior knowledge and the data at hand; that is to say, the theorem links the degree of belief in a proposition before and after accounting for evidence. This evidence has already taken place and is known as priori information.

This information is used in prognostic models to obtain a posterior estimate of degradation parameters. This estimate then becomes known as the new prior distribution in the next estimate of the degradation parameters. The relative influence of the prior data on updated beliefs depends on how much weight is given to the prior based on the confidence that the data contains relevant information.

F.2.5.4 Data-driven Prognostic Models

The data-driven prognostic approach uses CM data directly to model RUL (refer to Figure F.2). These models are based on statistical and learning techniques related to pattern recognition. This approach can be problematic in that it relies on past data patterns for analysis and may use techniques such as exponential smoothing and autoregressive models [44]. Over time the patterns may change and new failure modes may introduce completely new data patterns. However, this approach is simple and where data patterns are consistent over time they can provide insight into RUL.

These models can be divided into two categories: statistical and artificial intelligence. Statistical approaches include multivariate analysis, principle component analysis, partial least squares, linear vector quantization, state space models, etc. Sikorska, Hodkiewicz, and Ma do an excellent job of classifying the modeling options for RUL estimation, and the reader is encouraged to review that material directly [45].

Annex G
(informative)

Guideline of API 691 Facility Audits

G.1 Introduction

This annex provides guidance on initiating and conducting API 691 audits for the purpose of ensuring safe and reliable machinery to the oil, gas, and petrochemical (OG&P) industry. This annex may be used as a guideline to qualifying vendors of API 691 Machinery. The recommended activities outlined are not intended to replace the vendor's or operator's program management, engineering, or QA/QC systems, but rather are meant to assist the operator in validating the vendor's capabilities in meeting the requirements of this recommended practice.

G.2 Triggers to Conducting Engineering and Inspection Audits

Operating companies have diverse strategies on when and how to conduct engineering and inspection audits. In some cases companies elect to simply defer to standards bodies such as ISO to ensure that adequate quality systems have been put in place, while others participate in the auditing process using multidisciplinary teams who review specific designs, manufacturing processes, and respective QA programs. Triggers that are typically used to initiate operating company audits within the industry include:

a) new manufacturing facilities for critical machinery,

b) new machinery technologies,

c) machinery with unproven components whose failure could lead to a loss of containment and/or a loss of functionality that could lead to a potential process safety event,

d) redesigns involving expanded operating envelopes,

e) facilities that have been bought out and/or been significantly restructured,

f) facilities that have manufactured machinery that have resulted in unacceptable HSE consequences (e.g. API 689, First Edition, Table C.1, Failure Consequence Classification Categories I–IX) and ISO 14224 [16],

g) time-based criteria (e.g. facility audit every 5 years),

h) dollar volume of machinery purchased,

i) risk assessments,

j) other.

API 691 facility audits are typically conducted after risk assessments have confirmed that the machinery or machinery technology is considered high risk by the operating company. The audits are most often conducted during the feasibility/concept selection, FEED, or detailed design phases.

G.3 Prior to Conducting API 691 Audits

G.3.1 Operating companies or their third-party representatives tasked with the responsibility of performing source audits for API 691 Machinery should develop a management program in order to provide the auditors guidance and information to accomplish their respective duties.

Where applicable depending on the machinery life cycle phase, the following information should be made available to the operator's auditing personnel prior to the scheduled audit:

a) completed API 691 Facility Audit Survey Form (see G.7),

b) experience list (reference list) and contact information,

c) comments and exceptions to the applicable API standard and operating company overlays,

d) DFMEA,

e) list of components subcomponents having TRL < 7 whose failure may lead to a loss of containment and/or a loss of functionality that could lead to a potential process safety event,

f) third-party qualification surveys, if available,

g) RAM data based on customer feedback, including failure rates (MTBF), failure mechanisms, etc.

h) summary of all engineering and manufacturing nonconformances over the last 5 years,

i) list of warranty claims over the last 5 years,

j) summary of any legal action taken by a third-party company resulting from HSE impacts,

k) documentation required by API 691 for the life cycle phase of concern (e.g. FEED).

G.3.2 The operator's representatives should review the details of the project or R&D plan, location of the vendor, and select the appropriate source engineers and inspector(s) for the assignment.

G.3.3 Safety of the individual(s) performing the API 691 audits is imperative. A safety program should be established that identifies specific safety hazards associated with the job. API 691 auditors should be adequately trained and knowledgeable in these safety programs in order to minimize the possibility of injury. The safety program should include:

a) potential travel safety issues specific to the job,

b) potential shop safety issues and hazard recognition,

c) how to handle the observation of unsafe acts in the shop.

G.3.4 The designated API 691 auditors should familiarize themselves with all project, design, manufacturing, etc. documents and ensure that they have access to the edition/version of those documents specified in the contractual agreement at all times during their visits. Prior to commencing the API 691 Machinery audit, the responsible individuals should confirm that the vendor has the most current documents, drawings, etc. specified in the engineering design. Later editions of industry codes and standards do not apply if the engineering design has specified an earlier edition of a specific standard. Additionally, the auditors should confirm that that all documents have been reviewed/approved by the operating company and/or by authorized vendor engineering and quality personnel.

G.3.5 Depending on the scope of the audit, it is sometimes necessary to sign nondisclosure agreements (NDAs) where highly confidential information is to be exchanged or viewed outside of the facility. The

operating company or manufacturing company should highlight requirements to ensure the appropriate sharing of proprietary information prior to a scheduled audit.

G.4 Feasibility and Concept Design Audits

G.4.1 Operating companies interested in developing concept designs prior to FEED will more often than not complete a TRC assessment report (refer to Annex A) without visiting a manufacturing facility. However, in cases where unproven (component or subcomponents with TRL < 7) technology is expected to be placed in high-risk services, the operating companies may elect to conduct a 691 facility audit to more accurately determine the vendor's likelihood of reaching acceptable levels of risk during the product development cycle and within the given time constraints of the project, program or funded R&D period. The focus of the audit will involve in-depth review of the vendor's product qualification program plan including any internal concept development, preliminary engineering, detailed design, and/or market ready stage gate reports.

G.4.2 The API 691 audit team should include the following information in the final audit report:

a) completed API 691 Facility Audit Survey Form (see G.7),

b) vendor risk analysis including internal criteria,

c) TRC assessment (if performed),

d) DFMEA,

e) product qualification program plan,

f) stage gate reports,

g) analysis, modeling, and calculations stemming from B.2 validation checks,

h) identification of areas of concerns, if any,

i) completed API 691 datasheet for feasibility and concept selection phase,

j) recommendations,

k) summary.

G.4.3 While photographs are commonplace in engineering and inspection reports as they assist in the description of observations, API 691 auditors should request permission prior to taking any photographs. Care should be exercised to ensure that an appropriate number of photos are attached as too many can be detrimental to report issuance due to file size. Photos should be dated and labeled with description of area of interest or product tag reference so that they can be easily understood.

G.4.4 The completed API 691 audit report will typically summarize its findings into one of the following categories.

a) Unconditional approval to invest in, pilot, or specify the machinery technology within the operating company.

b) Conditional approval based on the application of supplemental safeguards (e.g. physics of failure testing, additional analysis, scale model testing) that may need to be performed to reduce the levels of uncertainty of safe and reliable deployment.

c) Conditional approval based on the inclusion of recommended design changes (e.g. advanced CM, metallurgical or sealing upgrades, limited service applications) that would be expected to reduce the risk of operation in the field.

d) Conditional approval based on implementation of improved manufacturing or inspection processes.

e) Disapproval highlighting the technical challenges, obstacles, or problems that discourage investment or prevent the safe piloting of the proposed machinery technology at any time in the foreseeable future.

G.5 FEED Audits

G.5.1 Operating companies may elect to conduct FEED audits for API 691 Machinery meeting any of the following conditions.

a) Machinery that may be manufactured at new locations.

b) Machinery that will likely be operating in more severe conditions (pressure, temperature, etc.) than currently demonstrated by the vendor.

c) Machinery having components or subcomponents with TRL< 7 whose failure may lead to loss of containment and/or a loss of functionality that could lead to a potential process safety event.

d) Machinery known to have higher than acceptable warranty claims.

e) Machinery known to have caused HSE incidents.

G.5.2 The API 691 audit team should include the following information in the final audit report:

a) completed API 691 Facility Audit Survey Form (see G.7),

b) vendor risk analysis including internal criteria,

c) TRC assessment (if performed),

d) DFMEA,

e) PFMEA (if jointly developed),

f) supplementary protective measures,

g) analysis, modeling, and calculations,

h) nonconformances,

i) completed API 691 datasheets for feasibility and concept selection and FEED phases,

j) recommendations,

k) summary.

NOTE 1 When deviations to the contractual agreement or its referenced specifications, drawings, codes, or standards are identified or when violations are identified to the vendor's own internal QA/QC requirements, the API 691 audit team should identify them as nonconformances.

NOTE 2 In general, past engineering or manufacturing nonconformances on file for pressure-containing components (seals, casings, etc.) should be thoughtfully reviewed and documented by the API 691 audit team. Failure of the vendor to provide adequate disposition of these should be noted within the audit report.

NOTE 3 Acceptable disposition of a nonconformance (as approved by the responsible engineer/SME) may include:

a) use as is,

b) rework/repair per original contractual documents or approved repair procedure,

c) scrap the equipment/component involved and start over.

NOTE 4 Once the disposition of the nonconformance has been agreed by all appropriate parties and implemented, the API 691 audit team should find evidence that the past nonconformance report (NCR) was properly implemented.

G.5.3 The completed API 691 FEED audit report will typically summarize its findings into the categories noted in G.4.4 above.

G.6 Detailed Design Audits

G.6.1 Operating companies may elect to conduct API 691 audits during the detailed design phase to:

a) confirm the vendor's qualification in accordance with B.4,

b) determine the suitability of the vendor's project design team by ensuring that adequate experience and skill sets exist,

c) identify shortcomings in the vendor's standard design and manufacturing practices,

d) evaluate the risks associated with loss-of-containment failure mechanisms,

e) mutually develop PFMEA for the given operating conditions,

f) establish IOWs and SOLs,

g) evaluate the vendor's ability to provide field training for operating and maintenance personnel,

h) evaluate the capabilities of the vendor in repairing and providing rapid response to critical failures.

G.6.2 The API 691 audit team should include the following information in the final audit report:

a) completed API 691 Facility Audit Survey Form (see G.7),

b) vendor risk analysis including internal criteria,

c) results of the TRC assessment (if performed),

d) DFMEA,

e) PFMEA (if jointly developed),

f) IOWs and SOLs,

g) supplementary protective measures,

h) analysis, modeling, and calculations,

i) nonconformances,

j) field training capabilities,

k) completed API 691 datasheets for feasibility and concept selection, FEED, and detailed design phases,

l) recommendations,

m) summary.

G.6.3 The completed API 691 detailed design audit report will typically summarize its findings into the categories noted in G.4.4 above.

G.7 API 691 Facility Audit Survey Form

General Information (attach separate sheets as necessary)

Name of Company:	Parent Company Name:
Registered Address:	Street Address:
President/CEO:	
Manufacturing/Operations Manager:	Reports To:
Engineering Manager:	Reports To:
Quality Assurance Manager:	Reports To:
Contact Name/Title:	
Contact Telephone:	Contact Fax: E-Mail:
Contact Street Address:	
Alternate/After Hours Contact Name/Title:	
Alternate/After Hours Contact Telephone:	Alternate Contact Fax:
Alternate Contact Address:	
Recent (Within 1 year) Management Changes:	
Company Mission/Vision:	

Primary Products or Principal Specialty of Shop

Product/Specialty	Main Characteristics	Annual Dollar Volume

Number of Full-time Employees

Function	Contract	Noncontract
Administration:		
Manufacturing:		
Inspection/Testing:		
Field Service:		

Function	Contract	Noncontract
Engineering:		
Quality Assistance:		
Purchasing:		

Labor Management

Open Shop: Yes [ ] No [ ]	Union Shop: Yes [ ] No [ ]
Affiliation:	Contract Expires:
Shifts Available for Repair Work:	

Code/Standards Experience
(Explain specifically which codes and standards your facility has experience with.)

AWS:	ANSI:	SSPC:
ASME: Type of PV Stamp:	API:	AGMA:
NACE:	ASTM:	Other:
Other:	Other:	Other:

Analytical Capabilities

Design Capability	Name of Computer Program	Version	Define In-house Capability or Name of Qualified Subvendor
Computer Aided Design			
Aerodynamic/Thermodynamic Analysis			
Gear Design			
Finite Element Analysis			
Rotordynamic Analysis			
Stress Analysis			
Vibration Analysis			
Computational Fluids Analysis			
Other:			

Manufacturing Facility and Capabilities

Road Limitations (weight, height, or width) to Repair Facility from Nearest Interstate Highway:				
Bldg. Bay:	Width (feet):	Length (feet):	Crane Capacity:	Hook Height (feet):
Bldg. Bay:	Width (feet):	Length (feet):	Crane Capacity:	Hook Height (feet):
Bldg. Bay:	Width (feet):	Length (feet):	Crane Capacity:	Hook Height (feet):
Climate Control: Yes [ ] No [ ] (describe):				
Spreader Bar: Yes [ ] No [ ] Capacity (lb):				

Manufacturing Facility and Capabilities (Continued)

Welding Processes	List Current Welding Procedures (WQRs) and Availability for Review	List Current Welder Qualification Records (WQRs) and Availability for Review
Plasma arc welding (PAW)		
Gas metal arc welding (GMAW) or (GMAW-P)		
Gas tungsten arc welding (GTAW) or (GTAW-P)		
Shielded metal arc welding (SMAW)		
Submerged arc welding (SAW)		
Flux cored arc welding (FCAW)		
Other Welding Processes	**Written Procedures**	**Qualified Operators**
Torch Brazing (TB)	Yes [ ] No [ ]	Yes [ ] No [ ]
Induction Brazing (IB)	Yes [ ] No [ ]	Yes [ ] No [ ]
Furnace Brazing (FB)	Yes [ ] No [ ]	Yes [ ] No [ ]
Other Brazing (Specify)	Yes [ ] No [ ]	Yes [ ] No [ ]
Oxyacetylene Welding (OAW)	Yes [ ] No [ ]	Yes [ ] No [ ]
Other:		

Welding Processes	List Current Welding Procedures (WQRs) and Availability for Review	List Current Welder Qualification Records (WQRs) and Availability for Review
Cutting Processes	**Written Procedures**	**Qualified Operators**
Oxyfuel Gas Cutting (OFC)	Yes [ ] No [ ]	Yes [ ] No [ ]
Plasma Arc Cutting (PAC)	Yes [ ] No [ ]	Yes [ ] No [ ]
Air Carbon Arc Cutting (AAC)	Yes [ ] No [ ]	Yes [ ] No [ ]
Other:		
AWS Certified Welding Inspector On-site	Yes [ ] No [ ]	Yes [ ] No [ ]
Are Welding Rods/Wire Stored in Climate Controlled Storage Area?	Yes [ ] No [ ]	Yes [ ] No [ ]
Thermal Spraying Processes	**Written Procedures**	**Qualified Operators**
Electric Arc Spraying (EASP)	Yes [ ] No [ ]	Yes [ ] No [ ]
Plasma Spray (PSP)	Yes [ ] No [ ]	Yes [ ] No [ ]
High Velocity Spraying (HVOF) [ ] (HVLF) [ ]	Yes [ ] No [ ]	Yes [ ] No [ ]
High Velocity Intermittent Combustion (HVIC)	Yes [ ] No [ ]	Yes [ ] No [ ]
Flame Spraying (FLSP)	Yes [ ] No [ ]	Yes [ ] No [ ]
Other	**Written Procedures**	**Qualified Operators**
Plating	Yes [ ] No [ ]	Yes [ ] No [ ]
Babbitt	Yes [ ] No [ ]	Yes [ ] No [ ]

Manufacturing Equipment (Attach list if more convenient.)

Equipment Type	Description (capacity/size/weight)	Capabilities/ Accuracy	Last Calibration Date (if applicable)
Lathes			
Grinders			
Cylindrical			
Surface			
ID			
Multi-purpose Machining Centers			
Milling Machines			
Vertical Boring Mill			
Horizontal Boring Mill			

Equipment Type	Description (capacity/size/weight)	Capabilities/ Accuracy	Last Calibration Date (if applicable)
Gear Cutters			
Shapers			
Hobbers			
Milling Cutter			
Gear Finishing			
Shaving			
Grinding			
Lapping			
EDM (Electrical Discharge Machining) Capability			
Special-purpose Tooling			
Lapping			
Honing			
Automated Peening			
Spline Machine			
Bucket Machines			
Thread Rolling			
Curvic Coupling Grinder			

Equipment Type	Description (capacity/size/weight)	Capabilities/ Accuracy	Last Calibration Date (if applicable)
Balance Machines At Speed: Yes [ ] No [ ]	Drive: Belt [ ] End [ ]	Max. Rotor Weight:	Min. Rotor Weight:
Bearing: Hard [ ] Soft [ ]		Maximum Sensitivity per Plane (in.-oz)	
Balance Machines At Speed: Yes [ ] No [ ]	Drive: Belt [ ] End [ ]	Max. Rotor Weight:	Min. Rotor Weight:
Bearing: Hard [ ] Soft [ ]		Maximum Sensitivity per Plane (in.-oz)	
Rotor Assembly/Disassembly Pit		Max. Rotor Weight:	Maximum Distance Between Journals:
Vee Block Rotor Runout Stand			
Overspeed Pit for Impellers			

List All Manufacturing, Testing, and Repair Work Being Subcontracted (such as welding, heat treating, lab testing, balancing, coating, deposit analysis, etc.)

Type Operation	%	Length of Affiliation	Name and Address of Subcontractor

Heat Treat Capabilities

Describe: Oven size, temperature range, control system, recording capabilities, resistance blankets, induction heating, etc.

_____

_____

_____

_____

Oven available to heat components for assembly Yes [ ] No [ ]

Largest Component Size/Weight:

Examination (nondestructive)

Type	In-house or Contract	Standard Utilized/Number and Level of Trained Employees	List Written Procedures/ Acceptance Criteria
Ultrasound			
Eddy Current			
Radiographic			
Wet Magnetic Particle			
Intermittent			
Continuous			
Liquid Penetrant			
Post-emulsifiable Fluorescent			
Solvent Removable Fluorescent			
Water Washable Fluorescent			
Post-emulsifiable Visible Dye			
Solvent Removable Visible Dye			
Water Washable			

Type	In-house or Contract	Standard Utilized/Number and Level of Trained Employees	List Written Procedures/ Acceptance Criteria
Visible Dye			
Plot Electrical and Mechanical Runout			
Hall Effect Gauss Meter			
3D Coordinate Measuring			
Gear Checking Machine			
Overspeed Trip Set			
Material Analyzer			
Hardness Testing			
SEM (Scanning Electron Microscope)			
Optical Comparator			
Metallography			
Screw Rotor Mesh Check			
Surface Roughness			
Other:			
Other:			
Other:			

Cleaning/Coatings

Decontamination Facilities	Yes [ ] No [ ]	
Steam Cleaning	Yes [ ] No [ ]	
High-pressure Water Wash	Yes [ ] No [ ]	
Abrasive Blasting Booth	Largest Component (L × W × H):	
Solvent Cleaning	Largest Component (L × W × H):	
Other:		
Erosion Coating System:	Describe:	
Corrosion Coating System:	Describe:	

	Yes	No	Explain
Management of the Quality System			
Has the top management stated and communicated a corporate quality policy?			
Are full-time resources devoted to the quality system other than manufacturing quality control?			
Is a system in place to measure cost of nonconformance for the business unit?			
Is there a continuous improvement program and do you track long-term trends and cost of nonconformance?			
Marketing Quality Assurance			
Does marketing/sales have a documented process to communicate customer requirements to the repair facility?			
Does marketing/sales process assure, compliance to customer requirements from the repair facility before technical and commercial commitments are made?			
Do you have a system/process to accurately transfer customer driven change orders from marketing/sales to the repair facility after an order?			
Is there a documented process in place for prompt communication between the repair facility and customer if nonconforming products/materials/delivery is discovered or suspected?			
Project Management Assurance			
Do you have a project management function that has total order responsibility including schedules, cost control, documentation, and internal and external communication?			
Do project managers have experience with similar type of equipment?			
Does the same project manager follow the equipment through to installation and start-up if requested by owner?			
Are all repairs assigned to a project manager?			

	Yes	No	Explain
Design Engineering Quality Assurance			
Do you have documented procedures for translation of customer specifications into internal company language?			
Describe the formal design review process. Include the following:			
1. When design reviews are held.			
2. What functional areas are involved			
3. What design verification activities are used			
Is there a formal design review?			
Are design changes coordinated with the owner?			
Does a revised drawing and document procedure exist to assure that appropriate personnel are receiving current drawings and documents?			
Describe how changes result in revised procedures, drawings, travelers, etc. and how these changes are distributed to the appropriate personnel in a timely manner.			
Are obsolete drawings and specifications in production and inspection withdrawn from use?			
Is there an in-house engineering/technical support staff?			
Can failure analysis be done in-house?			
Vendor (Procurement) Quality Assurance			
Do you have a process for managing the quality of purchased goods and services?			
Are required references (drawings and specifications, special process control and inspection/test requirements) given to the vendor with the purchase order?			
Are purchase order requirements available to receiving personnel to ensure correct material is received and any special instructions are followed?			

	Yes	No	Explain
Is evidence of material and product inspection/tests documented on appropriate records?			
Is appropriate segregation provided for raw, nonconforming, and accepted material pending inspection and/or test?			
Is there a process for control of nonconformance to assure effective vendor corrective action?			
Do you have and maintain an approved/acceptable vendor's list?			
Is there a plan that provides for effective control and appraisal of characteristics that cannot be inspected upon arrival (e.g. nondestructive testing, heat treat, chemical analysis)?			
Is there a plan that assures vendor's special processes (heat treating, welding, etc.) are currently qualified?			
Is manufacturing equipment calibrated/maintained at established intervals?			
Manufacturing/Production Quality Assurance			
Is there a quality control program with a working manual and revision procedures?			
Are process instructions, procedure sheets, travelers, etc. utilized that contain requirements for manufacturing and inspection control?			
Are operator's and inspector's identification applied to documentation as required?			
Is the status of lots and/or items shown on tags, routing cards, move tickets, totebox cards, etc.?			
Are nonconforming items removed from normal channels and placed in appropriate isolation areas?			
Is rework conducted with authorized and documented procedures and subject to inspection/test?			

	Yes	No	Explain
Are corrective action forms and procedures utilized to prevent and/or control recurrence of defects as appropriate?			
Does the final inspection and testing acceptance include verification of any in-process inspection and testing?			
Are inspection records completed and include (as appropriate) part and lot control number, customer, engineering changes, lot and sample size, characteristics inspected, quantity, etc.?			
Do items or materials released for manufacturing contain appropriate documentation of inspection/test performance?			
Are personnel and/or equipment certifications conducted in conformance with applicable requirements?			
Are examination and equipment test and control records current and available for review?			
Are maintenance checks of equipment conducted and records maintained to verify status?			
Material Storage Area, Packing, and Shipping Quality Assurance			
Is acceptance for storage and release of material based on correct identification and authorized release by appropriate function?			
Do documented storage practices include control for correct location in area/bin/shelf per record; and adequate segregation and protection to prevent damage, intermingling and corrosion, and age sensitive material?			
Is there a process to ensure required enclosures and protection procedures are utilized before shipment?			
Do the procedures ensure product identification and protection during transient storage and installation?			
Measuring and Testing Equipment Quality Assurance			
Do records verify calibration and traceability			

	Yes	No	Explain
to appropriate standards?			
Is test and measurement equipment calibrated within established intervals?			
Are items labeled, tagged, or otherwise identified as required to reflect serviceability date and date of next calibration?			
Do calibration records contain information required for controlling scheduling frequency?			
Is unqualified equipment identified to show its status and prevent its use?			
Are handling practices of test and measuring equipment available and properly maintained?			
Field Quality Assurance			
Do you have a system that gathers and monitors data on product field history?			
Is there a corrective action system and are problems defined by this system assigned to a responsible party for corrective action?			
Do you have a field notification system that makes users of equipment aware of product enhancements or upgrades that could be used to improve the performance of existing equipment?			
Quality Records System			
Are quality records protected and stored for a specified period of time in a fashion that allows retrieval of specific data?			
Human Resource Development and Training			
Do you have a means of identifying the need for training of all personnel?			
Do you have a training program for all personnel?			
Are all personnel given formal training in how their job performance influences product quality and customer satisfaction?			
Do you have a journeyman program for crafts personnel?			

	Yes	No	Explain
Product Safety			
Do you have a process that addresses the safety aspects of the product or service?			
Does this process include provisions for product recall?			

Competitiveness

I. Describe the process and/or methods used to improve your company's cost competitiveness position. (One page maximum.)

II. Do you measure Cost of Quality? _____ Y/N _____

III. Would you be willing to let your competitors visit your shop in order that they may also quote on the same repair? _____

Facilities/Expenditures:

Average annual capital expenditures: amount _____ % of sales _____

Average annual maintenance costs: amount _____ % of sales _____

% of replacement value: _____

How long have you been repairing this type of equipment? _____

Does this facility have a safety program/policy? _____

Does this facility have an environmental program/policy?

_____

Would you allow a shop inspection by the owner or a third party hired by the owner?

_____

Service Performance

	Yes	No
A. Electronic data transfer with vendor is possible?	_____	_____
B. Photographic records provided?	_____	_____
C. Field service is available within 24 hours?	_____	_____
D. Vendor has appropriate product liability insurance?	_____	_____
Elaborate:		
E. Do you have a warranty agreement on repairs?	_____	_____
Submit a copy.		
F. Can you arrange safe transport of equipment to and from jobsite?	_____	_____
G. Can you arrange for transportation insurance?	_____	_____

Customer Service

Do you regularly monitor on time deliveries to customer request date? If yes, what percentage of your deliveries are on time?

Quality System Registration

Indicate whether or not your Quality Assurance system is currently registered under ISO or ANSI/ASQC:

_____ 9001 _____ 9002 _____ 9003 _____ Other

(enclose a copy registration certificate, if available)

	Yes	No
Does your QA system conform to API Q1?	_____	_____

Business Information

Number of years in business under the present name? _____

Previous names: (please list) _____

Type of ownership (partnership/corporation, joint venture, other) _____

Publicity traded: _____ Privately held: _____

Sales volume past three years: $_____ $_____ $_____

Current backlog $_____

Dunn and Bradstreet or other (name) rating: _____

Do you have Liability Insurance? Yes _____ No _____ Amount/Incident _____

Can you provide a copy of annual report? If so, please enclose. If not, what type of financial reports will you provide? Please enclose.

Vendor/Owner Relationship

Have you sold any product to the owner in the past three years?

Yes _____ No _____

If yes,

Purchase Order Number	Delivery Location	Description of Work

References

Company/Contact/Location	Telephone	Description of Repair Work Performed

List Any Other Information About Your Company That You Think Is Relevant

(include recent management changes, shop turnover in key positions, current legal involvements, associations with other repair shops or equipment vendors, etc.)

Could You Prepare Written Objective Evidence to Verify Responses Given on This Questionnaire, in 30 Days or Less, If Required?

_____ Yes _____ No

Verification by Responsible Parties

_____ _____

Vendor Technical Representative/Title/Date Vendor Management Representative/Date

_____

Owner's Representative/Title/Date
(required for on-site verification only)

Annex H
(informative)

Datasheets

energy API			JOB NO.					Revision
			ITEM NO.					
RISK-BASED MACHINERY MANAGEMENT			PURCHASE ORDER NO.					
API 691 ANNEX H.1			SPECIFICATION NO.					
EQUIPMENT DATASHEET			REVISION NO.			DATE		
FEASIBILITY AND CONCEPT SELECTION			PAGE	1	OF 2	BY		

FOR			VENDOR	
SITE			MODEL	
UNIT			SERIAL NUMBER	
SERVICE	☐	CONTINUOUS	TAG NO.	
	☐	INTERMITTENT	P&ID SHEET NO.	
	☐	STANDBY	NO. REQUIRED	

NOTE: INFORMATION TO BE COMPLETED: ◯ BY OPERATING COMPANY (OC) ☐ BY VENDOR (V) △ BY DRP
◯ BY VENDOR IF NOT BY OPERATING COMPANY △ BY DRP IF NOT BY OPERATING COMPANY

TECHNICAL RISK CATEGORIZATION

◯ RISK ASSESSMENT APPROACH

NOTE: Mark the approach used. If company criteria are used, they should be appended to the DATASHEET

☐ COMPANY INTERNAL CRITERIA

☐ API 691TECHNICAL RISK CATEGORIZATION (ANNEX A.2.4.6)

◯ OVERALL TECHNICAL RISK CATEGORY (4.2, ANNEX A.2.4.6)

NOTE: Mark the overall rating. Remarks can be used to further comment on the risk assessment

A - Very High	☐
B - High	☐
C - Medium	☐
D - Low	☐

REMARKS:

◯ DETAILED TECHNICAL RISK CATEGORIZATION (4.2, ANNEX A.2.4.6)

NOTE: Mark the individual scores that formed the basis for the overall rating. Remarks can be used to further comment on the risk assessment

CATEGORY	RELIABILITY	CONFIGURATION	ENVIRONMENT	ORGANIZATION
A - Very High	☐	☐	☐	☐
B - High	☐	☐	☐	☐
C - Medium	☐	☐	☐	☐
D - Low	☐	☐	☐	☐

TECHNOLOGY READINESS LEVEL (TRL)

☐ HIGHER RISK COMPONENTS AND SUBCOMPONENTS HAVING A TRL <7 WHOSE FAILURE MAY LEAD TO LOSS OF CONTAINMENT AND/OR A LOSS OF FUNCTIONALITY LEADING POTENTIALLY TO A PROCESS SAFETY EVENT (4.3.2)

TRL	COMPONENT OR SUBCOMPONENT	TRL	COMPONENT OR SUBCOMPONENT

NOTE: TRL levels are defined below and explained in Table 1. Remarks can be used to further comment on the risk assessment

TRL	DEVELOPMENT STAGE
0	Unproven Concept
1	Proven Concept
2	Validated Concept
3	Prototype Tested
4	Environment Tested
5	System tested
6	System Installed
7	Field Proven

REMARKS:

energy API	JOB NO.						Revision
	ITEM NO.						
RISK-BASED MACHINERY MANAGEMENT	PURCHASE ORDER NO.						
API 691 ANNEX H.1	SPECIFICATION NO.						
EQUIPMENT DATASHEET	REVISION NO.				DATE		
FEASIBILITY AND CONCEPT SELECTION	PAGE	2	OF	2	BY		

ADDITIONAL REQUIREMENTS

○ ADDITIONAL REQUIREMENTS

NOTE: Mark the relevant items below that should be addressed by the Responsible party as indicated. Items that are checked by default indicate Normative requirements

☑	MACHINERY R&D PRODUCT QUALIFICATION PROGRAM FOR HIGH RISK COMPONENTS (4.4.1)
☑	ANALYTICAL VALIDATION OF COMPONENTS AND SUBCOMPONENTS (4.4.10.1)
☐	DESIGN VALIDATION WITHIN EXPECTED OPERATING ENVELOPE (4.4.10.3, ANNEX B.2)
☐	FUNCTIONAL PERFORMANCE TESTING (4.4.11)
☐	FIELD PILOT TESTING (4.4.11.3)

REFERENCE DOCUMENTATION

○ INCLUDED DOCUMENTS (9.2)

NOTE: Mark the required documents that shall be retained – record copy or maintained "as operating". Include additional key documents in the blank cells

REQUIRED	DOCUMENT	REV. #	DOCUMENT NUMBER
☑	Technical Risk Categorization Assessment Report (V or OC, 4.2.2)		
☑	Summary of Components or Sub-components with TRL<7 Whose Failure May Lead to a Loss of Containment and/or a Loss of Functionality Leading Potentially to a Process Safety Event (V, 4.3.2)		
☑	Product Qualification Program Guide (V, 4.4.1)		
☐	API 691 datasheets - Annex H (OC, 4.2.2; V, 4.3.2)		
☐	Concept Development Stage Gate Report (V, 4.4.5)		
☐	Preliminary Engineering Stage Gate Report (V, 4.4.6)		
☐	Detail Engineering Stage Gate Report (V, 4.4.7)		
☐	Product Release Approval Stage Gate Report (V, 4.4.8)		
☐	Design Validation Report for Specific Operating Envelope (V&OC, 4.4.10.3)		
☐	Facility Audit Report in Accordance With Annex G (OC, 4.5)		
☐			
☐			
☐			
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REMARKS AND/OR SPECIAL REQUIREMENTS

energy API

RISK-BASED MACHINERY MANAGEMENT
API 691 ANNEX H.2
EQUIPMENT DATASHEET
FRONT-END ENGINEERING DESIGN (FEED)

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FOR			VENDOR	
SITE			MODEL	
UNIT			SERIAL NUMBER	
SERVICE	☐	CONTINUOUS	TAG NO.	
	☐	INTERMITTENT	P&ID SHEET NO.	
	☐	STANDBY	NO. REQUIRED	

NOTE: INFORMATION TO BE COMPLETED: ◯ BY OPERATING COMPANY (OC) ☐ BY VENDOR (V) △ BY DRP
☐ BY VENDOR IF NOT BY OPERATING COMPANY △ BY DRP IF NOT BY OPERATING COMPANY

INITIAL MACHINERY RISK SCREENING CRITERIA (H.4.2)

△ ☐ HAZARDOUS GAS OR LIQUID SERVICES AS DEFINED BY JURISDICTION, APPROPRIATE REGULATORY BODY AND/OR OPERATING COMPANY STANDARDS OR SPECIFICATIONS

△ ☐ SERVICES OPERATING AT TEMPERATURES > 350°F (177°C) AND HAVING DESIGN OR SPECIFIED OFF DESIGN OPERATING PRESSURES > 80% MAWP

△ ☐ SERVICES OPERATING AT TEMPERATURES > 400°F (204°C)

☐ ☐ COMPONENTS AND SUBCOMPONENTS HAVING TECHNOLOGY READINESS LEVELS (TRL) < 7 WHOSE FAILURE MAY LEAD TO A LOSS OF CONTAINMENT AND/OR A LOSS OF FUNCTIONALITY THAT COULD LEAD TO A POTENTIAL PROCESS SAFETY EVENT (SEE TABLE 1)

△ ☐ LIQUID SERVICES OPERATING AT PRESSURES IN EXCESS OF 600 PSIG (41.4 BAR)

△ ☐ LIQUID SERVICES HAVING SPECIFIC GRAVITIES LESS THAN 0.5

△ ☐ OTHER, PLEASE SPECIFY

REMARKS:

PRELIMINARY RISK ASSESSMENT

△ PROCESS LEVEL RISK ASSESSMENT APPROACH (5.2.2)

☐ HAZOP ☐ COF ASSESSMENT ☐ POF / COF ASSESSMENT ☐ OTHER, PLEASE SPECIFY

REMARKS:

△ MACHINERY RISK ASSESSMENT APPROACH (5.2.3)

☑ PFMEA ☐ COF ASSESSMENT ☐ POF / COF ASSESSMENT ☐ LOPA ☐ OTHER, PLEASE SPECIFY

REMARKS:

△ RISK CONSEQUENCE CATEGORIES CONSIDERED

☑ SAFETY ☑ ENVIRONMENTAL ☐ ASSET / PRODUCTION / FINANCIAL ☐ OTHER, PLEASE SPECIFY IN REMARKS

REMARKS:

△ APPLICABLE RISK MATRIX

☐ COMPANY RISK MATRIX - ATTACH COPY, INCLUDING RELEVANT DEFINITIONS ☐ API 691 RISK MATRIX (ANNEX A.2.4.6)

NOTE: When API 691 Risk Matrix is selected, Probability of Failure (POF) and Consequence of Failure (COF) definitions from Figure A.2 should be used

NOTE: If alternative definitions are used, they should be included as an attachment to the datasheet

PROBABILITY OF FAILURE	1 Negligible	2 Minor	3 Significant	4 Major	5 Catastrophic
5 Almost Certain	Med	Med	High	High	High
4 Probable	Med	Med	Med	High	High
3 Possible	Low	Med	Med	Med	High
2 Unlikely	Low	Low	Med	Med	Med
1 Rare	Low	Low	Low	Med	Med

CONSEQUENCE OF FAILURE

NOTE: 3 Risk Levels should be defined:
Red = High or Unacceptable
Yellow = Medium or Tolerable
Green = Low or Acceptable

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PRELIMINARY RISK ASSESSMENT - OVERALL RATING (5.2, ANNEX A.2.4)

NOTE: Mark the overall rating for the preliminary risk assessment rating within the equipment boundary.

☐ HIGH ☐ Med ☐ Low

REMARKS:

PRELIMINARY RISK RANKING - EQUIPMENT LEVEL (5.2.3.1-e)

NOTE: Mark the top (highest risk) individual hazards and/or failures that formed the basis for the overall rating within the equipment boundary

ID	RISK LEVEL (H, M, L)	RISK TYPE (Safety, Env, Other)	HAZARD OR FAILURE DESCRIPTION
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			

SUPPLEMENTARY PROTECTIVE MEASURES (5.2.4)

NOTE: Mark all supplementary protective measures that are required to attain acceptable risk from loss of containment and/or a loss of functionality leading potentially to a process safety event.

NOTE: Mark 'Related Risk IDs' from previous table that credit each supplemental protective measure

ID	SUPPLEMENTARY PROTECTIVE MEASURE	RELATED RISK IDs
A		
B		
C		
D		
E		
F		
G		
H		
I		

RAM-1 ANALYSIS (5.3.2, Annex A.2.3.8)

RAM-1ANALYSIS REQUIRED

NOTE: Mark whether RAM-1Analysis is Required (Yes or No) ☐ YES ☐ NO

RAM-1ANALYSIS SCOPE

NOTE: Mark the RAM-1Analysis scope. ☐ PLANT LEVEL ☐ SYSTEM LEVEL ☐ PROCESS UNIT LEVEL ☐ EQUIPMENT LEVEL

RAM DATA SOURCES

NOTE: Mark the sources of data used in the RAM Analysis. Remarks can be used to provide additional explanation

☐ Internal CMMS historical data for similar or identical machinery

☐ Internal CMMS historical data for general equipment types

☐ OREDA ☐ OEM

☐ ORAP ☐ Other (Consultants)

REMARKS:

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FIELD OPERATIONAL AND PERFORMANCE TARGETS (5.1)

PERFORMANCE TARGET	VALUE	UNITS
Safety		
Health		
Environmental Emissions		ml/m3 (EPA Method 21)
Expected MTBF		Months
Expected MTTR		Days
Turnaround Frequency		Months
Expected Reliability		%
Expected Operational Availability		%
Extected Continuous Operation		Hours

OPTIONAL FIELD TESTING

☐	STEAM TURBINE SOLO RUN TEST (5.9.2)
☐	MOTOR SOLO RUN TEST (5.9.3)
☐	CENTRIFUGAL , AXIAL & SCREW COMPRESSOR INERT GAS TEST (5.9.4)
☐	RECIPROCATING COMPRESSOR INERT GAS TEST (5.9.5)
☐	FIELD PERFORMANCE TEST ON PROCESS GAS (5.9.6.1)

REFERENCE DOCUMENTATION

INCLUDED DOCUMENTS (9.3)

REQUIRED	DOCUMENT	REV. #	DOCUMENT NUMBER
☑	Required Documents from Feasibility & Concept Selection Phase		
☑	Machinery Risk Management System Program Guide (OC, 12.2)		
☑	HAZOP, PHAs or PSA Studies (OC or DRP, 5.2.2)		
☑	Preliminary Risk Assessment (OC or DRP, 5.2)		
☑	Summary of Secondary Protective Measures (OC or DRP, 5.2.4)		
☑	Summary of Components and Sub-components Having TRL <7 Whose Failure May Lead to Loss of Containment and/or a Loss of Functionality Leading Potentially to a Process Safety Event (V, 5.4.4)		
☑	DFMEA (V, 5.6)		
☑	Third-party Verification of Manufacturer's Compliance to API Q1/ISO 29001, ISO 9000, or equivalent		
☐	Operating, Maintenance and Facility Completion, Planning & Execution Deliverables (OC or DRP, 5.8)		
☐	API 691Datasheet -Annex H (OC, 5.2.3, NOTE 2)		
☐	RAM -1Analysis Report (OC or DRP, 5.3.2)		
☐	Facility Audit Report in Accordance with Annex G (OC or DRP, 5.7.5)		
☐			
☐			

REMARKS AND/OR SPECIAL REQUIREMENTS

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	☐	STANDBY		NO. REQUIRED					

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◯ BY VENDOR IF NOT BY OPERATING COMPANY △ BY DRP IF NOT BY OPERATING COMPANY

EQUIPMENT BOUNDARY

△ DEFINE EQUIPMENT BOUNDARY (ANNEX A.2.3)

NOTE: Mark In Scope elements of boundary definition for the equipment type. Remarks can be used to further comment on equipment boundary details

☐	Machinery Driver	Electric motor, turbine or engine
☐	Machinery Driven	Compressor, pump
☐	Power transmission	Gear box, coupling
☐	Machinery Controls	PLC, unit control panel
☐	Auxiliary Equipment	Equipment supporting machinery function such as lube oil pump, coolers, seal system, starter units.

☐	Process Equipment	Inlet scrubbers, discharge coolers and associated process equipment
☐	Process Controls	Process instruments controlling fluid conditions and machinery response
☐	Condition Monitoring	Instrument sensors and equipment used to monitor performance

REMARKS:

DETAILED MACHINERY RISK ASSESSMENT

△ RISK ASSESSMENT APPROACH (6.2.4, A.2.4)

☐ PROCESS FAILURE MODES AND EFFECTS ANALYSIS (PFMEA) ☐ FAULT TREE ANALYSIS
☐ LAYERS OF PROTECTION ANALYSIS (LOPA) ☐ OTHER, PLEASE SPECIFY

REMARKS:

△ UNMITIGATED HIGH RISK EQUIPMENT ITEMS (6.2.2, ANNEX A.2.4)

NOTE: Enter the risk analysis results below only for those failure mode, mechanism and cause combinations within the equipment boundary resulting in a HIGH risk rating

NOTE: The API 691 FMEA Worksheet may be used to conduct the detailed risk assessment (Annex I)

NOTE: The definition of HIGH risk should be based on the criteria established in FEED for preliminary risk assessment

ID	MAINTAINABLE ITEM	RISK TYPE (Safety, Env, Other)	FAILURE DESCRIPTION (FAILURE MODE / MECHANISM / CAUSE)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			

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RISK MITIGATING TASKS (6.4, ANNEXES D and E)

NOTE: Enter the risk mitigating tasks below and 'Related Risk IDs' from previous table that where the indicated task was considered in assessment of risk mitigation

NOTE: Task Types may include: **CM** - Condition Monitoring, **PM** - Preventive Maintenance, **FF** - Failure Finding

NOTE: For one-time tasks (e.g., design changes), a frequency of "ONCE" should be used. For tasks involving online data sampling, a frequency of "ONLINE" should be used

NOTE: Risk Mitigation task selection guidance and example templates is provided in Annex D. Guidance on condition monitoring and diagnostics is provided in Annex E.

ID	TASK TYPE	TASK DESCRIPTION	FREQUENCY	RELATED RISK IDs
A				
B				
C				
D				
E				
F				
G				
H				
I				
J				
K				
L				
M				
N				
O				

RAM-2 ANALYSIS (6.5, Annex A.2.4.9)

RAM-2 ANALYSIS REQUIRED

NOTE: Mark whether RAM-2 Analysis is Required (Yes or No) ☐ YES ☐ NO

RAM-2 ANALYSIS SCOPE

NOTE: Mark the RAM-2 Analysis scope. ☐ PLANT LEVEL ☐ SYSTEM LEVEL ☐ PROCESS UNIT LEVEL ☐ EQUIPMENT LEVEL

RAM-2 ANALYSIS DATA

NOTE: Provide information below for the highest risk failure events associated with the equipment boundary.

#	FAILURE EVENT (EQUIPMENT, FAILURE MODE)	FAILURE RATE	FAILURE DISTRIBUTION	REPAIR RATE	REPAIR DISTRIBUTION	PLANNED TURNAROUND FREQUENCY	PLANNED TURNAROUND DURATION
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							

NOTE: Remarks can be used to further comment on data sources used and assumptions

REMARKS:

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SAFE OPERATING LIMITS (6.6)

◯ SAFE OPERATING LIMITS (SOLs)

NOTE: Note the Manufacturer shall define all API691IOW Critical Limits. The Operator shall use this information to determine safe operating limits (SOLs)

NOTE: Note the SOLs for the API691required design basis elements design basis below. Additional SOL's should be added if applicable. Remarks can be used to further comment.

#	DESIGN BASIS ELEMENT	SOL VALUE
1	Maximum allowable vibration	
2	Maximum allowable suction pressure	
3	Minimum allowable suction pressure	
4	Maximum allowable casing pressure	
5	Maximum allowable inlet temperature	
6	Maximum allowable speed	
7	Minimum continuous stable flow	
8	Maximum allowable solids concentration	
9	Maximum allowable corrosive limits	
10	Maximum allowable bearing temperature	
11		
12		
13		
14		
15		
16		

REMARKS:

ADDITIONAL REQUIREMENTS

◯ ADDITIONAL REQUIREMENTS

NOTE: Mark the relevant items below that should be addressed by the Responsible party as indicated. Items that are checked by default indicate Normative requirements

◬	☑	OPERATIONS AND MAINTENANCE STRATEGY (6.2)
☐	☐	DESIGN FMEA FOCUSING ON FAILURE MODES ASSOCIATED WITH LOSS OF CONTAINMENT (6.3.1)
◬	☑	INTEGRITY OPERATING WINDOWS (IOWs) SPECIFICATION (6.6)
☐	☑	CONFIRMATION FOR COMPONENTS & SUBCOMPONEMTS TRL < 7 WHOSE FAILURE MAY LEAD TO A LOSS OF CONTAINMENT AND/OR A LOSS OF FUNCTIONALITY LEADING POTENTIALLY TO A PROCESS SAFETY EVENT (6.7.1)
◬	☑	MACHINERY SPECIFIC EQUIPMENT SERVICE CONDITION CHECKLIST VALIDATION REVIEWS (6.7.3, ANNEX B.4)
◬	☐	START-UP COMMISSIONING AND TEST PROCEDURES (6.8, 7.3.2)
◬	☐	CONTROL AND PROTECTION SYSTEM NARRATIVE WITH CAUSE AND EFFECT MATRIX (6.8.2)
◬	☑	MACHINERY STANDARD OPERATING PROCEDURES (6.9)

REMARKS AND/OR SPECIAL REQUIREMENTS

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REFERENCE DOCUMENTATION

◯ INCLUDED DOCUMENTS (9.4)

NOTE: Mark the required documents that should be retained – record copy or maintained " as operating". Include additional key documents in the blank cells

REQUIRED	DOCUMENT	REV.#	DOCUMENT NUMBER
☑	Required Documents From Earlier Life Cycle Phases		
☑	Detailed Machinery Risk Assessment (OC or DRP, 6.2)		
☑	Finalized P&IDs (OC or DRP, 6.2.3)		
☑	Finalized Equipment Datasheet (e.g. API 610 datasheet) (OC or DRP, 6.2.3)		
☑	Comments & Exceptions to API Standards (V, 6.2.3)		
☑	DFMEA (V, 6.3.2)		
☑	IOWs (V, 6.6.1)		
☑	SOLs (OC or DRP, 6.6.1)		
☑	Major Repair Procedures (V, 6.7.2)		
☑	Welder PQR (V, 6.7.3)		
☑	Commissioning Plan (OC or DRP, 6.8)		
☑	Finalized Cause and Effects Matrix (OC or DRP, 6.8.2)		
☑	SOPs (OC or DRP, 6.9)		
☑	Facilities Systems Completion, Planning & Execution Deliverables (OC or DRP, 6.10.1)		
☐	API 691 Datasheets - Annex H (OC or DRP, 6.4.1)		
☐	RAM-2 Analysis Report (OC or DRP, 6.5)		
☐	Facility Audit in Accordance With Annex G (OC or DRP, 6.7.4)		
☐			
☐			
☐			
☐			

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	☐	STANDBY	NO. REQUIRED		

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⬡ BY VENDOR IF NOT BY OPERATING COMPANY 🔔 BY DRP IF NOT BY OPERATING COMPANY

INSTALLATION (7.2.1)

◯ INSTALLATION PER API 686 STANDARD

NOTE: Mark whether Installation and Commissioning to be performed according to API 686 standard (Yes or No) ☐ YES ☐ NO

ASSURANCE CHECKLIST

◯ ASSURANCE CHECKLIST

NOTE: Mark whether the checklist items have been completed

COMPLETE	ID	ITEM
☐	1	Special risk mitigation steps identified in FEED and Detailed Design are reflected in the commissioning, test, start-up and operating procedures
☐	2	Commissioning/test plan includes verification of special risk mitigation design features identified in FEED and Detailed design
☐	3	Acceptance criteria for all test and commissioning activates is agreed to by operating company, start-up team and contractor
☐	4	Procedures for resolution of non-conformances in place
☐	5	Process in place for MOC and capturing changes to permanent plant records for changes triggered during commissioning and start-up
☐	6	PSSR (Pre-start-up Safety Review) Complete
☐	7	Emergency plans developed on issues and risks surrounding installation and commissioning
☐	8	Changes to the logic, set points, or control variables for machinery protective functions approved by manufacturer
☐	9	Unresolved risk items identified and entered into Management of Change (MOC) system
☐	10	All work processes (spare parts management, maintenance tasks, operator rounds etc.) finalized prior to initial start-up
☐	11	Baseline operating data was captured with the machine in the as-new condition to enable future condition monitoring
☐	12	Field performance test data permanently archived in a format to support future operation or risk assessment activities
☐	13	Incomplete compliance items documented and with assigned follow-up to the operating organization

ADDITIONAL REQUIREMENTS

◯ ADDITIONAL REQUIREMENTS

NOTE: Mark the relevant items below that should be addressed by the Responsible party as indicated. Items that are checked by default indicate Normative requirements

☐	COMMISSIONING PROCEDURES (7.3.2)
☐	FIELD FUNCTIONAL SAFETY TESTS (7.3.3)
☐	CONTROL AND PROTECTION SYSTEM FUNCTIONAL TEST PLAN (7.3.3.1)
☐	OPERATIONAL RUN TEST PROCEDURES (7.3.6.2)
☑	PRE-START UP SAFETY REVIEW (7.4)
☐	COMMISSIONING OPERATIONAL TEST - STEAM TURBINE SOLO RUN (7.5.2)
☐	COMMISSIONING OPERATIONAL TEST - MOTOR SOLO RUN (7.5.3)
☐	COMMISSIONING OPERATIONAL TEST - CENTRIFUGAL COMPRESSOR INERT GAS TEST (7.5.4)
☐	COMMISSIONING OPERATIONAL TEST - RECIPROCATING COMPRESSOR INERT GAS TEST (7.5.4)

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REFERENCE DOCUMENTATION

◯ INCLUDED DOCUMENTS (9.5)

NOTE: Mark the required documents that should be retained – record copy or maintained "as operating." Include additional key documents in the blank cells

REQUIRED	DOCUMENT	REV. #	DOCUMENT NUMBER
☑	Required Documents From Earlier Life Cycle Phases		
☑	Change Under the MOC process to Required Documents For Earlier Life Cycle Phases		
☑	Facilities Systems Completion, Planning & Execution Deliverables (OC or DRP, 7.1.2)		
☑	Functional Safety Test Reports (OC or DRP, 7.3.3)		
☑	Process Safety Valve Test Reports (OC or DRP, 7.3.4)		
☑	Operating & Maintenance Procedures (OC or DRP, 7.3.6)		
☑	PSSR Report (OC or DRP, 7.4)		
☐	API 686 Deliverables (OC or DRP, 7.2.1)		
☐	Optional Test Reports (OC or DRP, 7.5)		
☐			
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☐			

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FIELD RISK ASSESSMENT - KEY FINDINGS (8.2)

◯ ENTRY CRITERIA (8.2.5)

NOTE: Mark the relevant item(s) below that form the basis for the Field Risk Assessment

☐	Initial risk assessment for legacy machinery
☐	Newly installed API 691 Machinery
☐	Machinery affected by a risk relevant change and not assessed during the MOC process
☐	Machinery that has sustained moderate to severe safety failure consequences
☐	Machinery that has experienced a significant near miss with potential for severe failure consequences
☐	Machinery found to be operating outside of the safe operating limits (SOL) criteria.
☐	Machinery that has received Supplier Technical Alert(s) which highlight the potential for a release or other hazardous condition

◯ EQUIPMENT BOUNDARY DEFINITION (ANNEX A.2.3)

NOTE: Mark In Scope elements of boundary definition for the equipment type. Remarks can be used to further comment on equipment boundary details

☐	Machinery Driver	Electric motor, turbine or engine
☐	Machinery Driven	Compressor, pump
☐	Power transmission	Gear box, coupling
☐	Machinery Controls	PLC, unit control panel
☐	Auxiliary Equipment	Equipment supporting machinery function such as lube oil pump, coolers, seal system, starter units.

☐	Process Equipment	Inlet scrubbers, discharge coolers and associated process equipment
☐	Process Controls	Process instruments controlling fluid conditions and machinery response
☐	Condition Monitoring	Instrument sensors and equipment used to monitor performance

REMARKS:

◯ RISK ASSESSMENT APPROACH (8.2, ANNEX A.2.4)

NOTE: Identify the risk assessment approach, or approaches, that were conducted and used as basis for Field Risk Assessment

☐ HAZOP ☐ PROCESS FAILURE MODES AND EFFECTS ANALYSIS (PFMEA) ☐ OTHER, PLEASE SPECIFY
☐ COF ASSESSMENT ☐ LAYERS OF PROTECTION ANALYSIS (LOPA)
☐ POF / COF ASSESSMENT (see 8.12 a-f) ☐ FAULT TREE ANALYSIS

REMARKS:

◯ RISK CONSEQUENCE CATEGORIES CONSIDERED

NOTE: At a minimum, safety and environment should be used. At Operators discretion, other categories may be applied such as financial, reputation, and cost

☑ SAFETY ☑ ENVIRONMENTAL ☐ ASSET / PRODUCTION / FINANCIAL ☐ OTHER, PLEASE SPECIFY IN REMARKS

◯ HIGH RISK THRESHOLD DEFINITION

NOTE: Identify the basis used for identification of HIGH risk items

☐ COMPANY RISK MATRIX - ATTACH COPY, INCLUDING RELEVANT DEFINITIONS
☐ API 691 RISK MATRIX (ANNEX A.2.4.6)
☐ OTHER, PLEASE SPECIFY IN REMARKS

REMARKS:

NOTE: When API 691 Risk Matrix is selected, Probability of Failure (POF) and Consequence of Failure (COF) definitions from Figure A.2 should be used

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○ FIELD RISK ANALYSIS RESULT (8.2, ANNEX A.2.4)

NOTE: Mark the overall risk assessment result

☐ ACCEPTABLE RISK AS-IS ☐ NEEDS RISK MITIGATION

○ UNMITIGATED HIGH RISK EQUIPMENT ITEMS (6.2.2, ANNEX A.2.4)

NOTE: Enter the risk analysis results below only for those failure mode, mechanism and cause combinations within the equipment boundary resulting in a HIGH risk rating

NOTE: The API 691 FMEA Worksheet may be used to conduct the detailed risk assessment (Annex I)

ID	MAINTAINABLE ITEM	RISK TYPE (Safety, Env, Other)	FAILURE DESCRIPTION (FAILURE MODE / MECHANISM / CAUSE)
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			

RISK MITIGATION - RECOMMENDED ACTIONS (8.3)

NOTE: Following the Field Risk Assessment, recommendations shall be assigned to ensure that adequate mitigation is achieved

○ RECOMMENDED SUPPLEMENTARY PROTECTIVE MEASURES (5.2.5)

NOTE: In the Remarks field below, describe any recommended supplementary protective measures to support risk mitigation

REMARKS:

○ RECOMMENDED DESIGN UPGRADES

NOTE: In the Remarks field below, describe any recommended design upgrades to support risk mitigation

REMARKS:

○ RECOMMENDED MAINTENANCE TASK UPGRADES (6.4, ANNEXES D and E)

NOTE: In the table below, identify any recommended updates to existing maintenance program tasks

NOTE: Task Types may include: **CM** - Condition Monitoring, **PM** - Preventive Maintenance, and **FF** - Failure Finding

NOTE: Mark 'Related Risk IDs' from the Risk Analysis Results table above where the recommendation was credited in the assessment of risk mitigation

NOTE: For tasks involving online data sampling, a frequency of "ONLINE" should be used

NOTE: Risk Mitigation task selection guidance and example templates is provided in Annex D. Guidance on condition monitoring and diagnostics is provided in Annex E.

ID	TASK TYPE	TASK DESCRIPTION	FREQUENCY	RELATED RISK IDs
A				
B				
C				
D				
E				
F				
G				
H				
I				
J				

energy API	JOB NO.						Revision
	ITEM NO.						
RISK-BASED MACHINERY MANAGEMENT	PURCHASE ORDER NO.						
API 691 ANNEX H.5	SPECIFICATION NO.						
EQUIPMENT DATASHEET	REVISION NO.				DATE		
OPERATIONS AND MAINTENANCE	PAGE	3	OF	4	BY		

◯ RECOMMENDED TRAINING

NOTE: In the Remarks field below, describe any recommended additional training requirements to support risk mitigation

REMARKS:

RELIABILITY DATA COLLECTION AND ANALYSIS (A.2.4.9)

◯ HISTORICAL FAILURE EVENT DATA

NOTE: If available, provide information below for loss of containment or potential loss of containment failures that have occurred since the previous risk assessment.

NOTE: Mark as "In Scope" those failure events that should be included in MBTR and Weibull Analysis

In Scope	DATE	MAINTAINABLE ITEM	FAILURE EVENT (EQUIPMENT, FAILURE MODE)	CONSEQUENCE	ROOT CAUSE
☐					
☐					
☐					
☐					
☐					
☐					
☐					
☐					
☐					
☐					

SAFE OPERATING LIMITS (6.6)

☐ SAFE OPERATING LIMITS (SOLs)

NOTE: Note the Manufacturer shall define all API 691 IOW Critical Limits. The Operator shall use this information to determine safe operating limits (SOLs)

NOTE: Note the SOLs for the API 691 required design basis elements design basis below. Additional SOLs should be added if applicable. Remarks can be used to further comment.

#	DESIGN BASIS ELEMENT	SOL VALUE
1	Maximum allowable vibration	
2	Maximum allowable suction pressure	
3	Minimum allowable suction pressure	
4	Maximum allowable casing pressure	
5	Maximum allowable inlet temperature	
6	Maximum allowable speed	
7	Minimum continuous stable flow	
8	Maximum allowable solids concentration	
9	Maximum allowable corrosive limits	
10	Maximum allowable bearing temperature	
11		
12		
13		
14		
15		
16		

REMARKS:

REMARKS AND/OR SPECIAL REQUIREMENTS

energy API	JOB NO.						Revision
	ITEM NO.						
RISK-BASED MACHINERY MANAGEMENT	PURCHASE ORDER NO.						
API 691 ANNEX H.5	SPECIFICATION NO.						
EQUIPMENT DATASHEET	REVISION NO.				DATE		
OPERATIONS AND MAINTENANCE	PAGE	4	OF	4	BY		

ADDITIONAL REQUIREMENTS

○ ADDITIONAL REQUIREMENTS

NOTE: Mark the relevant items below that should be addressed by the Responsible party as indicated. Items that are checked by default indicate Normative requirements

☑	DOCUMENTED TRAINING PLAN (8.4)
☐	OPERATING PROCEDUREES (8.4)
☐	MAINTENANCE PROCEDURES (8.4)
☐	AUDIT PROCESS (8.4)
☐	INCIDENT INVESTIGATION PROCEDURES (8.4)
☐	MANAGEMENT OF CHANGE PROCESS (8.4)
☐	EMERGENCY RESPONSE PLAN (8.4)
☐	PRE-TURNAROUND RISK VALIDATION CHECKLIST REVIEWS (ANNEX B.5.1)
☐	MACHINERY MINOR AND MAJOR OVERHAUL RISK VALIDATION CHECKLIST REVIEWS (ANNEX B.5.2)
☐	ADDITIONAL PRESSURE BOUNDARY INSPECTIONS FOR MACHINERY IN CORROSIVE, EROSIVE, HARSH SERVICE (ANNEX B.5.3)

REFEERENCE DOCUMENTATION

○ INCLUDED DOCUMENTS (9.6)

NOTE: Mark the required documents that should be retained – record copy or maintained " as operating". Include additional key documents in the blank cells

NOTE: Items that are checked by default indicate required data to conduct a Field Risk Assessment.

REQUIRED	DOCUMENT	REV.#	DOCUMENT NUMBER
☑	Required Documents From Earlier Life Cycle Phases		
☑	Changes Under the MOC Process to Required Documents for Earlier Life Cycle Phases		
☑	Field Risk Assessments (OC or DRP, 8.2.5)		
☐	RAM Data Base (OC, 8.3.4)		
☐	Field Performance Test Report On Process Gas (OC or DRP, 8.3.7)		
☐			
☐			
☐			
☐			
☐			
☐			
☐			
☐			
☐			
☐			

REMARKS AND/OR SPECIAL REQUIREMENTS

Annex I
(informative)

API 691 FMEA Worksheet

I.1 Introduction

The purpose and intent of the API 691 FMEA worksheet is to provide a suggested methodology and template for machinery. Companies may use their own format.

The FMEA worksheet can be used in a DFMEA or PFMEA as outlined in Annex A and can be used in conjunction with the failure modes, mechanisms, and cause codes provided in Annex C.

I.2 API 691 FMEA Worksheet

The API 691 FMEA worksheet is shown in Figure I.1. Definitions for each of the FMEA worksheet data fields are shown in Figure I.2.

energy API			JOB NO.		REMARKS:
			ITEM NO.		
RISK-BASED MACHINERY MANAGEMENT API 691 ANNEX I: PROCESS FAILURE MODES AND EFFECTS ANALYSIS (PFMEA) WORKSHEET			PURCHASE ORDER NO.		
			SPECIFICATION NO.		
			REVISION NO.		
			DATE		
FOR			MANUFACTURER		
SITE			MODEL		
UNIT			SERIAL NUMBER		
SERVICE	☐	CONTINUOUS	TAG NO.		
	☐	INTERMITTENT	P&ID SHEET NO.		
	☑	STANDBY	NO. REQUIRED		

PRE-MITIGATED RISK ASSESSMENT									COF					MITIGATED RISK ASSESSMENT			COF				
Item #	Functional Performance Standard	Functional Failure/Loss of Performace	Failure Mode	Failure Effect(s)	Failure Cause(s)	Failure Mechanism(s)	Existing Safeguards	Detection	Safety	Environment	Other	POF	RPN	Mitigating Actions	Action Owner/Due Date	Detection (Rate 1-5)	Safety	Environment	Other	POF	RPN

Figure I.1—API 691 Machinery FMEA Worksheet

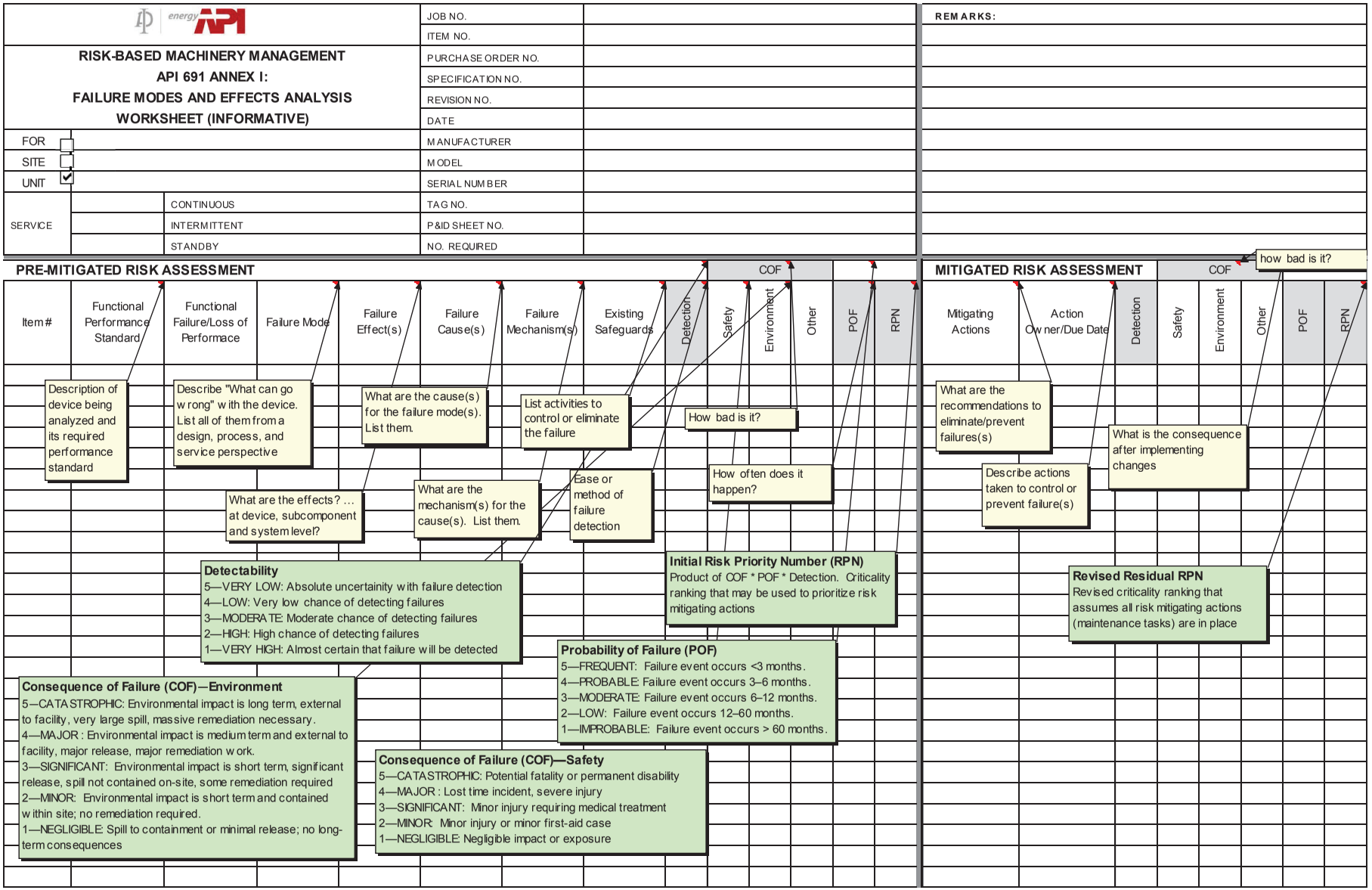

Figure I.2—API 691 Machinery FMEA Worksheet Definitions

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