Gas Turbines for the Petroleum, Chemical, and Gas Industry Services

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Foreword

This standard is based on the accumulated knowledge and experience of manufacturers and users of gas turbines. The objective of this standard is to provide a purchase specification to facilitate the procurement and manufacture of gas turbines for use in petroleum, chemical, and gas industry services.

Energy conservation is of concern and has become increasingly important in all aspects of equipment design, application, and operation. Thus, innovative energy conserving approaches should be aggressively pursued by the manufacturer and the user during these steps. Alternative approaches that may result in improving energy utilization should be thoroughly investigated and brought forth. This is especially true of new equipment proposals, since the evaluation or purchase options will be based increasingly on total life costs as opposed to acquisition cost alone. Equipment manufacturers, in particular, are encouraged to suggest alternatives to those specified when such approaches achieve improved energy effectiveness and reduced total life costs without sacrifice of safety or reliability.

This standard requires the purchaser to specify certain details and features. Although it is recognized that the purchaser may desire to modify, delete, or amplify sections of this standard, it is strongly recommended that such modifications, deletions, and amplifications be made by supplementing this standard, rather than by rewriting or incorporating sections thereof into another standard.

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Shall: As used in a standard, “shall” denotes a minimum requirement in order to conform to the standard.

Should: As used in a standard, “should” denotes a recommendation or that which is advised but not required in order to conform to the standard.

May: As used in a standard, “may” denotes a course of action permissible within the limits of a standard.

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Suggested revisions are invited and should be submitted to the Standards Department, API, 200 Massachusetts Avenue, NW, Suite 1100, Washington, DC 20001, standards@api.org.

Important Information Concerning Use of Asbestos or Alternative Materials

Asbestos is specified or referenced for certain components of the equipment described in some API standards. It has been of extreme usefulness in minimizing fire hazards associated with petroleum processing. It has also been a universal sealing material, compatible with most refining fluid services.

Certain serious adverse health effects are associated with asbestos, among them the serious and often fatal diseases of lung cancer, asbestosis, and mesothelioma (a cancer of the chest and abdominal linings). The degree of exposure to asbestos varies with the product and the work practices involved.

Consult the most recent edition of the Occupational Safety and Health Administration (OSHA), U.S. Department of Labor, Occupational Safety and Health Standard for Asbestos, Tremolite, Anthophyllite, and Actinolite, 29 *Code of Federal Regulations* Section 1910.1001; the U.S. Environmental Protection Agency (EPA), National Emission Standard for Asbestos, 40 *Code of Federal Regulations* Sections 61.140 through 61.156; and the EPA rule on labeling requirements and phased banning of asbestos products (Sections 763.160 through 763.179).

There are currently in use and under development a number of substitute materials to replace asbestos in certain applications. Manufacturers and users are encouraged to develop and use effective substitute materials that can meet the specifications for, and operating requirements of, the equipment to which they would apply.

Safety and health information with respect to particular products or materials can be obtained from the employer, the manufacturer or supplier of that product or material, or the material safety datasheet.

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1 Scope

1.1 General

This standard covers the minimum requirements for open-, simple-, and regenerative-cycle combustion gas turbine units for services of mechanical drive, generator drive, or process gas generation. All auxiliary equipment required for operating, starting, controlling, and protecting gas turbine units is either discussed directly in this standard or referred to in this standard through references to other publications. Specifically, gas turbine units that are capable of firing gas or liquid or both are covered by this standard. This standard covers both industrial and aeroderivative gas turbines.

A bullet (•) at the beginning of a paragraph indicates that either a decision is required or further information is to be provided by the purchaser. The information should be indicated on the datasheets (see Annex A); otherwise, it should be stated in the quotation request or in the order.

1.2 Alternative Designs

Vendor may offer alternative designs.

1.3 Conflicts

In case of conflicts between this standard and the inquiry, the information in the inquiry shall govern. At time of order, the order shall govern.

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 *Manual of Petroleum Measurement Standards* (*MPMS*) Chapter 15:2001, *Guidelines for Use of the International System of Units (SI) in the Petroleum and Allied Industries*

API Recommended Practice 500, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2*

API Recommended Practice 505, *Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2*

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—185 kW (250 hp) through 2240 kW (3000 hp)*

API Recommended Practice 551, *Process Measurement*

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 670, *Machinery Protection Systems*

API Standard 671, *Special-purpose Couplings for Petroleum, Chemical, and Gas Industry Services*

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

API Technical Report 684-1, *API Standard Paragraphs Rotordynamic Tutorial: Lateral Critical Speeds, Unbalance Response, Stability, Train Torsionals, and Rotor Balancing*

API Recommended Practice 686, *Recommended Practice for Machinery Installation and Installation Design*

API Recommended Practice 687, *Rotor Repair*

API Recommended Practice 691, *Risk-based Machinery Management*

ABMA Standard 7 [1], *Shaft and Housing Fits for Metric Radial Ball and Roller Bearings (Except Tapered Roller Bearings) Conforming to Basic Boundary Plan*

ABMA Standard 9, *Load Ratings and Fatigue Life for Ball Bearings*

ABMA Standard 11, *Load Ratings and Fatigue Life for Roller Bearings*

AGMA 2101-D04 [2], *Fundamental Rating Factors and Calculation Methods for Involute Spur and Helical Gear Teeth*

AGMA 6123-C16, *Design Manual for Enclosed Epicyclic Gear Drives*

AISI 1020 [3], *Case Hardening and General Purpose Steel*

ASME B1.1 [4], *Unified Inch Screw Threads (UN, UNR, and UNJ Thread Forms)*

ASME B16.5, *Pipe Flanges and Flanged Fittings: NPS 1/2 through NPS 24, Metric/Inch Standard*

ASME B16.9, *Factory-Made Wrought Buttwelding Fittings*

ASME B30.2, *Overhead and Gantry Cranes (Top Running Bridge, Single or Multiple Girder, Top Running Trolley Hoist)*

ASME B30.16, *Overhead Underhung and Stationary Hoists*

ASME B30.17, *Cranes and Monorails (With Underhung Trolley or Bridge)*

ASME B31.3, *Process Piping*

ASME B36.10M, *Welded and Seamless Wrought Steel Pipe*

ASME B36.19M, *Stainless Steel Pipe*

ASME B46.1, *Surface Texture (Surface Roughness, Waviness, and Lay)*

ASME B133.8, *Gas Turbine Installation Sound Emissions*

ASME *Boiler and Pressure Vessel Code* (*BPVC*), *Section V: Nondestructive Examination*

ASME *BPVC*, *Section VII: Recommended Guidelines for the Care of Power Boilers*

ASME *BPVC*, *Section VIII, Division 1: Rules for Construction of Pressure Vessels*

ASME *BPVC*, *Section VIII, Division 2: Alternative Rules*

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1 American Bearing Manufacturers Association, 1001 N. Fairfax Street, Suite 500, Alexandria, Virginia 22314, https://www.americanbearings.org.

2 American Gear Manufacturers Association, 1001 N. Fairfax Street, Suite 500, Alexandria, Virginia 22314, www.agma.org.

3 American Iron and Steel Institute, 25 Massachusetts Ave., NW, Suite 800, Washington, District of Columbia 20001, https://www.steel.org.

4 American Society of Mechanical Engineers, Two Park Avenue, New York, New York 10016, www.asme.org.

ASME *BPVC*, *Section IX: Welding and Brazing Qualifications*

ASME BTH-1, *Design of Below-the-Hook Lifting Devices*

ASME PTC 1, *General Instructions*

ASME PTC 22, *Performance Test Code on Gas Turbines*

ASME Y14.2M, *Line Conventions and Lettering*

ASTM A123/A123M [5], *Standard Specification for Zinc (Hot-Dip Galvanized) Coatings on Iron and Steel Products*

ASTM A182/A182M, *Standard Specification for Forged or Rolled Alloy and Stainless Steel Pipe Flanges, Forged Fittings, and Valves and Parts for High-Temperature Service*

ASTM A193/A193M, *Standard Specification for Alloy-Steel and Stainless Steel Bolting for High Temperature or High Pressure Service and Other Special Purpose Applications*

ASTM A194/A194M, *Standard Specification for Carbon Steel, Alloy Steel, and Stainless Steel Nuts for Bolts for High Pressure or High Temperature Service, or Both*

ASTM A240/A240M, *Standard Specification for Chromium and Chromium-Nickel Stainless Steel Plate, Sheet, and Strip for Pressure Vessels and for General Applications*

ASTM A247, *Standard Test Method for Evaluating the Microstructure of Graphite in Iron Castings*

ASTM A269/A269M, *Standard Specification for Seamless and Welded Austenitic Stainless Steel Tubing for General Service*

ASTM A312/A312M, *Standard Specification for Seamless, Welded, and Heavily Cold Worked Austenitic Stainless Steel Pipes*

ASTM A320/A320M, *Standard Specification for Alloy-Steel and Stainless Steel Bolting for Low-Temperature Service*

ASTM A388/A388M:2016, *Standard Practice for Ultrasonic Examination of Steel Forgings*

ASTM A395/A395M:2014, *Standard Specification for Ferritic Ductile Iron Pressure-Retaining Castings for Use at Elevated Temperatures*

ASTM A403/A403M, *Standard Specification for Wrought Austenitic Stainless Steel Piping Fittings*

ASTM A515/A515M, *Standard Specification for Pressure Vessel Plates, Carbon Steel, for Intermediate- and Higher-Temperature Service*

ASTM A563, *Standard Specification for Carbon and Alloy Steel Nuts*

ASTM A578/A578M, *Standard Specification for Straight-Beam Ultrasonic Examination of Rolled Steel Plates for Special Applications*

ASTM A609/A609M, *Standard Practice for Castings, Carbon, Low-Alloy, and Martensitic Stainless Steel, Ultrasonic Examination Thereof*

ASTM D1655, *Standard Specification for Aviation Turbine Fuels*

ASTM D2880, *Standard Specification for Gas Turbine Fuel Oils*

ASTM D4304, *Standard Specification for Mineral and Synthetic Lubricating Oil Used in Steam or Gas Turbines*

ASTM D5445-05, *Standard Practice for Pictorial Markings for Handling of Goods*

ASTM E94/E94M, *Standard Guide for Radiographic Examination Using Industrial Radiographic Film*

ASTM E165/E165M, *Standard Practice for Liquid Penetrant Testing for General Industry*

ASTM E709, *Standard Guide for Magnetic Particle Testing*

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5 ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.

ASTM E1417/E1417M, *Standard Practice for Liquid Penetrant Testing*

ATEX Directive 2014/34/EU of the European Parliament and of the Council of 26 February 2014 on the harmonisation of the laws of the Member States relating to equipment and protective systems intended for use in potentially explosive atmospheres (recast)

AWS D1.1/D1.1M [6], *Structural Welding Code—Steel*

CSA C22.1-06 [7], *Canadian Electrical Code, Part I, Safety Standard for Electrical Installations*

EN 614-1 [8], *Safety of machinery—Ergonomic design principles—Part 1: Terminology and general principles*

EN 779, *Particulate air filters for general ventilation—Determination of the filtration performance*

EN 1822, *High efficiency air filters (EPA, HEPA and ULPA)—Part 1: Classification, performance testing, marking*

IEC 60079 [9], *Explosive atmospheres*

IEC 60034-1, *Rotating electrical machines—Part 1: Rating and performance,* 11th Edition

IEC 60204-1, *Safety of machinery—Electrical equipment of machines—Part 1: General requirements*

IEC 60529, *Degrees of protection provided by enclosures (IP code)*

IEEE 841 [10], *Standard for the Petroleum and Chemical Industry—Premium-Efficiency, Severe-Duty, Totally Enclosed Fan-Cooled (TEFC) Squirrel Cage Induction Motors—Up to and Including 370 kW (500 hp)*

ISO 261 [11], *General purpose metric screw threads—General plan*

ISO 281, *Rolling bearings—Dynamic load ratings and rating life*

ISO 2314, *Gas turbines—Acceptance tests*

ISO 3448, *Industrial liquid lubricants—ISO viscosity classification*

ISO 3744, *Acoustics—Determination of sound power levels and sound energy levels of noise sources using sound pressure—Engineering methods for an essentially free field over a reflecting plane*

ISO 3977-3, *Gas turbines—Procurement—Part 3: Design requirements*

ISO 4386-1, *Plain bearings—Metallic multilayer plain bearings—Part 1: Non-destructive ultrasonic testing of bond of thickness greater than or equal to 0,5 mm*

ISO 6183, *Fire protection equipment—Carbon dioxide extinguishing systems for use on premises—Design and installation*

ISO 6708, *Pipework components—Definition and selection of DN (nominal size)*

ISO 8068, *Lubricants, industrial oils and related products (class L)—Family T (Turbines)—Specification for lubricating oils for turbines*

ISO 8501, *Preparation of steel substrates before application of paints and related products*

ISO 9606-1, *Qualification testing of welders—Fusion welding—Part 1: Steels*

ISO 10380, *Pipework—Corrugated metal hoses and hose assemblies*

ISO 10474, *Steel and steel products—Inspection documents*

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[6] American Welding Society, 8669 NW 36 Street, # 130, Miami, Florida 33166, www.aws.org.

[7] CSA Group, 178 Rexdale Blvd., Toronto, Canada M9W 1R3, https://www.csagroup.org.

[8] European Committee for Standardization (CEN), Management Centre, Rue de la Science 23, B - 1040 Brussels, Belgium, https://www.cen.eu.

[9] International Electrotechnical Commission, 3 Rue de Varembé, CH-1211, Geneva 20, Switzerland, www.iec.ch.

[10] IEEE, 445 Hoes Lane, Piscataway, New Jersey 08854, www.ieee.org.

[11] International Organization for Standardization, ISO Central Secretariat, Chemin de Blandonnet 8, CP 401 – 1214 Vernier, Geneva, Switzerland, www.iso.org.

ISO 10494, *Turbines and turbine sets—Measurement of emitted airborne noise—Engineering/survey method*

ISO 14123-1, *Safety of machinery—Reduction of risks to health resulting from hazardous substances emitted by machinery—Part 1: Principles and specifications for machinery manufacturers*

ISO 14520, *Gaseous fire-extinguishing systems—Physical properties and system design*

ISO 14691, *Petroleum, petrochemical and natural gas industries—Flexible couplings for mechanical power transmission—General-purpose applications*

ISO 15465, *Pipework—Stripwound metal hoses and hose assemblies*

ISO 17784, *Rubber and plastics hoses and hose assemblies—Guide for use by purchasers, assemblers, installers and operating personnel*

ISO 20816-1, *Mechanical vibration—Measurement and evaluation of machine vibration—Part 1: General guidelines*

ISO 20816-4, *Mechanical vibration—Measurement and evaluation of machine vibration—Part 4: Gas turbines in excess of 3 MW, with fluid-film bearings*

ISO 21789, *Gas turbine applications—Safety*

ISO 21940, *Mechanical vibration—Rotor balancing*

ISO 21940-12, *Mechanical vibration—Rotor balancing—Part 12: Procedures and tolerances for rotors with flexible behaviour*

MIL-S-8879 [12], *Screw Threads, Controlled Radius Root with Increased Minor Diameter, General Specification*

NACE MR0103 [13], *Petroleum, Petrochemical and Natural Gas Industries—Metallic Materials Resistant to Sulfide Stress Cracking in Corrosive Petroleum Refining Environments*

NACE MR0175, *Petroleum and Natural Gas Industries—Materials for Use in H_2S-Containing Environments in Oil and Gas Production*

NEMA 250 [14], *Enclosures for Electrical Equipment (1000 Volts Maximum)*

NFPA 12 [15], *Standard on Carbon Dioxide Extinguishing Systems*

NFPA 70, *National Electrical Code*

NFPA 72, *National Fire Alarm and Signaling Code*

NFPA 750, *Standard on Water Mist Fire Protection Systems*

NFPA 2001, *Standard on Clean Agent Fire Extinguishing Systems*

NFPA 2010, *Standard for Fixed Aerosol Fire-Extinguishing Systems*

OSHA 29 *Code of Federal Regulations (CFR)* 1910, *Occupational Safety and Health Standards*

OSHA 29 *CFR* 1926, *Safety and Health Regulations for Construction*

SAE B92.1 [16], *Involute Splines and Inspection*

SAE J518, *Hydraulic Flanged Tube, Pipe, and Hose Connections, Four-Bolt Split Flange Type*

SSPC SP6 [17], *Commercial Blast Cleaning (also known as NACE No. 3)*

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[12] US Department of Defense, Document Automation and Production Service, Building 4/D, 700 Robbins Avenue, Philadelphia, Pennsylvania 19111, https://www.defense.gov.

[13] NACE International, 15835 Park Ten Place, Houston, Texas 77084, www.nace.org.

[14] National Electrical Manufacturers Association, 1300 17th Street N 900, Arlington, Virginia 22209, www.nema.org.

[15] National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169, www.nfpa.org.

[16] SAE International, 400 Commonwealth Drive, Warrendale, Pennsylvania 15096, www.sae.org.

[17] The Society for Protective Coatings, 800 Trumbull Drive, Pittsburgh, Pennsylvania 15205, www.sspc.org.

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply. See Annex D for more information.

3.1.1
alarm point
Preset value of a measured parameter at which an alarm is activated to warn of a condition that requires corrective action. All alarm points have to be measured; however, all measured points do not have to be alarmed.

3.1.2
anchor bolts
Bolts used to attach the equipment to the support structure (concrete foundation or steel structure). (See 3.1.22 "hold-down bolts.")

3.1.3
axially split joint
Joint split with the principal face parallel to the shaft centerline.

3.1.4
blade lock-up speed
Speed of rotation at which a part span or tip damping device (whether joining all or multiple numbers of individual blades) becomes effective.

3.1.5
blades
Rotating airfoils for both compressors and turbines unless modified by an adjective.

3.1.6
chemiluminescence
A chemical reaction that gives off light without significant amounts of heat.

3.1.7
control system
Includes both gas turbine control system and API 670 machinery protection system.

3.1.8
conventional combustor
A chamber where the fuel and air mix by turbulence and diffusion (without a premixer) and burn over a wider flammability range of fuel-to-air ratios (FARs) compared to a premixed combustor.

NOTE See 3.1.49 "premixed combustor."

3.1.9
critical speed
Shaft rotational speed at which the rotor-bearing support system is in a state of resonance.

3.1.10
design
Manufacturer's calculated parameter. A term used by the equipment manufacturer to describe various parameters such as design power, design pressure, design temperature, or design speed. It is not intended for the purchaser to use this term.

3.1.11
diamètre nominal or **nominal diameter**
DN
Alphanumeric designation of size for components of a pipework system. (See 3.1.37 “nominal pipe size.”)

EXAMPLE DN 20

NOTE 1 Adapted from ISO 6708.

NOTE 2 The letters DN are followed by a dimensionless whole number that is indirectly related to the physical size, in millimeters, of the bore or outside diameter of the end connection.

NOTE 3 The number following the letters DN does not represent a measurable value.

NOTE 4 In those standards that use the DN designation system, any relationship between DN and component dimensions should be given, e.g. DN/OD or DN/ID.

3.1.12
dry low emissions
DLE
A combustion system using premixed combustors to minimize NO_X and CO exhaust emissions.

NOTE See 3.1.8 “conventional combustor.”

3.1.13
duty cycle
The expected operating mode (full or part load, steady or variable, continuous or intermittent operation) of the gas turbine.

NOTE The number of thermal cycles (i.e. stops, starts, and load variations) can have a significant impact on the life of turbine components.

3.1.14
expected availability
Expected percentage of time a gas turbine package is available for use over the service life.

NOTE Expected availability includes both unplanned and planned downtime.

3.1.15
expected reliability
Expected percent of time a gas turbine package is available for use over the service life, excluding planned maintenance.

NOTE Expected reliability quantifies unplanned downtime.

3.1.16
fuel-to-air ratio
FAR
Ratio of fuel to air on a mass basis, reciprocal of air-fuel-ratio.

3.1.17
filter stage
Section of a filter system designed to remove specific site contaminants.

3.1.18
gas generator
The portion of the gas turbine that primarily produces heated gas for the power turbine. Sometimes called “gas producer.”

3.1.19
gas turbine package
Includes the gas turbine and all accessories supplied by the vendor except the coupling, load gears, driven equipment, and common tools.

3.1.20
gauge board
Bracket or plate used to support and display gauges, switches, and other instruments. (See 3.1.46 "panel.") A gauge board is not a panel. A gauge board is open and not enclosed. A panel is an enclosure.

3.1.21
heat rate
Energy consumption of a prime mover per unit of output work. For gas turbines, the heat rate is calculated on the basis of the lower heating value of the fuel.

3.1.22
hold-down bolts or **mounting bolts**
Bolts holding the equipment to the mounting plate.

3.1.23
hydrodynamic bearings
Bearings that use the principles of hydrodynamic lubrication. The bearing surfaces are oriented so that relative motion forms an oil wedge, or wedges, to support the load without shaft-to-bearing contact.

3.1.24
informative
See 3.1.40 "normative."

NOTE An informative reference or annex provides advisory or explanatory information.

3.1.25
ISO-rated power
New, clean, continuous power developed by the gas turbine when it is operated at design firing temperature and speed at ISO 2314 standard reference conditions with no inlet or exhaust losses.

NOTE The ISO rating provides only general sizing information and is not to be confused with site rated power.

3.1.26
local
Position of devices on or near the equipment or console.

3.1.27
lower heating value
LHV
The amount of heat released by combusting a defined quantity where the latent heat of vaporization of water in the reaction products is not recovered. Also known as net calorific value or net heating value.

NOTE Typically measured in kJ/kg or Btu/lbm or Btu/scf.

3.1.28
maximum allowable temperature
Maximum continuous temperature for which the manufacturer has designed the equipment (or any part to which the term is referred) when handling the specified fluid at the specified maximum operating pressure.

3.1.29
maximum allowable working pressure
MAWP
Maximum continuous pressure for which the manufacturer has designed the equipment (or any part to which the term is referred) when handling the specified fluid at the specified maximum operating temperature.

3.1.30
maximum continuous speed
$N_{\mathbf{mc}}$
Highest speed at which the manufacturer's design will permit continuous operation.

3.1.31
maximum exhaust pressure
Highest exhaust back pressure at which the gas turbine is required to operate continuously.

3.1.32
minimum allowable speed
$N_{\mathbf{ma}}$
Lowest turbine output shaft speed (revolutions per minute) at which the manufacturer's design will permit continuous operation.

NOTE Minimum allowable speed can be set by many factors; these include, but are not limited to, the following: location of critical speeds (lateral and torsional), blade natural frequencies, minimum differentials that need to be developed across close clearances for lubrication, cooling, rotordynamic damping and stiffening, and minimum speed of shaft driven lubricating pumps.

3.1.33
minimum allowable temperature
Lowest temperature for which the manufacturer has designed the equipment (or any part to which the term is referred).

3.1.34
modified Wobbe index
MWI
A relationship to describe the fuel energy density, corrected with temperature (see E.6.3). See also 3.1.77 "Wobbe index."

3.1.35
mounting plate
Device used to attach equipment to concrete foundations or steel supports. This is either a baseplate(s), soleplates, or chockplates.

3.1.36
natural gas liquids
NGL
Hydrocarbons liquefied at the surface in field facilities or in gas processing plants.

NOTE Natural gas liquids include ethane, propane, butanes, and natural gasoline.

3.1.37
nominal pipe size
NPS
Value approximately equal to the diameter in inches (see 3.1.11 "diamètre nominal").

EXAMPLE NPS $^3/_4$.

NOTE 1 Refer to ASME B31.3.

NOTE 2 The letters NPS are followed by a number that is related to the physical size, in inches of the bore or outside diameter of the pipe.

3.1.38
normal operating point
Point at which usual operation is expected and optimum efficiency is desired.

NOTE This point is usually the point at which the vendor certifies the heat rate is within the tolerances stated in this standard (see 6.1.8 and 6.1.9). Parameters used to determine the normal operating point include speed, site conditions, emissions, and fuel composition.

3.1.39
normal stop
A nonexpedited gas turbine stop.

NOTE A normal stop can be manually initiated by an operator or an automatically scheduled stop sequence. It is not an emergency stop or trip.

3.1.40
normative
Required. (See 3.1.24 "informative.")

NOTE A normative reference or annex invokes a requirement or mandate of the specification.

3.1.41
nozzles (fixed and variable)
Turbine stationary (nonrotating) airfoils.

3.1.42
NPT
American National Standard Pipe Taper thread form designation for pipe threads.

EXAMPLE $^{3}/_{4}$ – 14 NPT.

NOTE 1 It is comprised of a number representing nominal pipe size followed by the number of threads per inch and the letters NPT representing the thread series.

NOTE 2 Pipe size and number of threads per inch can be found in ASME B1.20.1.

3.1.43
observed
Classification of inspection or test where the purchaser is notified of the schedule and the inspection or test is performed even if the purchaser or their representative is not present, i.e. not a witness point.

3.1.44
open cycle
A process in which the working medium enters the gas turbine from the atmosphere and discharges to the atmosphere directly or indirectly through exhaust heat recovery equipment.

3.1.45
owner
Final recipient of the equipment or their designated agent.

3.1.46
panel
Enclosure used to mount, display, and protect gauges, switches, and other instruments.

3.1.47
potential maximum power
Expected power capability when the gas turbine is operated at maximum allowable firing temperature, rated speed or under other limiting conditions as defined by the manufacturer and within the range of specified site values, including the total operating envelope (see 6.14.1.2).

NOTE Potential maximum power typically occurs at the minimum air inlet temperature and lowest MWI.

3.1.48
power turbine
Power extracting turbine stage(s) that is mechanically coupled to the load but is not mechanically connected to the shaft of the gas generator. Sometimes called a "free power turbine."

NOTE 1 One gas turbine can have multiple turbine sections, e.g. high-pressure turbine (HPT), intermediate-pressure turbine (IPT), low-pressure turbine (LPT), and a power turbine. See Figure 1.

NOTE 2 On a single-shaft gas turbine the power turbine, gas generator, and load are all mechanically connected.

3.1.49
premixed combustor
A chamber where fuel and air are mixed uniformly (in a premixer) and then transported to the flame zone.

NOTE This is a low NO_X combustor. See 3.1.8 "conventional combustor."

3.1.50
pressure casing
Composite of all stationary pressure-containing parts of the unit, including all nozzles and other attached parts.

3.1.51
purchaser
Agency that issues the order and specification to the vendor.

NOTE The purchaser can be the owner of the plant in which the equipment is to be installed or the owner's appointed agent.

3.1.52
radially split
Split with the principal joint perpendicular to the shaft centerline.

3.1.53
rated speed (mechanical drive applications)
Gas turbine output shaft speed (revolutions per minute) required to develop site rated power (see 3.1.66).

NOTE Normally, the gas turbine rated speed corresponds to the driven equipment rated speed.

3.1.54
rated speed (generator drive applications)
Gas turbine output shaft speed (revolutions per minute) required to develop site rated power (see 3.1.66) at synchronous generator speed.

3.1.55
regenerative cycle
A process in which the gas turbine exhaust is used to heat (by heat exchange) combustion air from the compressor.

3.1.56
relief valve set pressure
Pressure at which a relief valve starts to lift.

3.1.57
remote
Location of a device when located away from the equipment or console, typically in a control room.

3.1.58
risk assessment
A systematic process of identifying, quantifying, and evaluating the potential risks involved in the design of the gas turbine package.

NOTE Includes failure modes and effects analysis (FMEA) and hazard and operability study (HAZOP).

3.1.59
roughness value
R_a
Arithmetical average of the absolute value of the profile height deviations recorded within the evaluation length and measured from the mean line.

NOTE 1 Adapted from ASME B46.1.

NOTE 2 It is the average variation in height of the entire surface, within the sampling length, from the mean line.

3.1.60
service life
The duration of time that a system or component can be utilized at site rated conditions, power and duty cycle and while following the vendor defined operation and maintenance requirements. See 6.1.2.

3.1.61
shutdown
Gas turbine package condition, as determined by the equipment user, which requires action to stop the gas turbine.

NOTE Shutdowns can be broken into several different types (e.g. manual lock-out, cooldown time), depending upon initiating event. It can be automatically implemented through the control system or manually initiated (by pressing the emergency shutdown button or normal stop button) (see 7.5.5.7.2 and 7.5.5.7.5).

3.1.62
shutdown set point
Preset value of a measured parameter at which automatic or manual shutdown of the system or equipment is required.

3.1.63
simple-cycle
A process in which the gas turbine exhaust is discharged to the atmosphere without exhaust gas heat recovery.

3.1.64
site rated conditions
Conditions used to determine site rated power. See 6.1.24.

3.1.65
site rated firing temperature
Turbine inlet total temperature, measured at a location immediately upstream of the first-stage turbine nozzles, required to meet site rated power.

3.1.66
site rated power
Power of a new and clean gas turbine package at site rated conditions with air filters at high differential pressure alarm. See 6.1.22 through 6.1.24.

3.1.67
special tool
Tool or fixture that is not a commercially available catalog item.

3.1.68
stator outlet temperature
Gas path temperature exiting the first stator or vane. This is the gas temperature entering the first turbine blade.

3.1.69
superheat
The temperature that a gas would need to be reduced, at constant pressure, to start condensation. Temperature margin of a gas above its boiling point.

3.1.70
thermal efficiency
Ratio of the energy output at the gas turbine output shaft (or generator terminals) to the energy input (based on the lower heating value of the fuel) in the same units expressed as a percentage.

NOTE External auxiliaries directly driven are included in parasitic losses.

3.1.71
total indicator reading
total indicated runout
TIR
Difference between the maximum and minimum readings of a dial indicator or similar device, monitoring a face or cylindrical surface during one complete revolution of the monitored surface.

NOTE For a cylindrical surface, the total indicated runout implies an eccentricity equal to half the reading. For a flat face, the indicated runout implies an out-of-square equal to the reading.

3.1.72
trip (also known as emergency shutdown)
Automated shutdown to ensure personnel safety (safety critical).

3.1.73
trip speed
Turbine speed at which the independent emergency overspeed device shuts off fuel to the gas turbine.

3.1.74
vanes (fixed and variable)
Compressor stationary (nonrotating) airfoils.

NOTE Also known as blades.

3.1.75
vendor or **supplier**
Manufacturer or manufacturer's agent that supplies the equipment.

3.1.76
witnessed
A classification of inspection or test where the purchaser is notified of the timing of the inspection or test and a hold is placed on the inspection or test until the purchaser or the purchaser's representative is in attendance.

3.1.77
Wobbe index
WI
A relationship to describe the fuel energy density, uncorrected for temperature (see E.6.3). See also 3.1.34 "modified Wobbe index."

3.2 Acronyms and Abbreviations

For the purposes of this document, the following acronyms and abbreviations apply.

AC	alternating current
AF	amplification factor
AR	(ISO) air release (lubricants)
ATEX	atmosphères explosibles
BPVC	Boiler and Pressure Vessel Code
BX	nonjacketed flexible cable
CEMS	continuous emission monitoring systems
CFD	computation fluid dynamics
CFR	(United States) Code of Federal Regulations
CPU	central processing unit
DC	direct current
DCS	distributed control system
DLE	dry low emissions
DN	diamètre nominal
dT_{DB}	temperature drop, dry bulb
EPA	(ASHRAE) efficient particulate air (filters)
FAR	fuel-to-air ratio
FAT	factory acceptance test
FEA	finite element analysis
FMEA	failure modes and effects analysis
FOD	foreign object damage
HAZOP	hazard and operability study
HEPA	(ASHRAE) high-efficiency particulate air (filter)
HMI	human machinery interface
HP	power

HPC	high-pressure compressor
HPT	high-pressure turbine
IP	ingress protection
IPC	intermediate-pressure compressor
IPT	intermediate-pressure turbine
LHV	lower heating value
LPC	low-pressure compressor
LPT	low-pressure turbine
MAWP	maximum allowable working pressure
MERV	(ASHRAE) minimum efficiency reporting value
MIL	(United States) military defense standard
MPPS	(air filtration) most penetrating particle size efficiency
MWI	modified Wobbe index
NDE	nondestructive examination
NEC	(United States) *National Electric Code*
NGL	natural gas liquids
N_{mc}	maximum continuous speed
NO_X	oxides of nitrogen
NPS	nominal pipe size
NPT	(United States) national pipe thread
PEMS	predictive emissions monitoring systems
PLC	programmable logic controller
PMI	positive material identification
PTFE	polytetrafluoroethylene
PVC	polyvinyl chloride
RMS	root mean square
RTD	resistance temperature detector
SCO	selective catalytic oxidation

SCR	selective catalytic reduction
SI	Système International (International System of Units)
SIL	safety integrity level
SM	separation margin
SNCR	selective noncatalytic reduction
SO_X	oxides of sulfur
TFE	tetrafluoroethylene
UHC	unburned hydrocarbon
ULPA	(ASHRAE) ultra-low particle air (filter)
UN	unified constant pitch (thread)
UNR	unified rounded root (thread)
UNS	(ASTM) Unified Numbering System (materials)
UPS	uninterruptible power system
USC	United States customary (units)
VDDR	vendor drawing and data requirements
VFD	variable frequency drive
VG	(ISO) viscosity grade (lubricant)
VOC	volatile organic compounds
WI	Wobbe index
WLE	wet low emissions

4 General—Unit Responsibility

Unless otherwise specified, the gas turbine vendor shall have unit responsibility and shall ensure that all subvendors comply with the requirements of this standard and all reference documents. The technical aspects to be considered by the vendor include, but are not limited to, such factors as the power requirements, speed, rotation, general arrangement, couplings, dynamics, lubrication, sealing system, material test reports, instrumentation, piping, and conformance to specifications and testing of components.

5 Requirements

5.1 Units of Measure

Purchaser's use of a United States customary (USC) datasheet (see A.1) indicates the USC system of measurements shall be used for all data, drawings, and maintenance dimensions. Purchaser's use of Système International (SI) datasheet (see A.2) indicates that the SI system of measurements shall be used.

NOTE Dedicated datasheets for SI units and for USC units are provided in Annex A.

5.2 Statutory Requirements

The purchaser and vendor shall determine the measures to be taken to comply with any governmental codes, regulations, ordinances, directives, or rules that are applicable to the equipment, its packaging, and any preservatives used.

5.3 Documentation Requirements

• The hierarchy of documents shall be as specified.

NOTE Typical documents include purchase order, company and industry specifications, meeting notes, and modifications to these documents.

6 Basic Design

6.1 General

6.1.1 Technology Readiness Level

• **6.1.1.1** Only equipment that is field proven is acceptable. The purchaser shall specify the technology readiness level (TRL) from API 691 for qualified equipment.

NOTE Purchasers can use their engineering judgment in determining what equipment is field-proven.

• **6.1.1.2** If specified, vendor shall provide the documentation to demonstrate that all equipment proposed qualifies as field proven.

6.1.1.3 In the event no such equipment or documentation is available, vendor shall submit an explanation of how their proposed equipment can be considered field-proven.

NOTE A possible explanation can be that all components comprising the assembled machine satisfy the field-proven definition.

• **6.1.2** The gas turbine package shall be designed to meet or exceed the specified service life.

NOTE It is recognized that the package will contain components (e.g. galvanized structural steel or stainless steel inlet system) that will obtain long service life with minimal scheduled maintenance, whereas some components (e.g. gas generator, power turbine) will require multiple replacements or refurbishments to meet the service life.

6.1.3 Proposal shall include operation and maintenance requirements (with associated downtime) to achieve the gas turbine package service life (see 6.1.2). See 9.2.3.2 m).

6.1.4 Unless otherwise specified, the planned maintenance schedule of the gas turbine and control system shall not require a shutdown more frequently than once every 8760 operating hours.

NOTE 1 The 8760 hour applies to base-loaded machines using air and fuel that meets gas turbine manufacturer’s specifications.

NOTE 2 Some gas turbine models have borescope inspection intervals that are shorter than 8760 hours.

NOTE 3 Operation of a gas turbine beyond the gas turbine manufacturer’s inspection interval increases the likelihood of unplanned maintenance.

NOTE 4 Some applications need off-line water washing more frequently than 8760 hours to mitigate degradation and maintain power and efficiency.

• **6.1.5** If necessary, redundant components shall be installed to meet the minimum specified reliability and minimum specified availability.

a) Proposal shall provide the expected availability of the gas turbine package based on the stated site operating conditions and duty cycle. See 9.2.3.2 m).

b) Proposal shall provide the expected reliability of the gas turbine package based on the stated site operating conditions and duty cycle. See 9.2.3.2 m).

6.1.6 Proposal shall identify all single point failures that automatically shut down or trip the gas turbine package, including instrumentation and excluding components that cannot practically be made redundant. See 9.2.3.2 m).

NOTE Typical single point of failure issues are related to sensor failures, enclosure blowers, opening enclosure doors, but it is not practical to have all components be redundant, e.g. couplings, bearings, stator, casing, and rotors. The purchaser can review failure modes and influence the design.

• **6.1.7** The site rated power (with no negative tolerance) shall not be less than the driven equipment certified point power requirement plus the specified power margin.

NOTE For example if the driven equipment certified power requirement is 10 MW and the margin is 10 %, the site rated power needs to be at least 11 MW. The gas turbine rated point and driven equipment certified points are typically based on the same operating scenario.

• **6.1.8** The gas turbine package shall be designed for the normal operating point and all other specified operating conditions (see 3.1.38, 6.6, and Annex A).

6.1.9 The heat rate shall not exceed the guaranteed heat rate by more than 3 % at the normal operating point (see 6.1.8).

6.1.10 The gas turbine shall be one of the arrangements in Figure 1.

6.1.11 For mechanical drive applications, the gas turbine should have a free power turbine.

NOTE A free power turbine usually enables a wider speed range and the ability to start while the driven equipment is with load (e.g. compressor pressurized).

6.1.12 Proposal shall identify the gas turbine arrangement (see Figure 1). See 9.2.3.2 m).

6.1.13 Gas turbine packages shall be suitable for nonoperating periods of up to 3 weeks, under site conditions (see 6.6), without requiring any preservation procedures.

NOTE Some manufacturers need some auxiliary systems (e.g. heaters) to remain in service during nonoperating periods.

6.1.14 Proposal shall describe any necessary procedures for shutdown periods longer than 3 weeks, under site conditions (see 6.6). See 9.2.3.2 m).

• **6.1.15** The output-shaft operating speed range of gas turbines for mechanical-drive applications shall be as specified. Where only one operating speed is specified for a mechanical-drive application, the minimum speed range shall be from 70 % to 105 % of rated speed.

6.1.16 The output-shaft operating speed range of gas turbines for electrical generator drive applications shall be 95 % to 105 % of rated speed.

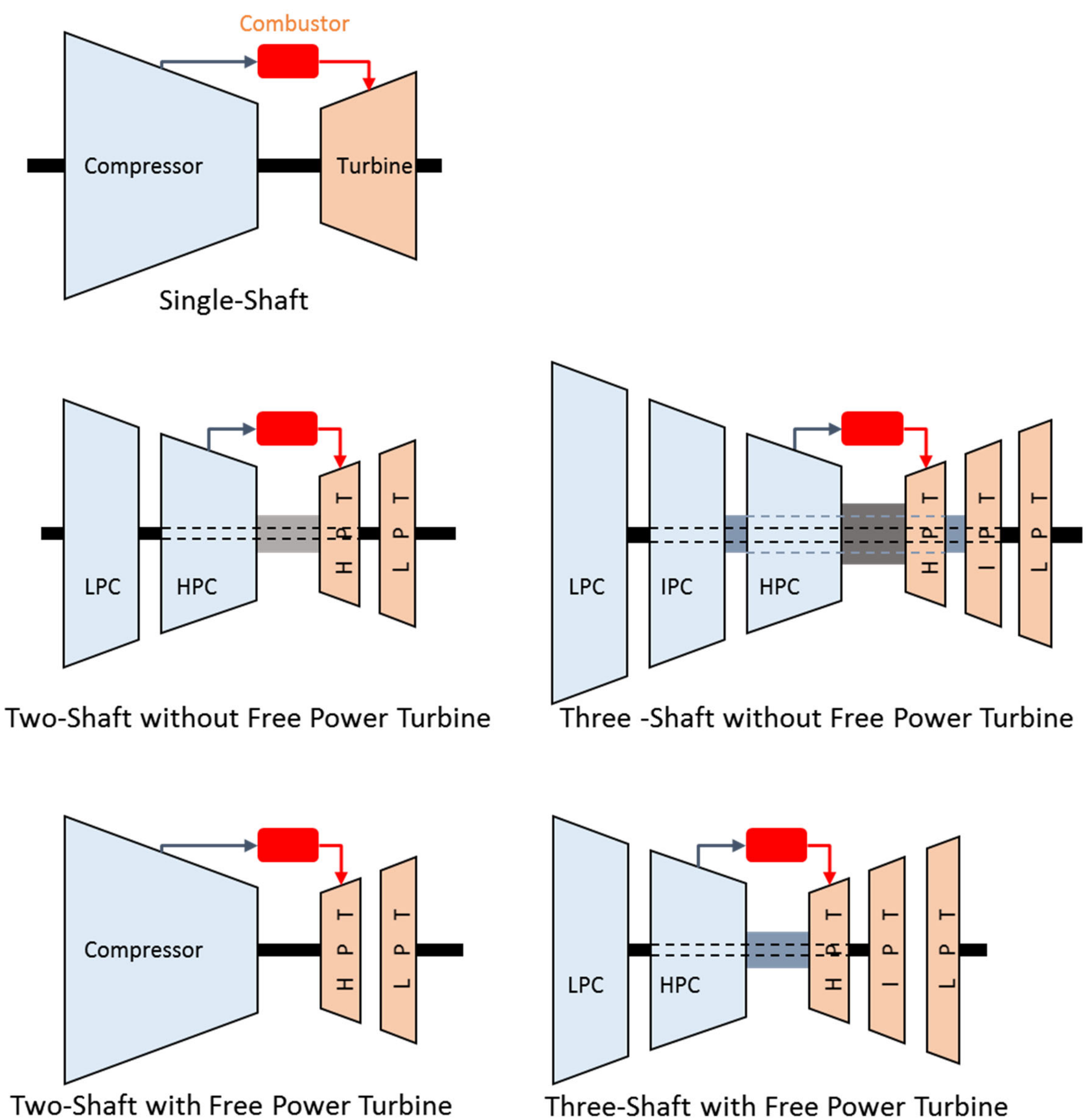


Figure 1—Gas Turbine Rotor Arrangements

6.1.17 Gas turbine package shall be designed for continuous service over the entire operating speed range (see 6.1.15 and 6.1.16) and power ranges including potential maximum power.

6.1.18 Proposal shall define the period between major overhauls while operating at potential maximum power and identify the maximum number for starts. See 9.2.3.2 m).

NOTE The period between major overhauls is based on an assumed number of starts.

6.1.19 After a normal stop, the gas turbine package shall permit immediate initiation of a normal start (no additional time added), subject to the driven equipment restrictions (see 7.1.4.1).

NOTE Transient thermal gradients following shutdown can delay restart.

6.1.20 Proposal shall define gas turbine cold start and hot restart restrictions and processes (e.g. with and without cooldown, with and without spin). See 9.2.3.2 m).

6.1.21 Equipment shall be designed to run without damage at any speed up to the highest trip speed in combination with any specific level of allowable temperature identified by the vendor.

6.1.22 For mechanical drive, site rated power and speed are referenced at the output shaft of the gas turbine ahead of any separate gear or piece of driven equipment.

NOTE For mechanical drive, site rated power excludes efficiency of all transmission and driven equipment.

• **6.1.23** For power generation, site rated power shall be referenced at the terminals of the generator and use the specified power factor.

NOTE For power generation, site rated power includes efficiency of gearbox and generator.

6.1.24 A new (less than 500 hours of operation) and clean gas turbine package shall be capable of producing site rated power, without exceeding the site rated firing temperature, at the following conditions:

a) rated speed;

• b) specified site rated dry bulb ambient air temperature (measured upstream of all air inlet systems) (see 6.6);

• c) specified altitude (see 6.6);

• d) specified site rated relative humidity (see 6.6);

• e) specified site rated fuel composition (see 7.9.2 and 7.9.4);

f) including losses from all inlet cooling or heating, exhaust heat recovery, and exhaust treatment systems (see 7.7.2.1.3.1, 7.7.2.1.3.2, 7.7.2.9.1.1, and 7.7.3.1.1):

   1) entire air inlet system installed;

   2) air filters at high differential pressure alarm;

   3) entire exhaust systems installed.

NOTE Purchaser to consider barometric variations and ambient temperature ranges when specifying the site rated conditions. The inlet air temperature specified for site rated conditions is not normally the highest or lowest recorded air temperature and humidity; this would result in extra equipment that would be rarely needed.

6.1.25 Proposal shall identify the fuel pressure and temperature limits necessary to generate site rated power (see 7.9.2.1). See 9.2.3.2 m).

6.1.26 N_{mc} shall not be less than 105 % of rated speed.

6.2 Air Emissions

• **6.2.1** Air emissions levels shall not be greater than the specified maximums with the specified fuel (see 7.9.2 and 7.9.4).

NOTE 1 Air emission maximums can include limits on NO_X, SO_X, CO, CO_2, hydrocarbons [unburned hydrocarbons (UHC), etc. SO_X and CO_2 are more influenced by fuel composition rather than gas turbine performance.

NOTE 2 Air emissions include gas turbine exhaust and package vents.

6.2.2 Unless otherwise specified, site background air emissions are assumed to be zero.

NOTE Gas turbine air emissions are additive to background air emissions levels.

6.2.3 Unless otherwise specified, all air emission abatement systems necessary to comply with 6.2.1 shall be supplied.

NOTE The complete abatement solution can be a joint effort of the vendor and the purchaser (e.g. fuel processing).

6.2.4 Proposal shall list any restrictions on gas turbine speed or load range related to air emissions abatement. See 9.2.3.2 m).

6.2.5 Vendor shall provide air emissions data necessary for the purchaser to obtain permits.

6.2.6 Proposal shall state expected air emission levels with the fuel composition (see 7.9.2 or 7.9.4) and site operating conditions (see 6.6). See 9.2.3.2 m).

• **6.2.7** If specified, the gas turbine may utilize steam or water injection to reduce exhaust emissions.

6.2.8 Proposal shall describe the effects (e.g. maintenance recommendations and parts replacement) of steam or water injection. See 9.2.3.2 m).

6.2.9 Proposal shall describe the required quantity and quality of steam or injection water. See 9.2.3.2 m).

6.3 Noise Emissions

• **6.3.1** Sound power levels shall not be greater than the specified maximums.

• **6.3.2** Sound pressure levels shall not be greater than the specified maximums.

NOTE There can be multiple sound pressure level requirements (e.g. different levels at different locations, near field, far field).

6.3.3 Unless otherwise specified, site background noise levels are assumed to zero.

NOTE Gas turbine noise is additive to background noise levels.

6.3.4 Unless otherwise specified, all noise attenuation systems shall be supplied.

6.3.5 Proposal shall list the predicted maximum attenuated sound pressure level and sound power level data per octave band for each principal noise source within the vendor scope (e.g. gas turbine enclosure, inlet, exhaust). See 9.2.3.2 m).

6.4 Cooling Water Systems

6.4.1 Unless otherwise specified, the water side of cooling water system(s) shall be in accordance with API 614.

6.4.2 If the criteria for minimum temperature rise and velocity over heat exchange surfaces result in a conflict, the purchaser will approve the final selection.

NOTE The criterion for velocity over heat exchange surfaces is intended to minimize water side fouling; the criterion for minimum temperature rise is intended to minimize the use of cooling water.

6.4.3 Provision shall be made for complete venting and draining of the system.

6.5 Package Design

6.5.1 The arrangement of the equipment, including piping and auxiliaries, shall be developed jointly by the purchaser and the vendor during the proposal phase. Pre-engineered packages with prearranged piping and equipment may be offered.

6.5.2 The arrangement of enclosure piping and conduits shall provide adequate clearance areas and safe access for operation and maintenance and shall not cause a maintenance obstruction.

6.5.3 Unless otherwise specified, all electrical installations shall conform to NFPA 70 [*National Electrical Code* (*NEC*)], or:

• a) if specified, all electrical installations shall conform to IEC 60079; or

• b) if specified, all electrical installations shall conform to ATEX 2014/34/EU; or

• c) if specified, all electrical installations shall conform to CSA C22-1-06.

• **6.5.4** Motors, electrical components, electrical installations, controls, and instrumentation shall be suitable for the specified area classification (class, division/zone, group).

NOTE Electrical devices on aeroderivative gas turbines are typically designed in accordance with aircraft explosion-proof requirements of MIL-E-5007.

6.5.5 Oil reservoirs and housings that enclose moving lubricated parts (such as bearings, shaft seals, highly polished parts, instruments, and control elements) shall be designed to minimize contamination by moisture, dust (particulates), and other foreign matter during periods of operation and idleness.

6.5.6 All equipment shall be designed to facilitate maintenance in the specified environmental conditions (see 6.6).

a) Major parts such as casing components and bearing housings shall be designed (shouldered or cylindrically doweled) and manufactured to ensure that vendor's alignment specifications are met on reassembly.

b) Vanes and nozzles, seals, and rotating elements shall be replaceable on-site.

NOTE For small and aeroderivative gas turbines, it is not unusual to remove the entire gas turbine or a major component such as the gas generator or power turbine and perform all disassembly work in a shop.

c) The package design shall incorporate lifting devices for all normal maintenance activities.

d) Proposal shall describe the special tooling, including lifting and support devices, needed for on-site repair or replacement of parts. See 9.2.3.2 m).

e) If the design requires field disassembly, the vendor drawing and data requirements (VDDR) [see Annex B, item 42 f)] shall include procedures for the disassembly required for such repair or replacement of parts.

f) Proposal shall state the duration of the maintenance activities and the number of people required to perform the work at site. See 9.2.3.2 m) and 9.2.3.2 u).

6.5.7 The uncoupled gas turbine vibration levels, on the permanent foundation, shall not exceed the uncoupled test stand acceptance criteria.

6.5.8 The coupled gas turbine vibration levels, on the permanent foundation, shall not exceed the criteria in 6.16.6.3.

6.5.9 Vendor shall provide the maximum acceptable forces and moments at each interface point (e.g. piping, ducting, supporting structure, lifting points, including during transportation, handling, and assembly at the site).

NOTE Piping misalignment, when major flanges of the equipment are unfastened, can indicate excessive forces or moments.

6.5.10 If specified, the vendor's representative shall:

• a) review and comment on the purchaser's ducting layout, piping systems, and foundations drawings;

• b) observe a check of the major field piping connections by parting the flanges;

• c) check field shaft alignment at the operating temperature;

• d) witness the initial field shaft alignment check.

6.5.11 Spare parts for the gas turbine package and all furnished auxiliaries shall meet all the criteria of this standard.

6.5.12 Proposal shall describe utility air requirements for normal operation and off design conditions (e.g. pre-start and post-shutdown). See 9.2.3.2 m).

• **6.5.13** The gas turbine package, including all auxiliaries, shall be in accordance with the specified building code (e.g. national and local).

• **6.5.14** The gas turbine package, including all auxiliaries, shall be designed for the specified transportation loads.

6.5.15 The gas turbine package when correctly aligned shall not have detrimental forces (nozzle loads or shaft displacement) when cold.

6.5.16 Mounting surfaces on machinery shall meet the following criteria.

6.5.16.1 Equipment mounting surfaces between the equipment and mounting plate shall comply with 7.3.

6.5.16.2 The upper machined or spot faced surface shall be parallel to the mounting surface.

6.5.16.3 Hold-down bolt holes shall be drilled perpendicular to the mounting surface or surfaces.

6.5.16.4 Holes shall be spot faced to a diameter suitable for a washer positioned eccentrically around the bolt.

6.5.16.5 Holes shall not be slotted.

6.5.16.6 Holes shall be 13 mm ($^1/_2$ in.) larger in diameter than the hold-down bolt.

6.6 Environmental Conditions

• **6.6.1** The gas turbine package, including all auxiliaries, shall be suitable for installation and operation under the operating environmental scenarios specified.

NOTE 1 Be careful not to specify ranges of conditions (e.g. load, temperature and humidity) that cannot happen simultaneously.

NOTE 2 The site history of environmental conditions can be used to select environmental scenarios (e.g. winter, summer, rainy season operation).

• **6.6.2** The gas turbine package, including all auxiliaries, shall be suitable for shipment and storage under the shipment environmental scenarios specified.

• **6.6.3** The gas turbine package, including all auxiliaries, shall be suitable for operation at the seismic conditions and codes specified.

• **6.6.4** The gas turbine package, including all auxiliaries, shall be suitable for operation at the wind conditions specified.

• **6.6.5** The gas turbine package, including all auxiliaries, shall be designed to maintain the mechanical integrity at the specified extreme wind conditions (e.g. cyclone, tornados) while not operating.

• **6.6.6** The gas turbine package, including all auxiliaries, shall be suitable for operation at the specified site meteorological data.

• **6.6.7** The gas turbine package, including all auxiliaries, shall be suitable for operation with the specified chemical contaminants in the air.

• **6.6.8** The gas turbine package, including all auxiliaries, shall be suitable for operation with the specified particulate contaminants in the air.

• **6.6.9** The gas turbine package, including all auxiliaries, shall not be damaged by exposure to the specified extreme minimum temperature or extreme maximum temperature. The gas turbine may need to be offline when outside the operating environmental scenarios (see 6.6.1).

NOTE Often, it is not practical to design the gas turbine to operate for all historical extreme weather conditions; therefore, compromises can be necessary.

6.7 Pressure Casings

6.7.1 For industrial gas turbines, the hoop-stress values used in the design of the casing shall not exceed the maximum allowable stress values (in tension and at the maximum operating temperature) in Section VIII, Division 2 of the ASME *BPVC*.

NOTE Aeroderivative gas turbine casings are manufactured to recognized codes of the aircraft industry, which does not necessarily conform to ASME requirements.

6.7.2 All pressure parts shall be suitable for operation at the most severe coincident condition of pressure and temperature.

6.7.3 Casing joints may be radially or axially split.

6.7.4 VDDR [see Annex B, item 42 f)] shall describe casing disassembly requirements for site maintenance.

6.7.5 All casing joints, except inlet and exhaust flange connections, shall be metal fits without gaskets.

6.7.6 All casing joints shall be tight at operating pressure and temperature with minimum perceptible leakage. Minimum perceptible leakage shall be such that it poses no health issues to personnel adjacent to the joint, no impact to the site rated power and site rated heat rate of the gas turbine, no damage to the instrumentation near the joint, nor influence the heat detection system associated with fire protection inside the gas turbine enclosure.

NOTE Using the above criteria, it can take some time for damage to appear and to identify the leakage rate as above minimal perceptible leakage.

6.7.7 Casings, supports, and baseplates shall be designed to prevent any harmful distortion that could be caused by the worst combination of allowable temperature, pressure, torque, and external forces and moments.

6.7.8 Casings shall be designed or guarded to contain all blade-off (blade-out or blade liberation) events and the subsequent collateral damage.

NOTE Disk burst and overhung shaft failures are extremely rare high-energy events and very hard and possibly impractical to contain.

6.7.9 Supports and alignment bolts shall be rigid enough to permit the machine to be moved by the use of its lateral and axial jackscrews.

NOTE Many aeroderivative gas turbines are mounted by adjustable links.

6.7.10 Each axially split casing shall allow removal and replacement of its upper half without disturbing rotor-to-casing running clearances.

NOTE Not all gas turbine casings are axially split.

6.7.11 If required for casing disassembly and reassembly, jackscrews, guide rods, and casing-alignment dowels shall be provided.

NOTE Not all gas turbines need jackscrews, guide rods, or casing-alignment dowels.

6.7.12 Guide rods shall be of sufficient length to prevent damage to the internals or studs by the casing during disassembly and reassembly.

6.7.13 Lifting provision per 7.4.3 shall be provided for lifting the top half of each horizontally split casing.

6.7.14 If jackscrews are used, as a means of parting contacting faces, one of the faces shall be relieved (counter-bored or recessed) to prevent a leaking joint or an improper fit caused by marring of the face.

6.7.15 Casing openings for inspection instruments, such as borescopes, shall be provided to permit complete inspection of all gas generator blades, turbine blades, hot gas-path components, and balance weights without pressure casing disassembly.

6.7.16 All casing inspection ports shall be stamped or tagged for identification purposes.

6.7.17 Proposal shall describe the extent of casing disassembly necessary for combustor system maintenance. See 9.2.3.2 m).

6.8 Casing Bolts

6.8.1 VDDR [see Annex B, item 42 g)] shall describe the standard used for the pressure casing bolting.

NOTE ISO 261 (metric) or ASME B1.1 (inch series) are typical for industrial gas turbine, and aeroderivative gas turbines typically use MIL-S-8879.

6.8.2 Clearance shall be provided at bolting locations to permit the use of commercially available socket or box wrenches (not special tools; see 3.1.67).

6.8.3 Internal socket-type, slotted-nut, or spanner-type bolting shall not be used unless approved by the purchaser. For limited space locations, integrally flanged fasteners may be used.

NOTE Dirt and water can accumulate in the internal cavities in bolts and nuts, leading to corrosion.

6.8.4 Studs, $^3/_8$ in. (10 mm) in diameter and larger, and bolts, $^1/_4$ in. (6 mm) in diameter and larger, shall have the material grade and manufacturer's identification symbols applied to one end. If space is inadequate, the grade symbol may be marked on one end and the manufacturer's identification symbol marked on the other end.

6.8.5 Studs shall be marked on the exposed end.

6.8.6 Set screws and washers may not have grade symbol or manufacturer's identification symbol.

NOTE A set screw is a headless screw with an internal hex opening on one end.

6.9 Casing Design for Field Balancing

6.9.1 The ducting, rotor, and casing design shall permit field balancing in the end planes of the rotors without requiring the removal of major components.

6.9.2 Rotors shall not be balanced by adding weights to coupling bolting.

6.9.3 VDDR [see Annex B, item 42 l)] shall provide procedures for field balancing.

NOTE Some multi-shaft gas turbines might not have all rotors accessible without major component removal.

6.10 Combustors

6.10.1 All combustor systems shall be provided with dual ignition. Combustor systems without cross-ignition tubes shall be provided with two igniters in each combustor.

6.10.2 For multi-fuel systems, the system shall operate on each fuel without the need for periodic fuel source switching.

6.10.3 Ports shall be included for inspection of the combustion system components, either borescope or direct visual observation.

6.10.4 VDDR [see Annex B, item 42 f)] shall include all procedures and special equipment required for combustion system inspection and maintenance.

6.11 Combustion Temperature Measurement

6.11.1 VDDR [see Annex B, item 42)] shall state the maximum permissible temperature variation in the plane of measurement, define the plane, and identify the location of the temperature sensors.

6.11.2 Each combustor shall have at least one combustion temperature sensor.

NOTE Most gas turbine combustion temperature sensors are not located in the combustor. The sensors are normally located downstream of the gas generator in the inlet to the turbine or the gas turbine exhaust diffuser outlet.

6.11.3 Each gas turbine shall have at least six combustion temperature sensors.

6.12 Fuel Injectors

6.12.1 Fuel injectors shall be removable without dismantling of the combustors.

NOTE 1 “Fuel injectors” are also known as “fuel nozzles.”

NOTE 2 Removal of the combustor or burner, in some dry low emissions (DLE) gas turbines, is needed to access and service the fuel injectors.

6.12.2 For liquid fuels, fuel injectors shall be designed to operate without erosion, plugging, and carbonization that would require service attention between scheduled maintenance intervals.

6.12.3 When multi-fuel injectors are used, proposal shall list any requirements for continuous purging and cooling of the idle nozzles. See 9.2.3.2 m).

6.12.4 Combustors and fuel injectors shall be designed and calibrated to permit random exchange of new nozzles without the need for field calibration and adjustment of flow or pressure drop.

6.13 Casing Connections

6.13.1 All piping except the gas generator and turbine casing connections shall be in accordance with 7.6.

NOTE Gas generators and turbines are standard products, as such the casing connections are defined by the gas turbine manufacturer.

6.13.2 Connections welded to the casing shall meet the material requirements of the casing, including impact values and temperature-pressure rating, rather than the requirements of the connected piping (see 6.24). All welding of connections shall be completed before the casing is hydrostatically tested.

6.13.3 Purchaser casing connections shall be at least DN 20 [nominal pipe size (NPS) $^3/_4$] and shall be either:

a) flanged;

b) machined and studded.

NOTE See 7.6 for purchaser connection details.

6.13.4 Connections and tubing on the gas generator and turbine may be gas turbine manufacturer standard.

6.13.5 Tapped openings, in ferrous casings not connected to piping, shall be plugged with solid, steel plugs.

6.13.5.1 As a minimum, these plugs shall meet the material compatibility and strength requirements of the casing.

6.13.5.2 The corrosion resistance of all plugs shall be equal or better than the casing.

6.13.5.3 Lubricant and anti-seize compound of the proper temperature specification shall be used on all threaded connections.

a) Lubricants shall not react or degrade to form hazardous compounds.

b) Calcium-based lubricants or anti-seize compounds shall not be used where temperatures can exceed 300 °C.

NOTE Compounds can react at high temperatures with alloys to form hazardous compounds (e.g. hexavalent chromium residue).

6.13.5.4 Thread tape shall not be used.

6.13.6 Mating flanges, studs, and nuts for nonstandard connections shall be supplied.

6.14 Rotating Elements

6.14.1 Shafts

6.14.1.1 Shafts shall be designed and manufactured with the capability to transmit the maximum torque that can be developed at any steady-state or transient condition in the total operating envelope.

NOTE Maximum torque typically occurs at the lowest ambient temperature.

6.14.1.2 The total operating envelope is defined by the manufacturer for the range of site operating conditions (see 6.6) and fuel compositions (see 7.9.2 and 7.9.4).

6.14.1.3 For generator drives, the vendor shall also provide the transient torque due to short circuit overloads.

6.14.1.4 For generator applications, the vendor shall provide the power limit, identify the weakest shaft element, and, if necessary, provide overload protection.

6.14.1.5 Rotor shaft design shall be one of the following:

a) stacked disks or tiebolt(s);

b) welded drum construction;

c) combination of a) and b);

d) single-piece construction.

6.14.1.6 Rotor shafts that have a finished diameter larger than 200 mm (8 in.) shall be forged steel.

6.14.1.7 Rotor shafts that have a finished diameter of 200 mm (8 in.) or less shall be forged steel or, with the purchaser's approval, hot rolled bar-stock, provided such bar-stock meets all quality and heat treatment criteria established for shaft forgings.

6.14.1.8 Rotor shaft material shall be heat-treated steel or high-strength nickel-based alloys.

6.14.1.9 Proposal shall describe the rotor shaft design. See 9.2.3.2 m).

6.14.1.10 Shaft End Design

6.14.1.10.1 For removable coupling hubs, gas turbine load shaft ends shall conform to API 671.

6.14.1.10.2 Shafts with splined shaft ends shall conform to SAE B92.1.

6.14.1.10.3 Shaft end integral hubs may be used.

6.14.1.10.4 If radial vibration and/or axial-position probes are furnished, the rotor shaft sensing areas to be observed by the probes shall conform to API 670.

6.14.1.10.4.1 The surface areas to be observed by the probes shall not be metallized, sleeved, or plated. The final surface finish shall be a maximum of 0.8 μm (32 μin.) RMS, preferably obtained by honing or burnishing.

6.14.1.10.4.2 Electrical and mechanical runout shall be determined by rotating the rotor through the full 360° supported in V-blocks or rollers at the journals while continuously recording the combined runout with a noncontacting vibration probe and measuring the mechanical runout with a dial indicator at the centerline of each probe location and one probe-tip diameter to either side.

NOTE 1 V-blocks with soft facing material are not appropriate for some rotors with high bearing unit loading.

NOTE 2 The rotor runout determined above generally cannot be reproduced when the rotor is installed in a machine with hydrodynamic bearings. This is due to pad orientation on tilt pad bearings and effect of lubrication in all journal bearings. The rotor will assume a unique position in the bearings based on the slow roll speed and rotor weight.

6.14.1.10.4.3 The shaft radial vibration sensing areas shall be properly demagnetized to the levels specified in API 670 or otherwise treated so that the combined total electrical and mechanical runout, relative to the journals, does not exceed 6 μm (0.25 mil) peak-to-peak or 25 % of the permissible vibration according to 6.16.6.2.1 to 6.16.6.2.3, whichever is less.

6.14.1.10.4.4 For areas to be observed by axial-position probes, the shaft combined total electrical and mechanical runout shall not exceed 15 μm (0.6 mil) peak-to-peak or 25 % of the permissible axial displacement, whichever is less.

NOTE See 6.14.1.10.4.2 for measurement, and see 6.16.6.2.7 and 6.16.6.2.8 for recording of mechanical and electrical runout.

6.14.1.10.4.5 If all reasonable efforts fail to achieve the limits noted in 6.14.1.10.4.4, the vendor and the purchaser shall mutually agree on alternate acceptance criteria.

6.14.2 Rotors

6.14.2.1 Gas generator rotors and rotors of single-shaft gas turbines shall be mechanically designed to safely withstand momentary speeds up to 110 % of the gas turbine trip speed settings throughout the vendor-defined firing temperature range. The proposal shall describe any inspections that would be required, before restart, after such momentary overspeed conditions have occurred. See 9.2.3.2 m).

6.14.2.2 In the event of an instantaneous loss of 100 % of site rated load and the driven inertia, gas turbine rotors shall be capable of safe operation without the blades, disks, or shafts fracturing or separating as a result of the ensuing overspeed. The proposal shall state any inspections or maintenance required before restart when overspeed excursions exceed the normal overspeed trip limits. See 9.2.3.2 m).

6.14.2.3 Each rotor shall be clearly marked with a unique identification number. This number shall be in an area that is not prone to operation or maintenance damage.

NOTE This requirement is not always possible to achieve for aeroderivative gas turbines because of their compact design.

6.14.3 Disk and Blading

6.14.3.1 The tips of rotating blades and the labyrinths of shrouded rotating blades shall be designed to allow the unit to start up at any time in accordance with the vendor's requirements.

6.14.3.2 When the design permits rubbing during normal startup, the component shall be designed to be rub tolerant and the proposal shall state if rubbing is expected. See 9.2.3.2 m).

6.14.3.3 Proposal shall describe restrictions on restarting. See 9.2.3.2 o).

6.14.3.4 Blade Natural Frequencies

6.14.3.4.1 The blade natural frequencies shall not coincide with any source of excitation from 10 % below N_{ma} to 10 % above N_{mc}.

6.14.3.4.2 Blade stress levels developed at all operating conditions (see 6.1.8) shall be low enough to allow unrestricted operation for the service life (see 6.1.2).

6.14.3.4.3 Blades shall withstand operation at resonant frequencies during normal transients (e.g. warm-up, cooldown).

6.14.3.4.4 Proposal shall list all speeds, below the N_{mc}, corresponding to blade resonances. See 9.2.3.2 m).

NOTE Excitation sources include fundamental and first harmonic passing frequencies of rotating and stationary blades upstream and downstream of each blade row, gas passage splitters, irregularities in vane and nozzle pitch at horizontal casing flanges, the first ten rotor speed harmonics, meshing frequencies in gear units, and periodic impulses caused by the combustor arrangement.

6.14.3.4.5 Gas turbine blade and disk designs (e.g. materials, cooling pattern, root design, airfoil, thermal barrier coating) shall have twice demonstrated at least 24k hour intervals of documented, continuous, trouble-free operation at similar operating conditions. The intervals may be demonstrated with either one or two different gas turbines.

• **6.14.3.4.6** If specified, the vendor shall present Campbell and Goodman diagrams for the blading, backed by demonstrated experience in the application of identical blades operating with the same source or frequency of excitation that is present in the proposed unit. The vendor shall indicate on the Goodman diagrams the standard acceptance margins.

NOTE Gas turbine manufacturers can consider Campbell diagram proprietary and show them without providing copies.

6.14.3.4.7 All Campbell diagrams shall show the blade frequencies corrected to reflect actual operating conditions. Where applicable, the diagrams for shrouded blades shall show frequencies above and below the blade lock-up speed and identify the speed at which blade lock-up occurs.

6.14.3.4.8 Proposal and VDDR [see Annex B, item 42 l)] shall describe restrictions and measures necessary to avoid windmilling or slow roll damage. See 9.2.3.2 m).

6.15 Seals

6.15.1 Replaceable or repairable sealing components (such as labyrinths, honeycombs, brush seals, or abradable surfaces) shall be provided at all gas turbine internal close-clearance points between the rotating and stationary parts to minimize the leakage of air, gas combustion products, and prevent the leakage of oil from the bearing housings.

6.15.2 The seals shall be designed so that wear occurs predominantly on the replaceable or repairable components.

6.15.3 At all external points where shafts pass through the casings, seals shall be replaceable.

6.16 Dynamics

6.16.1 General

6.16.1.1 The gas turbine manufacturer shall conduct the following rotordynamic analysis and testing, as required, during the gas turbine development or rotor system modification and submit the data or reports as requested by the purchaser. The following paragraphs, 6.16.1 through 6.16.4, are a guide to the analytical development and testing report submittals (see API TR 684-1).

NOTE Typically, gas turbine engines are designed and developed as standard products and applied to well-developed gas turbine packaged drive systems.

6.16.1.2 Rotor-bearing systems shall be designed for all potential sources of periodic forcing phenomena (excitation) including, but not limited to:

a) unbalance in the rotor system;

b) oil-film instabilities (whirl);

c) internal rubs;

d) blade, vane, nozzle, and diffuser passing frequencies;

e) gear-tooth meshing and side bands;

f) coupling misalignment;

g) loose rotor-system components;

h) hysteretic and friction whirl;

i) boundary-layer flow separation;

j) acoustic and aerodynamic cross-coupling forces;

k) asynchronous whirl;

l) ball and race frequencies of rolling element bearings; and

m) electrical line frequency.

NOTE 1 The frequency of a potential source of excitation may be less than, equal to, or greater than the rotational speed of the rotor.

NOTE 2 When the frequency of a periodic forcing phenomenon (excitation) applied to a rotor-bearing support system coincides with a natural frequency of that system, the system will be in a state of resonance. A rotor-bearing support system in resonance may have the magnitude of its normal vibration amplified. The magnitude of amplification and, in the case of critical speeds, the rate of change of the phase-angle with respect to speed, is related to the amount of damping in the system.

6.16.1.3 Resonances of structural support systems (that are within the vendor's scope of supply and that affect the rotor vibration amplitude) shall not occur within the operating speed range (see 6.1.14 and 6.1.15) or the separation margins (SMs) (see 6.16.2.14). The effective stiffness of the structural support shall be included in the analysis of the dynamics of the rotor-bearing support system [see 6.16.2.6 e)].

6.16.1.4 If structural resonances within the operating speed range or within the SMs are predicted or known (see 6.16.1.3), the vendor shall provide the operational history for the subject design. The acceptability of the subject design for the proposed service shall be contingent on purchaser approval.

NOTE Aeroderivative gas turbines often exhibit structural resonances in their operating speed range and yet operate reliably.

6.16.1.5 The vendor with unit responsibility (see Section 4) shall communicate the existence of any undesirable running speeds in the range from zero to trip speed. A list of all undesirable speeds from zero to trip shall be submitted to the purchaser for review and included in the instruction manual (see Annex B).

NOTE Examples of undesirable speeds are those caused by the rotor lateral critical speeds, system torsional critical speeds as well as blade and vane resonant modes.

6.16.2 Lateral Analysis

6.16.2.1 Critical speeds and their associated amplification factors (AFs) shall be determined by means of a damped unbalanced rotor response analysis.

6.16.2.2 The location of all critical speeds below the trip speed shall be confirmed on the test stand as required per 8.3.4.3.4. For a gas turbine with a modified bearing or rotor configuration or a gas turbine prototype, the accuracy of the analytical model shall be demonstrated as required per 6.16.2.21.

6.16.2.3 Vendor shall conduct an undamped analysis to identify the undamped critical speeds and determine their mode shapes. The analysis shall identify the first four undamped critical speeds and cover as a minimum the stiffness range to produce free-free to rigid support rotor modes. For machinery with widely varying bearing loads and/or load direction, such as overhung style machines, the vendor may substitute mode shape plots for the undamped critical speed map and list the undamped critical speed for each of the identified modes.

6.16.2.4 The results of the undamped analysis shall be furnished.

6.16.2.5 The presentation of the results shall include the following.

a) Mode shape plots (relative amplitude vs. axial position on the rotor).

b) Critical speed-support stiffness map (frequency vs. support stiffness). Superimposed on this map shall be the calculated system support stiffness, horizontal (k_x) and vertical (k_y) (see Figure 2).

NOTE The first undamped critical speed on rigid bearings is the value of the first mode at the extreme right of the critical speed-support stiffness map.

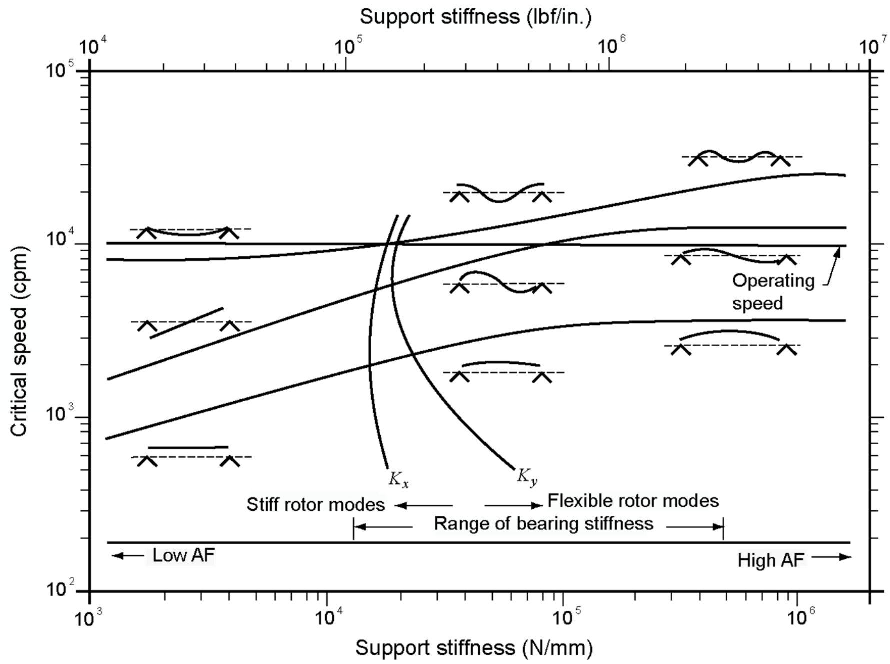


Figure 2—Undamped Critical Speed Map

6.16.2.6 The damped unbalanced response analysis shall include, but shall not be limited to, the following:

a) rotor masses and polar and transverse moments of inertia, including coupling halves, and rotor stiffness changes due to shrunk on components;

b) material properties as a function of operating temperature variation along the shaft;

c) bearing lubricant-film stiffness and damping values including changes due to speed, load, preload, range of oil inlet temperature, maximum to minimum clearances resulting from accumulated assembly tolerances, and the effect of asymmetrical loading that may be caused by gear forces (including the changes over the range of maximum to minimum torque), etc.;

d) for tilt-pad bearings, the pad pivot stiffness;

e) structure stiffness, mass, and damping characteristics, including effects of excitation frequency over the required analysis range; for machines whose dynamic structural stiffness values are less than or equal to 33.5 times the bearing stiffness values in the range from 0 % to 150 % of N_{mc}, the structure characteristics shall be incorporated as an adequate dynamic system model, calculated frequency dependent structure stiffness and damping values (impedances), or structure stiffness and damping values (impedances) derived from modal or other testing; the vendor shall state the structure characteristics values used in the analysis and the basis for these values (e.g. modal tests of similar rotor structure systems, or calculated structure stiffness values);

f) rotational speed, including the various starting-speed detents, operating speed and load ranges (including agreed upon test conditions if different), trip speed, and coast down conditions;

g) the location and orientation of the radial vibration probes, which shall be the same in the analysis as in the machine;

h) squeeze film damper mass, stiffness and damping values considering the component clearance and centering tolerance, oil inlet temperature range, and operating eccentricity;

i) for machines equipped with rolling element bearings, the vendor shall state the bearing stiffness and damping values used for the analysis; the basis for these values or the assumptions made in calculating the values shall be presented.

NOTE The above list does not address the details and product of the analysis that is covered in 6.16.2.9 and 6.16.2.12.

6.16.2.7 The supplier with unit responsibility shall provide a train lateral analysis for machinery trains with rigid couplings.

NOTE Lateral behavior of both bodies connected by a rigid coupling need to be considered together when performing any lateral rotordynamic analysis (unbalance response, undamped critical speeds, or stability).

• **6.16.2.8** If specified, a train lateral analysis shall be provided by the supplier with unit responsibility.

6.16.2.9 A separate damped unbalanced response analysis shall be conducted for each critical speed within the speed range of 0 % to 150 % of N_{mc}.

6.16.2.9.1 Unbalance shall analytically be placed at the locations that have been determined by the undamped analysis to affect the particular mode most adversely.

a) For the translatory (symmetric) modes, the unbalance shall be based on the sum of the journal static loads ($W_1 + W_2$ as shown in Figure 3) and shall be applied at the location of maximum displacement.

b) For conical (asymmetric) modes, an unbalance shall be applied at the location of maximum displacement nearest to each journal bearing. These unbalances shall be 180° out of phase and of a magnitude based on the static load on the adjacent bearing.

c) For overhung modes, the unbalances shall be based on the overhung mass.

NOTE Figure 3 shows the typical mode shapes and indicates the location and definition of U for each of the shapes.

6.16.2.9.2 The magnitude of the unbalances, U_a, shall be two times the value of U as calculated by Equation (1a) and Equation (1b).

Between Bearing Machines

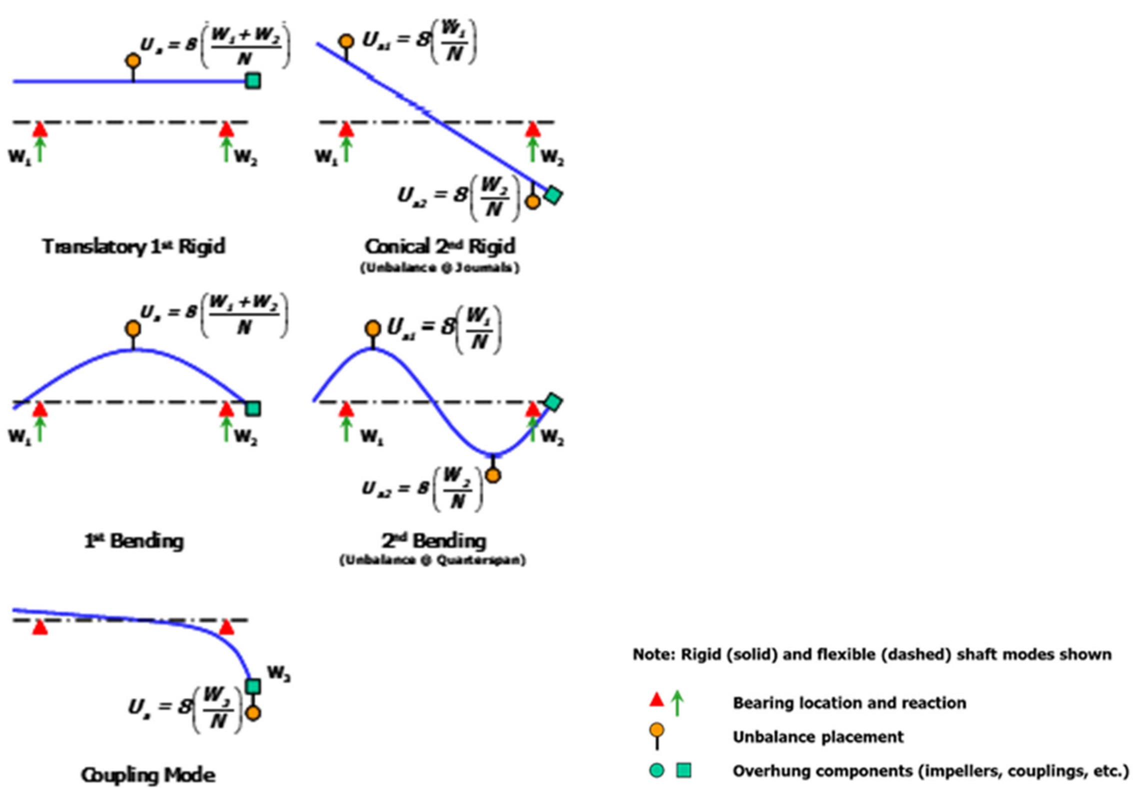


Figure 3—Typical Mode Shapes for Between Bearing Machines

In SI units:

U = 6350 W/N for N < 25k rpm (1a-1)

U = W/3.937 for N 25k rpm (1a-2)

In USC units:

U = 4 W/N for N < 25k rpm (1b-1)

U = W/6250 for N 25k rpm (1b-2)

where

U is the input unbalance for the rotordynamic response analysis, g-mm (oz-in.);

N is the maximum continuous operating speed, rpm;

W is W_1, W_2, W_3, or ($W_1 + W_2$), depending on unbalance case (see Figure 3);

W_1 and W_2 are journal static weight load (including effects of overhung mass), kg (lbm);

W_3 is the overhung mass (for bending modes where the maximum deflection occurs at the shaft ends), kg (lbm).

NOTE The limits on mass displacement are in general agreement with the capabilities of conventional balance machines and are necessary to invoke for small rotors running at speeds running above 25k rpm.

6.16.2.10 For rotors with disk(s) cantilevered beyond the journal bearings, unbalance shall be sized and placed according to Figure 4.

6.16.2.11 For rotors with disk(s) cantilevered beyond the journal bearings, each mode that is less than 150 % of maximum continuous speed shall be analyzed.

NOTE Figure 4 shows the typical mode shapes and indicates the location and definition of U for each of the shapes.

Overhung Machines

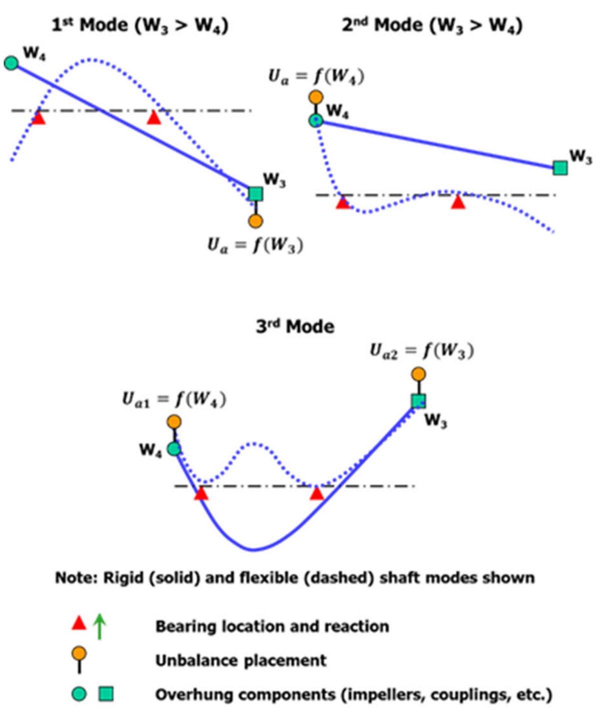


Figure 4—Typical Mode Shapes for Overhung Machines

6.16.2.12 As a minimum, the damped unbalanced response analysis shall produce the following:

a) identification of the frequency of each critical speed, regardless of the amplification factor (AF), in the range from 0 % to 150 % of N_{mc};

b) frequency, phase, and response amplitude data (Bode plots) at the vibration probe locations from 0 % to 150 % of N_{mc} for each unbalance case considered in 6.16.2.9;

c) the plot of deflected rotor shape for each critical speed resulting from the unbalances (see 6.16.2.9), showing the major-axis amplitude at each coupling plane of flexure, the centerlines of each bearing, the locations of each radial probe, and at each seal throughout the machine as appropriate; the minimum design diametral running clearance of the seals shall also be indicated;

d) additional Bode plots that compare absolute shaft motion with shaft motion relative to the bearing housing for machines where the support stiffness is less than three and a half times the oil-film stiffness.

6.16.2.13 Additional analyses shall be made for use with the verification test (see 6.16.2.21).

6.16.2.13.1 The location of the unbalance shall be determined by the vendor.

6.16.2.13.2 Any test stand parameters that influence the results of the analysis shall be included.

NOTE For some rotors, there will only be one plane readily accessible for the placement of an unbalance, e.g. the coupling flange on a single-shaft gas turbine. However, if multiple planes are available, it is possible to excite other critical speeds and multiple analyses could be necessary to avoid any detrimental effect of the unbalanced operation.

6.16.2.13.3 For coupling unbalance placement (unbalance based on the coupling half weight), the unbalance shall not be less than 16 times the value of Equation (1a) or Equation (1b), where W is the coupling half-weight and N is N_{mc}.

6.16.2.14 The damped unbalanced response analysis shall indicate that the machine will meet the following SM (see Figure 5):

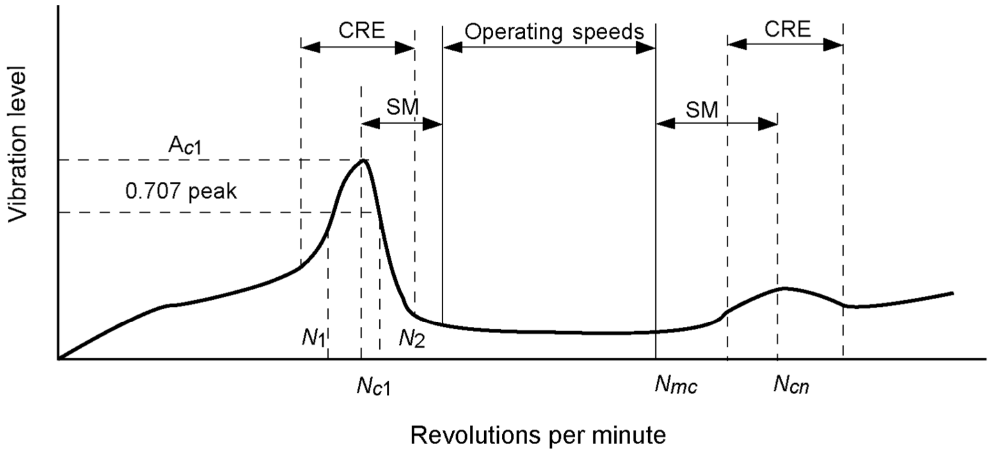
a) if the AF at a particular critical speed is less than 2.5, the response is considered critically damped and no SM is required;

b) if the AF at a particular critical speed is equal to 2.5 or greater and that critical speed is below the N_{ma}, the SM (as a percentage of the N_{ma}) shall not be less than the value from Equation (2):

$$SM = 17\left(1 - \frac{1}{AF - 1.5}\right) \tag{2}$$

c) if the AF at a particular critical speed is equal to 2.5 or greater and that critical speed is above the N_{mc}, the SM (as a percentage of the N_{mc}) shall not be less than the value from Equation (3):

$$SM = 10 + 17\left(1 - \frac{1}{AF - 1.5}\right) \tag{3}$$



N_{c1} = Rotor first critical, center frequency, cycles per minute.
N_{cn} = Critical speed, nth.
N_{mc} = Maximum continuous speed, 105%.
N_1 = Initial (lesser) speed at 0.707 x peak amplitude (critical).
N_2 = Final (greater) speed at 0.707 x peak amplitude (critical).
$N_2 - N_1$ = Peak width at the half-power point.
AF = Amplification factor.
= $\dfrac{N_{c1}}{N_2 - N_1}$
SM = Separation margin.
CRE = Critical response envelope.
A_{c1} = Amplitude at N_{c1}.
A_{cn} = Amplitude at N_{cn}.

NOTE The shape of the curve is for illustration only and does not necessarily represent any actual rotor response plot.

Figure 5—Rotor Response Plot

6.16.2.15 The calculated unbalanced peak-to-peak response at each vibration probe, for each unbalance amount and case as specified in 6.16.2.9, shall not exceed the mechanical test vibration limit, $A_{SS(p-p)}$, in 6.16.6.2.2 a). See Figure 6.

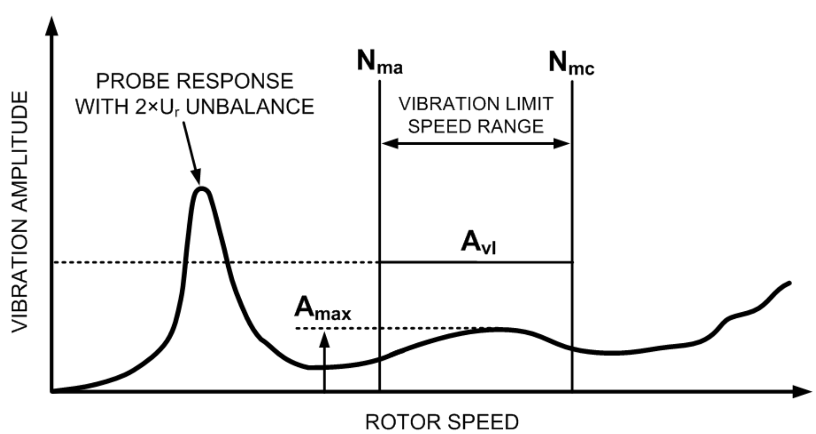


Figure 6—Plot of Applicable Speed Range of Vibration Limit

6.16.2.16 For each unbalance amount and case as specified in 6.16.2.9, the calculated major-axis, peak-to-peak response amplitudes at each close clearance location shall be multiplied by a scale factor, defined by Equation (4). The correction factor shall be between 1.0 and 6.0, inclusive.

$$S_{cc} = A_{SS(p\text{-}p)}/A_{max} \text{ or 6, whichever is less} \tag{4}$$

where

S_{cc} is scale factor for close clearance check;

$A_{SS(p\text{-}p)}$ is mechanical test vibration limit defined in 6.16.6.2.2;

A_{max} is maximum probe response amplitude (p-p) considering all vibration probes, over the range of N_{ma} to N_{mc}, for the unbalance amount/case being considered.

6.16.2.17 The calculated major-axis, peak-to-peak, unbalanced rotor response amplitudes, corrected in accordance with 6.16.2.15 at any speed from zero to trip speed shall not exceed 75 % of the minimum design diametral running clearances throughout the machine (with the exception of floating-ring seal locations). For machines with abradable seals, the response amplitude to the running clearance shall be mutually agreed. Running clearances may be different than the assembled clearances with the machine shutdown.

6.16.2.18 If the analyses indicates that either of the following requirements cannot be met:

a) the required SMs;

b) the requirements of 6.16.2.15 and 6.16.2.16;

and the purchaser and vendor have agreed that all practical design efforts have been exhausted, then acceptable amplitudes SMs and amplification factors shall be agreed.

6.16.2.19 For the unbalanced sensitivity test, the unbalance weight(s) shall be applied to most adversely excite the response peak(s) in question.

a) The magnitude of the weight(s), defined in Figure 3 or Figure 4, and the resulting measured vectorial change shall not exceed the vibration acceptance limits defined in 6.16.6.2.2 a) and the clearance check of 6.16.2.17.

b) In case it is not possible to place the unbalance weight(s) in accordance with the mode shape of the particular resonance (see 6.16.2.10), scaling shall be performed to verify that the requirements are fulfilled. The magnitude of the unbalance weight(s) shall be scaled for the mode(s) in question by the ratio between 1) the maximum modal amplitude, and 2) the modal amplitude at the balance plane where the weight is applied.

• **6.16.2.20** If specified, in addition to the other requirements of 6.16.2, the lateral analysis report shall include the following model data:

a) dimensional data of the bearing design in sufficient detail to enable calculations of stiffness and damping coefficients;

b) the weight, polar and transverse moments of inertia and center of gravity of the impellers/disk(s), blades, balance piston, shaft end seals and coupling(s) with sufficient detail to conduct an independent analysis of the rotor;

c) the mass elastic model used for the vendor's analysis;

d) the support stiffness used in the analysis and its basis;

e) for machines equipped with rolling element bearings, the vendor shall state the bearing stiffness and damping values used for the analysis and either the basis for these values or the assumptions made in calculating the values.

6.16.2.21 For a gas turbine with a modified bearing or rotor configuration or a gas turbine prototype, an unbalanced rotor response verification test shall be performed.

6.16.2.21.1 Unbalanced rotor response test results (see 8.3.4.3.7) shall be used to verify the analytical model. The actual response of the rotor on the test stand to the same arrangement of unbalance and bearing loads as was used in the analysis (see 6.16.2.13) shall be the criterion for determining the validity of the damped unbalanced response analysis. To accomplish this, the requirements of 6.16.2.21 through 6.16.2.21.4 shall be followed.

a) During the mechanical running test, the 1x operating speed amplitude and phase angle of the shaft vibration, from zero to trip speed shall be recorded.

 NOTE This set of readings is normally taken during a coast down, with convenient decrements of speed such as 50 rpm.

b) The location of critical speeds below the trip speed shall be established.

c) The unbalance that was used in the analysis performed in 6.16.2.13, multiplied by the appropriate correction factor, shall be added to the rotor in the location used in the analysis. The unbalance shall not exceed eight times the value from Equation (1a) or Equation (1b).

d) The machine shall then be brought up to the trip speed and the indicated vibration amplitudes and phase shall be recorded using the same procedure used for 6.16.2.21.1 a).

e) The corresponding indicated vibration data taken in accordance with 6.16.2.21.1 a) shall be vectorially subtracted from the results of this test.

 NOTE It is practical to store the residual unbalance (see Annex C) vibration measurements recorded in the step at 6.16.2.21.1 a) and by use of computer code perform the vectorial subtraction called for in this paragraph at each appropriate speed. This makes the comparison of the test results with the computer analysis of 6.16.2.13 quite practical. It is necessary for probe orientation be the same for the analysis and the machine for the vectorial subtraction to be valid.

f) The results of the mechanical running test, including the unbalance response verification test, shall be compared with those from the analytical model (see 6.16.2.13).

6.16.2.21.2 The vendor shall correct the model if it fails to meet either of the following criteria.

a) The actual critical speeds determined on test shall not deviate from the corresponding critical speeds predicted by analysis by more than 5 %. Where the analysis predicts more than one critical speed in a particular mode (due, for example, to the bearing characteristics being significantly different horizontally and vertically or between the two ends of the machine), the test value shall not be lower than 5 % below the lowest predicted value nor higher than 5 % above the highest predicted value.

b) If an operating speed falls between two different predicted critical speeds, these two critical speeds shall be treated separately, as if they resulted from separate modes.

 NOTE It is possible the vertical and horizontal stiffnesses are significantly different and the analysis can predict two differing critical speeds.

c) The actual major axis amplitude of peak responses from test, including those critically damped, shall not exceed the predicted values. The predicted peak response amplitude range shall be determined from the computer model based on the four radial probe locations.

6.16.2.21.3 If the support stiffness is less than two times the bearing oil film stiffness, the absolute vibration of the bearing housing shall be measured and vectorially added to the relative shaft vibration, in both the balanced [see 6.16.2.21.1 a)] and in the unbalanced [see 6.16.2.21.1 c)] condition before proceeding with 6.16.2.21.1 f). In such a case, the measured response shall be compared with the predicted absolute shaft movement.

6.16.2.21.4 After correcting the model, the requirements of 6.16.2.15 shall be confirmed.

6.16.3 Stability Analysis

6.16.3.1 For gas turbines with rotors whose N_{mc} is greater than the first undamped critical speed on rigid supports, a stability analysis shall be performed in accordance with 6.16.2.3 to 6.16.2.5. The stability analysis shall be calculated at the N_{mc}. The machine inlet and discharge conditions shall be at either the rated condition or another operating point unless the vendor and purchaser agree upon another operating point.

NOTE The Level I stability analysis (see API TR 684-1) was developed to fulfill two purposes. First, it provides an initial screening to identify rotors that do not require a more detailed study. The approach as developed is conservative. Second, the Level I analysis specifies a standardized procedure that is applied to all manufacturers similar to the lateral analysis found in 6.16.2. (Refer to API TR 684-1 for a detailed explanation of a Level I stability analysis.)

6.16.3.2 The model used in the Level I stability analysis shall include the items listed in 6.16.2.6.

6.16.3.3 All bearings shall be analyzed using the extreme values of oil inlet temperature and operating limits for clearance to produce the minimum log decrement.

6.16.3.4 When tilt pad journal bearings are used, the analysis shall be performed with synchronous tilt pad coefficients.

6.16.3.5 The anticipated cross-coupling, Q_{A}, present in the rotor is defined by the following procedures.

$$q_{\text{a}} = \frac{(HP)B_{\text{t}}C}{D_{\text{t}}H_{\text{t}}N_{\text{r}}} \tag{5}$$

Equation (5) is calculated for each stage of the rotor. Q_{A} is equal to the sum of q_{a} for all stages.

Where:

B_{t} is stage efficiency per displacement, 1.5;

C is units conversion constant, 9.55 (63);

D_{t} is blade pitch diameter, mm (in.);

H_{t} is effective blade height, mm (in.);

HP is potential maximum power per stage or impeller, W (hp);

N_{r} is normal operating speed for calculation of aerodynamic excitation, rpm;

q_{a} is cross-coupling defined in Equation (5) for each stage, kN/mm (klbf/in.);

Q_{A} is anticipated cross-coupling for the rotor, kN/mm (klbf/in.); see Equation (6);

$$Q_{\text{A}} = \sum_{i=1}^{S} q_{\text{ai}} \tag{6}$$

S is the number of stages or impellers.

6.16.3.6 An analysis shall be performed with a varying amount of cross-coupling introduced at the rotor mid-span for between bearing rotors or at the center of gravity of the stage or impeller disk(s) for single overhung rotors. For double overhung rotors, the cross-coupling shall be placed at each stage or impeller concurrently and should reflect the ratio of the anticipated cross-coupling (q_a, calculated for each impeller or stage).

6.16.3.7 The applied cross-coupling shall extend from zero to the minimum of the following:

a) a level equal to 10 times the anticipated cross-coupling, Q_A;

b) the amount of the applied cross-coupling required to produce a zero log decrement, Q_0; this value can be reached by extrapolation or linear interpolation between two adjacent points on the curve; Q_0 is the minimum cross-coupling needed to achieve a log decrement equal to zero for either minimum or maximum bearing clearance, kN/mm (klbf/in.).

6.16.3.8 A plot of the calculated log decrement, for the first forward mode shall be prepared for the minimum and maximum bearing clearances. A typical plot is presented in API TR 684-1. Q_0 and Q_A are identified as the minimum values from either bearing clearance curves.

a) Each curve shall contain a minimum of five calculated stability points.

b) The ordinate (y-axis) shall be the log decrement.

c) The abscissa (x-axis) shall be the applied cross-coupling with the range defined in 6.16.3.6.

d) For double overhung rotors, the applied cross-coupling will be the sum of the cross-coupling applied to each impeller or stage.

e) Acceptable stability exists if both of the following criteria are met, specifically:

   1) $Q_0/Q_A > 2.0$;

   2) $\delta_A > 0.1$;

where

ξ is the damping ratio;

δ is the logarithmic decrement; see Equation (7);

$$\delta = 2\Pi\xi(1-\xi^2)^{0.5} \tag{7}$$

δ_A is the minimum log decrement at the anticipated cross-coupling for either minimum or maximum bearing clearance.

6.16.3.9 If after all practical design efforts have been exhausted to achieve the requirements of 6.16.3.8, acceptable levels of the log decrement, δ_A, shall be mutually agreed upon by the purchaser and vendor.

6.16.4 Torsional Analysis

6.16.4.1 For trains including motors, generators, positive displacement units or gears, the vendor having unit responsibility shall ensure that a torsional vibration analysis of the complete coupled train is carried out and shall be responsible for directing any modifications necessary to meet the requirements of 6.16.4.6 through 6.16.4.11.

• **6.16.4.2** If specified, the supplier with unit responsibility shall perform a train torsional vibration analysis. All modifications necessary to meet the requirements of 6.16.4.6 through 6.16.4.11 shall be completed.

6.16.4.3 For packages covered in 6.16.4.1, a torsional analysis employing a simplified model (lumped rotor inertia and stiffness) and 1x excitation is sufficient.

NOTE The intent of the simplified analysis is to calculate the primary (coupling) modes of the system. Primary modes are those influenced primarily by the coupling torsional stiffness.

6.16.4.4 The torsional analyses shall include all significant excitation sources, including, but not limited to:

a) gear characteristics such as unbalance, pitch line runout, and cumulative pitch error;

b) torsional pulsations due to gear radial vibrations;

c) cyclic process impulses;

d) electrical system harmonics of mechanically connected helper motor/generator; purchaser will describe electrical system harmonics (especially for systems that include electric motors driving positive displacement machines);

e) one and two times electrical line frequency (if applicable);

f) one and two times operating speed(s).

NOTE Torsional natural frequencies can be excited from many sources.

6.16.4.5 Interferences of the primary (coupling) modes and 1x excitation frequency (mechanical or electrical) shall be at least 10 % above or 10 % below the entire operating speed range (from N_{ma} to N_{mc}; see 6.1.15 and 6.1.16).

6.16.4.6 All other interferences with torsional natural frequencies and any possible excitation frequency shall be at least 10 % above or 10 % below the entire operating speed range (from N_{ma} to N_{mc}; see 6.1.15 and 6.1.16).

6.16.4.7 When torsional resonances are calculated to fall within the margin in 6.16.4.6 (and the purchaser and vendor have agreed that all efforts to remove the critical from within the limiting frequency range have been exhausted), a steady-state stress analysis shall be performed to demonstrate that the resonances have no adverse effect on the complete train.

• **6.16.4.8** The torsional analysis shall support that the life of all shaft sections, couplings, and gear mesh exceeds the service life (see 6.1.2) by a specified service factor.

6.16.4.9 For trains with variable frequency drive (VFD) driven helper motors, vendor shall extend the analysis defined in 6.16.4.5 to 6.16.4.8 to include the following 6.16.4.9.1 to 6.16.4.9.4.

6.16.4.9.1 In addition to the excitations of 6.16.4.4, the following shall also be considered, but is not limited to:

a) integer orders of the drive output frequency;

b) sidebands of the pulse width modulation.

NOTE VFD produced broad band noise floor and feedback generated excitations can cause harmful torsional pulsations. Transient and/or mechanical/electrical coupled analyses can be required to understand the effects of these excitations.

6.16.4.9.2 A steady-state response analysis shall be performed from 0 to N_{mc} to quantify the effects of the VFD excitation of 6.16.4.9.1.

6.16.4.9.3 For interferences occurring below the minimum operating speed, an agreed upon criteria shall be used to establish acceptability of the train.

6.16.4.9.4 For interferences occurring within the operating speed range (see 6.1.15 and 6.1.16), the criteria set forth in 6.16.4.8 shall be used.

6.16.4.10 For packages with an electrical generator or helper motor, a transient short circuit fault analysis shall be performed.

6.16.4.10.1 The following fault conditions shall be considered, but are not limited to:

a) short circuits:

   1) line-to-line;

   2) two-phase;

   3) three-phase;

   4) line-to-ground;

   5) line-to-line-to-ground;

b) synchronization (generators):

   1) single-phase;

   2) three-phase.

6.16.4.10.2 For all fault conditions, the stresses in the shafting and couplings shall not exceed the low cycle fatigue limit.

NOTE Due to the timing of the torsional analysis, the vendor and purchaser need to discuss the impact of any design changes to meet the specification. The analysis for these fault conditions assumes a one-time event. Some components, as identified by the analysis, need to be replaced following the fault event.

6.16.4.11 For generators, the torsional analysis shall show that alternating torques produced by breaker re-closure have no negative impact on the service life (see 6.1.2).

6.16.5 Balancing

6.16.5.1 General

6.16.5.1.1 Rotors shall be balanced in accordance with the following procedures.

a) Rotors with rigid behavior shall be balanced at low speed in two planes per ISO 21940-11. If the first undamped critical speed on rigid supports exceeds the maximum operating speed by at least 50 %, then the rotor can normally be considered rigid for balancing purposes.

b) Rotors with flexible behavior require multiplane balancing at high-speed or low-speed balancing in stages during assembly (see ISO 21940-12). Rotors that do not satisfy the rigid rotor definition can be considered flexible for balancing purposes.

c) When a rotor with a keyway is balanced, the keyway shall be filled with a fully crowned half key, in accordance with ISO 21940-32.

6.16.5.1.2 Vendor shall submit the balancing procedure for information.

6.16.5.1.3 Balancing results shall be reported indicating which balancing method has been used, balancing weights or other corrections made (magnitude and location), residual unbalance and permissible residual unbalance.

NOTE Refer to ISO 19499 for guidance on the use and application of balancing standards.

6.16.5.2 Low-speed Balancing

6.16.5.2.1 All rotors shall be low-speed balanced.

NOTE With the use of appropriate procedures, it is often possible to balance flexible rotors at low speed so as to ensure satisfactory running when the rotor is installed in its final environment.

6.16.5.2.2 Major parts of the rotating element, such as the shaft, balancing drum, impellers or disks, shall be individually dynamically balanced before assembly, to ISO 21940, Quality Grade G 0.67 (see Figure 7).

6.16.5.2.3 The assembled rotating element shall be multiplane dynamically balanced per ISO 21940, Quality Grade G 0.67 (equivalent to 4 W/N).

NOTE See API 687, Chapter 3, Section 4.4, for special considerations for balancing tie bolt rotors.

6.16.5.2.4 The maximum allowable residual unbalance (see Annex C), U_r, per plane (journal) shall be calculated as in Equation (8a-1), (8a-2), (8b-1), or (8b-2).

In SI units:

$$U_r = 6350\ W/N \text{ for } N < 25\text{k rpm} \tag{8a-1}$$

$$U_r = W/3.937 \text{ for } N \quad 25\text{k rpm} \tag{8a-2}$$

In USC units:

$$U_r = 4\ W/N \text{ for } N < 25\text{k rpm} \tag{8b-1}$$

$$U_r = W/6250 \text{ for } N \quad 25\text{k rpm} \tag{8b-2}$$

where

U_r is the maximum allowable residual unbalance, g-mm (oz-in.);

N is the maximum continuous operating speed, rpm;

W is the journal static load, kg (lbm).

NOTE The residual unbalance requirement of this paragraph implies gas turbine life is somehow increased by balancing the rotor to this level. This, in fact, might not be the case. Gas turbine life is limited by highly stressed parts or components operating at very high temperatures. Vendor can request purchaser's approval to balance to the vendor's standard, provided that the vendor can show, by successful proven operating experience, that gas turbine life is not compromised. Typically, the unbalance is less than 15*W*/*N* or ISO 21940, Grade 2.5.

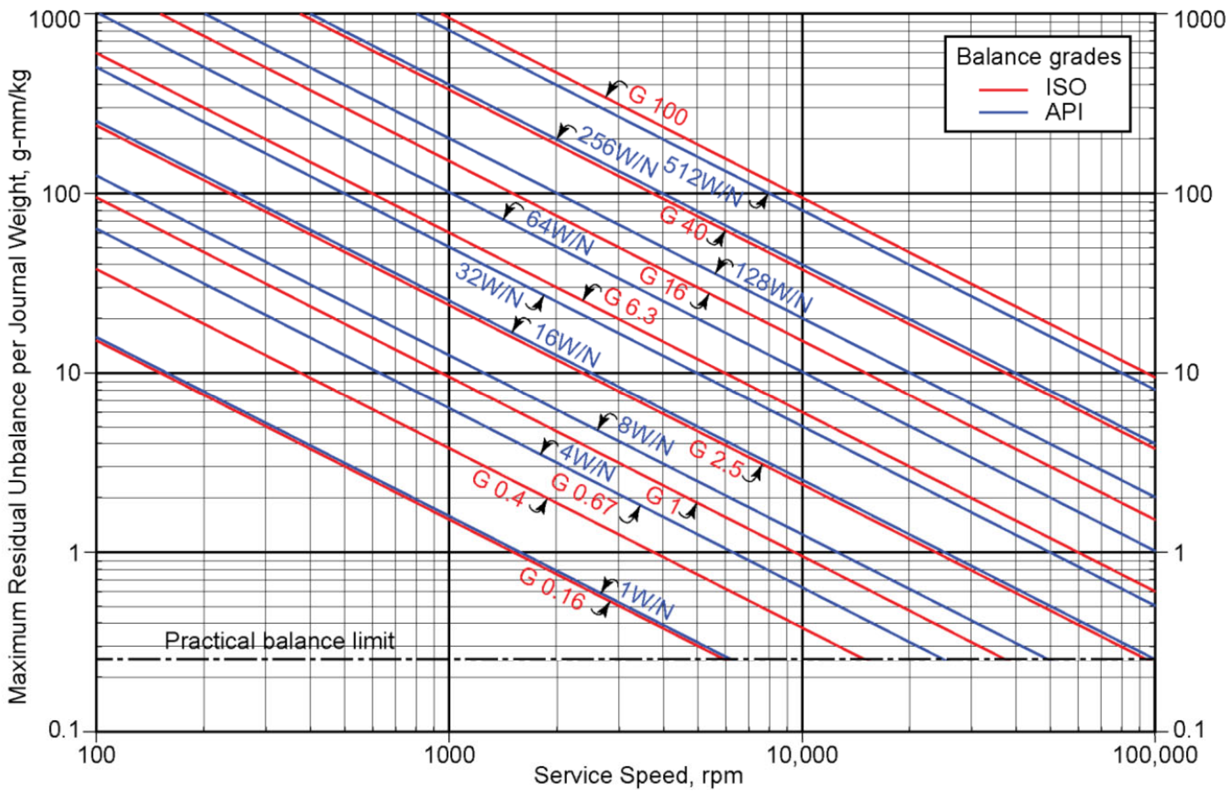


Figure 7—API and ISO Balance Grades

• **6.16.5.2.5** If specified, a low-speed residual unbalance check shall be performed and the unbalance magnitude and phase relative to each journal recorded.

NOTE This check is done to provide a reference of residual unbalance and phase for future use.

6.16.5.3 High-speed Balancing

• **6.16.5.3.1** If specified, high-speed balancing shall be performed according to procedures described in ISO 21940-12 and 6.16.5.3.4 through 6.16.5.3.16.

• **6.16.5.3.2** High-speed balancing acceptance criteria shall be according to item a), item b), or item c), as specified:

a) residual unbalance criteria according to Quality Grade G 2.5;

b) pedestal vibration derived according to the methods described in ISO 21940-12;

c) pedestal vibration of 1.0 mm/s (0.04 in./s).

6.16.5.3.3 VDDR [see Annex B, item 42 l)] shall describe the balancing procedure and the acceptance criteria for the balancing procedure required by 6.16.5.3.1.

6.16.5.3.4 The rotor shall be supported in bearings of the same type and with similar dynamic characteristics as those in which it will be supported in service.

NOTE 1 Job bearings can be used when practical.

NOTE 2 Operating speed balance units run under a vacuum. Operation in a vacuum can require the need for temporary end seals for evacuated bearings.

6.16.5.3.5 The rotor shall be completely assembled including thrust collars with locking collars and any auxiliary equipment, such as power take-off gears, overspeed trip assemblies, and tachometer rings for governor overspeed sensors.

6.16.5.3.6 The high-speed drive assembly shall be shown to have an effect less than 25 % of the balance tolerance.

NOTE In most cases, the facility drive coupling and adapter is adequate to simulate the job coupling half moment. In some cases, the job-coupling hub with moment simulator is needed, especially for the outboard ends of drive-through machines.

• **6.16.5.3.7** If specified, two orthogonally mounted, radial, noncontacting vibration probes shall be mounted next to each bearing and at a) mid-shaft or b) overhung locations.

6.16.5.3.7.1 When noncontacting vibration probes are used with a nonstandard mounting (i.e. cantilevered probe holders), structural resonance frequency of the probes and supports shall be determined after installation of the rotor and probe assemblies in the balance machine.

6.16.5.3.7.2 Noncontacting probe data shall be compensated for slow roll mechanical and electrical runout.

6.16.5.3.7.3 Noncontacting vibration probe acceptance criteria shall be agreed.

6.16.5.3.8 The appropriate pedestal rated for the rotor weight shall be used.

NOTE When using pedestal vibration as the balance criteria, pedestal stiffening is not usually engaged.

6.16.5.3.9 Prior to high-speed balancing, the complete rotor shall be balance checked at low speed in the high-speed facility. If the measured unbalance exceeds five times the maximum allowable residual unbalance for the rotor, then the cause of the unbalance shall be identified prior to high-speed balancing.

NOTE The purpose of identifying the unbalance is to increase the likelihood of the rotor successfully traversing its critical speed(s) and a successful balance.

6.16.5.3.10 Prior to balancing, the rotor residual unbalance shall be settled. This shall be accomplished by an overspeed run at a speed equal to trip speed plus 4 % of N_{mc}, hold for 3 minutes or 120 % of nominal running speed and hold for 2 minutes. After rotor settling, residual unbalance and repeatability shall be checked.

a) Record low-speed residual unbalance (amount and phase) before running up in speed.

b) Run rotor to maximum continuous operating speed and record vibration readings.

c) Repeat until readings taken in 6.16.5.3.10 a) and 6.16.5.3.10 b) are consistent.

6.16.5.3.11 Field accessible balance holes shall not be used for balance corrections.

6.16.5.3.12 Balance weights, if used, shall be compatible with disk material and suitable for the operating environment.

6.16.5.3.13 After the rotor is balanced within the tolerances of 6.16.5.3.2, repeat the final balance run with the pedestal stiffening engaged.

6.16.5.3.14 Upon completion of the balancing, Bode and polar plots for each pedestal velocity and noncontacting probe (when used) shall be provided for the initial run, stabilized rotor prior to balancing, and final balanced rotor with and without pedestal stiffening.

• **6.16.5.3.15** If specified, after the high-speed balance is completed, a low-speed residual unbalance check shall be performed and the unbalance magnitude and phase relative to each journal recorded.

NOTE This check is done to provide a reference of residual unbalance and phase for future use in a low-speed balance machine.

6.16.5.3.16 Low-speed residual unbalance checks shall be performed on a low-speed balance machine or in a high-speed balance machine capable of low-speed balance.

6.16.6 Vibration

6.16.6.1 General

6.16.6.1.1 Steady-state radial vibration at rated speed shall not exceed the limits in Table 1, Zone A.

NOTE ISO 20816-1 and ISO 20816-4 give guidelines for applying evaluation criteria for shaft vibration under normal conditions, measured at or close to the bearings of gas turbine sets.

6.16.6.1.2 Steady-state radial and axial vibration at rated speed shall not exceed the limits in Table 1, Zone A.

NOTE ISO 20816-1 and ISO 20816-4 give specific guidance for assessing the severity of vibration measured on the bearing housings or pedestals of industrial gas turbine-driven sets.

6.16.6.1.3 The evaluation criteria in ISO 20816-1 and ISO 20816-4 are based on the following evaluation zones.

a) Zone A—The vibration of newly commissioned machines would normally fall within this zone.

b) Zone B—Machines with vibration within this zone are normally considered acceptable for unrestricted long-term operation.

c) Zone C—Machines with vibration within this zone are normally considered unsatisfactory for long-term continuous operation. Generally, the machine may be operated for a limited period in this condition until a suitable opportunity arises for remedial action.

d) Zone D—Vibration values within this zone are normally considered to be of sufficient severity to cause damage to the machine.

6.16.6.1.4 The vibration criteria provided in ISO 20816-4 shall apply to industrial gas turbines and free power turbines covering the power range above 1 MW and a speed range under load between 2k rpm and 25k rpm. Aeroderivative gas generators are excluded from this vibration criteria.

NOTE The 1 MW power limit for API 616 is less than the 3 MW limit in ISO 20816-4.

Table 1—Vibration Limits According to ISO 20816-4

Zone	**Bearing Housing Pedestal Criteria Vibration Limits** mm/s RMS (in./s RMS)	**Shaft Relative Vibration Limits** $A_{(P-P)}$ µm (mils)
A	≤ 4.5 (0.18)	≤ 4800/ N (190/ N)
B	4.5 to 9.3 (0.18 to 0.37)	4800/ N to 9000/ N (190/ N to 360/ N)
C	9.3 to 14.7 (0.37 to 0.58)	9000/ N to 13,200/ N (360/ N to 525/ N)
D	14.7 (0.58)	13,200/ N (525/ N)

6.16.6.2 Vibration Measured During Factory Test

6.16.6.2.1 Acceptance criteria for gas turbines with hydrodynamic bearings, during the mechanical running test, shall be based on shaft vibration or on bearing housing vibration. If casing vibration will be substituted for bearing housing vibration, the location of sensors and acceptance criteria shall be agreed with the purchaser before purchase.

6.16.6.2.2 During steady-state operation, operating at N_{mc} or at any other speed within the entire operating speed range (see 6.1.15 and 6.1.16), the vibration shall not exceed the following values.

a) Shaft relative vibration [$A_{\text{(ss)}}$] for Zone A in ISO 20816-4 is in Equation (9a) or Equation (9b).

In SI units:

$$A_{\text{ss (p-p)}} = \left(\frac{4800}{\sqrt{N}}\right) - 12.5 \quad \mu\text{m} \tag{9a}$$

In USC units:

$$A_{\text{ss (p-p)}} = \left(\frac{190}{\sqrt{N}}\right) - 0.5 \quad \text{mils} \tag{9b}$$

where

$A_{\text{ss (p-p)}}$ is the magnitude of unfiltered vibration, μm (mils) peak-to-peak;

N is the maximum continuous operating speed, rpm.

b) Bearing housing vibration for Zone A in ISO 20816-4 is 4.5 mm/s (0.18 in./s) RMS, broadband.

6.16.6.2.3 The RMS measurement is broadband vibration over a frequency range from 10 Hz to at least 500 Hz or six times the maximum normal operating speed, whichever is greater.

6.16.6.2.4 During steady-state operation, operating between N_{ma} and N_{mc} (see 6.1.15 and 6.1.16), the total unfiltered bearing housing vibration shall not exceed 2.5 mm/s (0.1 in./s) zero-to-peak (0-p).

6.16.6.2.5 At any speed greater than the N_{mc}, up to and including the trip speed of the driver, the vibration magnitude shall not increase, more than the values listed below, above the maximum value recorded at the N_{mc}:

a) 12.7 μm (0.5 mil) for shaft relative vibration where acceptance criteria were displacement;

b) 1.5 mm/s (0.06 in./s) for bearing housing vibration where acceptance criteria were velocity.

6.16.6.2.6 Any nonsynchronous discrete vibration shall not exceed 20 % of the synchronous vibration magnitude. These limits are not to be confused with the limits in 6.16.2.21 for shop verification of unbalanced response.

6.16.6.2.7 Accurate records of electrical and mechanical runout, for the full 360° at each probe location, shall be included in the mechanical test report.

6.16.6.2.8 If the vendor can demonstrate that electrical or mechanical runout is present, a maximum of 25 % of the allowable vibration calculated from Equation (10a) or 15 μm [Equation (10b) or 0.6 mil], whichever is less, can be vectorially subtracted from the vibration signal measured during the factory test.

6.16.6.3 Vibration Measured in the Field (In Situ)

6.16.6.3.1 Acceptance criteria for commissioning shall be based on shaft vibration or on bearing housing vibration as determined by the vendor.

6.16.6.3.2 The following limits shall apply to vibration measurements under steady-state operating conditions at rated speeds.

a) Shaft relative vibration.

In SI units:

$$A_{\text{is (p–p)}} = 1.5 \times A_{\text{ss}}\ \mu\text{m} \tag{10a}$$

In USC units:

$$A_{\text{is (p–p)}} = 1.5 \times A_{\text{ss}}\ \text{mils} \tag{10b}$$

where

$A_{\text{is (p–p)}}$ is the magnitude of unfiltered vibration, μm or mils, peak-to-peak in situ;

$A_{\text{ss (p–p)}}$ is the magnitude of unfiltered vibration, μm or mils, peak-to-peak during shop test.

Or

b) Bearing housing vibration: 6.5 mm/s (0.25 in./s) RMS, broadband.

6.16.6.3.3 The RMS measurement shall be a broadband vibration over a frequency range from 10 Hz to at least 500 Hz or six times the maximum normal operating speed, whichever is greater.

6.17 Bearings and Bearing Housing

6.17.1 General

6.17.1.1 Vendor shall provide their standard bearing design. Proposal shall include bearing description [see 9.2.3.2 m)]. Hydrodynamic radial and thrust bearings are preferred. It is recognized, however, that certain classes of gas turbines are designed to use rolling element bearings.

6.17.1.2 Bearings shall have sufficient ultimate load capability to withstand forces resulting from failure of any gas turbine component that requires immediate shutdown (such as loss of a blade) in order to prevent excessive secondary damage to the gas turbine.

6.17.1.3 Oil temperature rise through each bearing shall not exceed 33 °C (60 °F) under the most adverse operating conditions (see 6.6).

6.17.1.4 If design inlet oil temperature exceeds 50 °C (122 °F), special consideration shall be given to bearing design, oil flow and viscosity, and allowable temperature rise.

6.17.2 Rolling Element Bearings

6.17.2.1 Bearing detail and installation design for each bearing location shall be based on a load-life analysis, which as a minimum, shall provide for consideration of the following:

a) rotor weight reactions;

b) vibratory loading;

c) preloading;

d) misalignment;

e) gear loads;

f) combined thrust and radial loads;

g) off-design point loads;

h) surge loading of gas generator.

6.17.2.2 Bearing load rating and calculation methods shall meet or exceed the requirements of ABMA 9 for ball bearings and ABMA 11 for roller bearings.

6.17.2.3 Bearing installation and mounting practices shall conform to the applicable ABMA standards.

6.17.2.4 Bearing tolerances shall not exceed the applicable standards for the class for the application and as defined in Section 3 of both ABMA 7 and ABMA 11.

6.17.2.5 Bearings shall be selected to meet an L10 rated life of 50k hours continuous operation at ISO continuous rating conditions and 32k hours at maximum axial and radial loads and rated speed.

6.17.2.6 The basic rating L10 life shall be calculated in accordance with ISO 281.

6.17.2.7 Velocity probes shall be provided and mounted to the gas turbine casing.

6.17.3 Hydrodynamic Radial Bearings

6.17.3.1 Hydrodynamic radial bearings shall be:

a) split, for ease of assembly;

b) precision bored;

c) sleeve or pad type;

d) steel backed;

e) equipped with anti-rotation pins and shall be positively secured in the axial direction.

6.17.3.2 Hydrodynamic radial bearings shall have Babbitted replacement liners, pads, or shells.

6.17.3.3 The bearing design shall suppress hydrodynamic instabilities and provide sufficient damping over the entire range of allowable bearing clearances to limit rotor vibration to the maximum amplitudes (see 6.16.2.16) while the equipment is operating loaded or unloaded at any speed between N_{ma} and N_{mc}.

6.17.3.4 The liners, pads, or shells shall be in axially split bearing housings and shall be replaceable with minimal dismantling of any portion of the casing.

6.17.3.5 Bearings shall be designed to prevent incorrect positioning.

• **6.17.3.6** If specified, the Babbitt to backing material minimum contact shall be greater than 99 % as inspected by ultrasonic testing for bond and dye penetrant testing for side separation per ISO 4386-1.

6.17.4 Thrust Bearings

6.17.4.1 Thrust bearings shall be arranged to allow axial positioning of each rotor relative to the casing and setting of the bearings clearance.

6.17.4.2 Thrust bearings shall be sized for continuous operation through the full operating range including the most adverse operating conditions (see 6.6).

6.17.4.3 Calculation of the thrust load shall include but shall not be limited to the following factors:

a) fouling and variation in seal clearances at design and at twice the design internal clearance;

b) step thrust from all diameter changes;

c) stage reaction and stage differential pressure;

d) variations in inlet, bleed, injection, and exhaust conditions;

e) external loads from the driven equipment, as described in 6.17.4.4 through 6.17.4.6.

6.17.4.4 For gear-type couplings, the external thrust force shall be calculated from Equation (11a) and (11b).

In SI units:

$$F = [0.25 \times 9550 \times P_r]/(N_r \times D) \tag{11a}$$

In USC units, this translates to:

$$F = [0.25 \times 63{,}000 \times P_r]/(N_r \times D) \tag{11b}$$

where

F is the external thrust force, kN (lbf);

0.25 is the applied coefficient friction of gear teeth friction;

P_r is the potential maximum power, kW (hp);

N_r is the rated speed, rpm;

D is the shaft diameter at the coupling, mm (in.).

Shaft diameter is used to approximate gear coupling pitch diameter.

6.17.4.5 Thrust forces from metallic flexible-element couplings shall be calculated on the basis of the maximum allowable deflection permitted by the coupling manufacturer.

6.17.4.6 If two or more rotor thrust forces are to be carried by one thrust bearing (such as in a gear box), the resultant of the forces shall be used provided the directions of the forces make them numerically additive; otherwise, the largest of the forces shall be used.

6.17.5 Hydrodynamic Thrust Bearings

6.17.5.1 Hydrodynamic thrust bearings shall be:

a) steel-backed, Babbitted, multi-segment type;

b) designed for the maximum thrust on the active side;

c) arranged for continuous pressurized lubrication;

d) tilting-pad type on the active side(s); tilting-pad type shall ensure that each pad carries an equal share of the thrust load with minor variation in pad thickness;

e) self-equalizing for active side(s).

6.17.5.2 If tilt-pad bearings are used for both the active and inactive sides of the thrust bearing, both sides shall use the same size and type of tilt-pad bearing.

6.17.5.3 Each pad shall be designed and manufactured with dimensional precision (thickness variation) that will allow the interchange or replacement of individual pads.

6.17.5.4 Hydrodynamic thrust bearings should use integral thrust collars.

6.17.5.5 For integral collars, they shall be provided with at least 3.0 mm ($^1/_8$ in.) of additional stock to enable refinishing if the collar is damaged.

6.17.5.6 For replaceable collars (for assembly and maintenance purposes), they shall be positively locked to the shaft to prevent fretting.

6.17.5.7 Both faces of the thrust collars for hydrodynamic thrust bearings shall have a surface finish of 0.4 µm (16 µin.) R_a or better and after mounting, the axial total indicated runout of either face shall not exceed 13 µm (0.0005 in.).

6.17.5.8 Hydrodynamic thrust bearings shall be selected such that under any operating condition the load does not exceed 50 % of the bearing manufacturer's ultimate load rating at potential maximum power.

NOTE The ultimate load rating is the load that will produce the minimum acceptable oil-film thickness without inducing failure during continuous service or the load that will not exceed the creep-initiation or yield strength of the Babbitt at the location of maximum temperature on the pad, whichever load is less.

6.17.5.9 Thrust bearings shall be selected such that under any operating condition the load does not exceed 50 % of the bearing manufacturer's ultimate load rating. The ultimate load rating is the load that will produce the minimum acceptable oil-film thickness without inducing failure during continuous service or the load that will not exceed the creep-initiation or yield strength of the Babbitt at the location of maximum temperature on the pad, whichever load is less.

6.17.5.10 In sizing thrust bearings, consideration shall be given to the following for each specific application:

a) the shaft speed;

b) the temperature of the bearing Babbitt;

c) the deflection of the bearing pad;

d) the minimum oil-film thickness;

e) the feed rate, viscosity, filtration levels, and supply temperature of the oil;

f) the design configuration of the bearing;

g) the Babbitt alloy;

h) the turbulence of the oil film;

i) potential maximum power;

j) pad material.

• **6.17.5.11** If specified, the Babbitt to backing material minimum contact shall be greater than 99 % as inspected by ultrasonic testing for bond and dye penetrant testing for side separation per ISO 4386-1.

6.18 Bearing Housings

6.18.1 Bearing housings for pressure-lubricated hydrodynamic bearings shall minimize foaming.

6.18.2 The drain system shall be adequate to maintain the oil and foam level below shaft end seals.

6.18.3 Bearing housings shall be equipped with replaceable labyrinth-type end seals and deflectors where the shaft passes through the housing. Lip-type seals shall not be used.

6.18.4 The end seals and deflectors shall be made of spark-resistant materials.

6.18.5 The design of the end seals and deflectors shall effectively retain oil in the housing and prevent entry of foreign material into the housing.

6.18.6 Bearing housings for hydrodynamic bearings shall have two radial-vibration (e.g. X and Y directions) probes in each bearing housing.

6.18.7 Bearing housings for hydrodynamic bearings shall have two axial-position probes at the thrust end of each rotor that has a thrust bearing.

6.18.8 One-event-per-revolution probe shall be provided in each rotor.

6.18.9 All vibration probes, position probes and one-event-per revolution probe installations shall conform to API 670.

6.18.10 Axially split bearing housings shall have a metal-to-metal split joint whose halves are located by means of dowels.

6.18.11 Unless otherwise specified, hydrodynamic thrust bearings and radial bearings shall be fitted with bearing-metal temperature sensors installed in accordance with API 670.

6.19 Lubrication

6.19.1 Unless otherwise specified, hydrodynamic bearings shall be designed for oil lubrication using an ISO 3448 viscosity grade (VG) 32 or 46 mineral oil in accordance with ASTM D4304 or ISO 8068 type AR.

NOTE Oil VG selection is influenced by site ambient temperature.

6.19.2 Hydrodynamic bearings shall be designed for the same oil as the driven equipment.

• **6.19.3** If specified, or required by the vendor, a synthetic lubrication oil shall be used.

NOTE Most aeroderivative turbines require synthetic oil.

6.19.4 Proposal shall provide a complete description of the lubrication system(s) and lubricant specifications. See 9.2.3.2 m).

• **6.19.5** All materials used in the construction of the lubrication system shall be compatible with the lubricants specified by either the purchaser or the vendor.

• **6.19.6** If specified, the lube oil system shall be in accordance with API 614.

NOTE Purchaser uses API 614 to describe the lube oil system and whether gas turbine and driven equipment systems are separated or combined.

6.19.7 Unless otherwise specified, the gas turbine oil system shall be furnished to supply oil at a suitable flow, temperature, and pressure(s) to the entire train (including all bearings, lubricated couplings, governing and control-oil systems).

NOTE The lubrication system is normally an integral part of the gas turbine package.

6.19.8 Where oil is supplied from a common system to two or more components of a machinery train (e.g. compressor, gear, gas turbine), the vendor having unit responsibility shall ensure compatibility of type, grade, pressure, temperature, and flow rate of oil for all equipment served by the common system.

6.20 Materials

6.20.1 Materials of construction shall be suitable for the operating and site environmental conditions (see 6.6).

NOTE Typical agents of concern in air or fuel are hydrogen sulfide, amines, chlorides, bromides, iodides, cyanides, fluorides, naphthenic acid, and polythionic acid. Other agents affecting elastomeric selection include ketones, ethylene oxide, sodium hydroxide, methanol, benzene, and solvents.

6.20.2 Gas turbine materials of construction shall be selected by the gas turbine manufacturer for the site operating conditions (see 6.6), except as required or prohibited by datasheets or this standard (see 7.6.1 for requirements for auxiliary piping materials).

6.20.3 Proposal shall summarize all the materials of construction and coatings for all systems that contact the combustion air, fuel(s) or exhaust (see 9.2.3.2 m).

6.20.4 Proposal shall list all the materials of construction and coatings for all major gas turbine package components (see 9.2.3.2 m).

6.20.5 Proposal shall describe any reduction in service life (see 6.1.2) due to the fuel composition (see 7.9.2 and 7.9.4) or environment (see 6.6) (see 9.2.3.2 m).

6.20.6 Proposals shall identify materials by reference to applicable international standards, including the material grade. When no such designation is available, the vendor's material specification, material properties, chemical composition, and test requirements shall be included.

NOTE Some materials could be proprietary.

6.20.7 Proposal shall identify all components, materials, or coatings that do not have at least 24k hours total fleet experience and at least 8k hours on one gas turbine (see 9.2.3.2 m). To qualify, the gas turbine availability during the experience times has to be 95 % or higher.

6.20.8 Proposal shall list optional tests and optional inspection procedures that could ensure that materials are satisfactory for the service (see 9.2.3.2 m).

NOTE This allows the purchaser to be informed about and select optional tests or procedures.

6.20.9 External parts (e.g. control linkage joints, adjustment mechanisms) that are subject to movement (e.g. rotary or sliding motion) shall be corrosion-resistant materials (base material or coatings) suitable for the site environment and service life.

6.20.10 Minor parts that are not identified (such as nuts, springs, washers, gaskets, and keys) shall have corrosion resistance (base material or coatings) at least equal to that of the major components in the same environment.

6.20.11 If austenitic stainless steel parts exposed to conditions that may promote intergranular corrosion are to be fabricated, hard faced, overlaid, or repaired by welding, they shall be made of low-carbon grades or stabilized grades.

NOTE Overlays or hard surfaces that contain more than 0.10 % carbon can sensitize both low-carbon and stabilized grades of austenitic stainless steel unless a buffer layer that is not sensitive to intergranular corrosion is applied.

6.20.12 Where mating parts such as studs and nuts of austenitic stainless steel or materials with similar galling tendencies are used, they shall be lubricated with an anti-seize compound compatible with the expected temperatures, fluids, and environment (see 6.6).

• **6.20.13** If hydrogen sulfide has been identified in any fluid (see 7.9.1.1.2 and 6.6.7), materials exposed to that fluid shall be selected and processed in accordance with the requirements of NACE MR0103 or NACE MR0175, as specified.

6.20.14 Vendor shall select materials to avoid conditions that may result in electrolytic corrosion. Where such conditions cannot be avoided, the purchaser shall agree on the material selection and any other precautions necessary.

NOTE When dissimilar materials, with significantly different electrical potentials, are in contact, in the presence of an electrolytic solution, galvanic couples can result in serious corrosion of the less noble material. The NACE *Corrosion Engineer's Reference Book* is one resource for selection of suitable materials in these situations.

6.20.15 Materials, casting factors, and the quality of any welding shall be equal to those required by Section VII and IX, of the ASME *BPVC*. The manufacturer's data report forms, required by the *BPVC*, are not required.

NOTE For impact test requirements refer to 6.25.

6.20.16 Only fully killed, normalized steels made to fine-grain practice shall be used. Steel made to a course austenitic grain size practice (such as ASTM A515) shall not be used.

NOTE Low-carbon steels can be notch sensitive and susceptible to brittle fracture at ambient or lower temperatures.

• **6.20.17** If specified, the following alloy steel items shall be subject to positive material identification (PMI) testing before gas turbine assembly:

a) the pressure casing of rotating equipment;

b) shafts;

c) blading and shrouds;

d) locking pins used to secure stationary vanes;

e) disks of built-up rotors;

f) tie bolts;

g) locking nuts on built-up rotors;

h) shaft sleeves;

i) alloy claddings and weld overlays;

j) pressure casing joint bolting (studs and nuts);

k) inlet guide vanes;

l) gas turbine nozzles;

m) balance pistons;

n) other purchaser-described piping, fabrications, welds, materials, etc.

6.20.18 Mill test reports, material composition certificates, visual stamps, or markings shall not be substitutes for PMI testing.

6.20.19 PMI shall not be a substitute for mill test reports, material composition certificates, visual stamps, or markings.

6.20.20 PMI results shall be within the governing material standard limits allowing for the measurement uncertainty (inaccuracy) of the PMI device manufacturer.

6.20.21 Unless otherwise specified, nondestructive examination (NDE) of materials shall be in accordance with Section V of the ASME *BPVC* (see also 8.2.2.1).

NOTE The Pressure Equipment Directive (2014/68/EU) has additional NDE requirements beyond those of ASME.

6.20.22 PMI shall use techniques providing quantitative results.

NOTE 1 PMI test methods are intended to identify alloy materials and are not intended to establish the exact conformance of a material to an alloy specification.

NOTE 2 Additional information on PMI testing can be found in API 578.

NOTE 3 PMI confirms the correct materials are used in component manufacturing, fabrication, and assembly.

6.21 Bolting

6.21.1 For casing pressure joints, bolting material shall be, as a minimum, in accordance with ASTM A193/A193M, Grade B7.

6.21.2 Carbon steel nuts shall be in accordance with ASTM A194/A194M, Grade 2H, where space is limited, case hardened carbon steel nuts in accordance with ASTM A563 Grade A may be used.

6.21.3 For temperatures below –30 °C (–20 °F), bolting material in accordance with ASTM A320/A320M shall be used.

6.22 Castings

6.22.1 Cast iron castings shall, as a minimum, conform to ASTM A395/A395M.

6.22.1.1 A minimum of one set (three samples) of Charpy V-notch impact specimens at one-third the thickness of the test block shall be made from the material adjacent to the tensile specimen on each keel or Y-block.

6.22.1.2 All three specimens shall have an impact value not less than 12.0 J (9 ft-lbf), and the mean of the three specimens shall not be less than 14 J (10 ft-lbf) at room temperature.

6.22.1.3 The keel or Y-block cast at the end of the pour shall have a thickness not less than the thickness of critical sections of the main casting.

6.22.1.4 This test block shall be tested for tensile strength and hardness and shall be microscopically examined.

6.22.1.5 Classification of graphite nodules under microscopic examination shall be in accordance with ASTM A247 or other internationally recognized standards approved by the purchaser.

6.22.1.6 There shall be no intercellular flake graphite.

NOTE 1 Critical sections are typically heavy sections, section changes, high-stress points, and flanges. Normally, bosses and similar sections are not considered critical sections of a casting. If critical sections of a casting have different thicknesses average size keel or Y-blocks can be selected in accordance with ASTM A395/A395M.

NOTE 2 ASTM A395/A395M requires the microstructure of Grade 60-40-18 nodular iron to be essentially ferritic, contain no massive carbides, and have a minimum of 90 % Type I and Type II Graphite nodules as in Figure 1 or Plate I of Test Method A247.

NOTE 3 ASTM A395/A395M requires the microstructure of Grade 60-45-15 nodular iron to be 45 % pearlitic, maximum, contain no massive carbides, and have a minimum 90 % Type I and Type II Graphite nodules as in Figure 1 or Plate I of Test Method A247.

6.22.1.7 Integrally cast test bosses, preferably at least 25 mm (1 in.) in height and diameter, shall be provided at critical areas of casting for subsequent removal for the purposes of hardness testing and microscopic examination.

6.22.1.8 An as-cast sample from each ladle shall be chemically analyzed.

6.22.1.9 Brinell hardness tests shall be made on the actual castings at extremity locations that represent the sections poured first and last and other feasible critical sections such as section changes and flanges.

6.22.1.10 Sufficient surface materials shall be removed before hardness tests are made to eliminate any skin effects.

6.22.2 Castings shall be free from harmful defects (e.g. porosity, hot tears, shrink holes, blow holes, cracks, scale, blisters).

6.22.3 Surfaces of castings shall be cleaned by sandblasting, shot blasting, chemical cleaning, or any other standard methods.

6.22.4 Mold-parting fins and the remains of gates and risers shall be chipped, filed, or ground flush.

6.22.5 The use of chaplets in pressure castings shall be held to a minimum. Chaplets shall be clean and corrosion free (plating of chaplets is permitted) and of a composition compatible with the casting.

6.22.6 Pressure-containing ferrous castings shall not be repaired, except as described below.

6.22.6.1 Weldable grades of steel castings shall be repaired by welding using a qualified welding procedure based on the requirements of Section VIII, Division 1, and Section IX of the ASME *BPVC* or other internationally recognized standard as approved by the purchaser.

6.22.6.2 After major weld repairs and before hydrotest, the complete repaired casting shall be given a post-weld heat treatment to ensure stress relief and continuity of mechanical properties of both weld and parent metal and dimensional stability during subsequent machining operations. Major repair is any defect that equals or exceeds any of the three criteria defined below:

a) the depth of the cavity prepared for repair welding exceeds 50 % of the component wall thickness;

b) the length of the cavity prepared for repair welding is longer than 150 mm (6 in.) in any direction;

c) the total area of all repairs to the part under repair exceeds 10 % of the surface area of the part.

6.22.6.3 If defects in iron castings exist and are within allowed repair limits of ASTM A395/A395M, plugging is an acceptable repair method. The holes drilled for plugs shall be carefully examined, using liquid penetrant, to ensure that all defective material has been removed.

6.22.6.4 All repairs that are not covered by the agreed material specification shall be subject to the purchaser's approval.

6.22.7 Fully enclosed cored voids, which become fully enclosed by methods such as plugging, welding, or assembly, shall not be used.

6.22.8 Gas generator and turbine casting repairs, performed at the foundry or factory shall be described in VDDR [see Annex B, item 30)].

6.23 Forgings

Compressor disk and turbine disk forgings shall have transition temperatures (at the bore sections) that are below minimum ambient temperatures (see 6.6).

6.24 Welding

6.24.1 Welding of piping, rotating parts and other highly stressed parts, weld repairs and any dissimilar-metal welds shall be performed and inspected by operators and procedures qualified in accordance with Section VIII, Division 1, and Section IX of ASME *BPVC* or purchaser-approved standard such as EN ISO 9606-1 for weld qualifications or procedures.

6.24.2 Vendor shall be responsible for the review of all repairs and repair welds to ensure that they are properly heat treated and nondestructively examined for soundness and compliance with the applicable qualified procedure (see 6.20.15).

6.24.3 Unless otherwise specified, all welding other than that covered by Section VIII, Division 1, of the ASME *BPVC* and ASME B31.3, such as welding on baseplates, nonpressurized ducting, lagging, and control panels, shall be performed in accordance with AWS D1.1/D1.1M, as a minimum. Proposal shall identify if an alternate code is to be used. See 9.2.3.2 m).

6.24.4 Repair welds shall be nondestructively tested by the same method used to detect the original flaw. As a minimum, this shall be in accordance with 8.2.2.4 for magnetic material, and by the liquid penetrant method in accordance with 8.2.2.5 for nonmagnetic material.

6.24.5 Pressure-containing casings made of wrought materials or combinations of wrought and cast materials shall be as follows.

6.24.5.1 Before welding, plate edges shall be examined by either magnetic particle method (magnetic materials) or dye penetrant method (nonmagnetic materials) to confirm the absence of laminations.

6.24.5.2 Accessible surfaces of welds shall be inspected by magnetic particle or liquid penetrant examination after back chipping or gouging and again after post-weld heat treatment.

6.24.5.3 The quality control of welds that will be inaccessible on completion of the fabrication shall be as approved by the purchaser prior to fabrication.

6.24.5.4 Pressure-containing welds, including welds of the case to axial and radial joint flanges, shall be full-penetration welds.

6.24.5.5 Casings fabricated from material that, according to internationally recognized standards such as Section VIII, Division 1, of the ASME *BPVC*, requires post-weld heat treatment shall be heat treated regardless of thickness.

6.24.6 Connections welded to pressure casings shall be installed as follows.

• **6.24.6.1** If specified, all welds shall have the specified inspection (radiography, magnetic particle inspection, or liquid penetrant inspection). This is in addition to the requirements of 6.24.1.

6.24.6.2 Auxiliary piping welded to chromium-molybdenum alloy steel or 12 % chrome steel components shall be of the same material, except that chromium-molybdenum alloy steel pipe may be substituted for 12 % chrome steel pipe.

6.24.6.3 Post-weld heat treatment, when required, shall be carried out after all welds, including piping welds, have been completed.

• **6.24.6.4** If specified, proposed connection designs shall be submitted for approval before fabrication. The drawing shall show weld design, size, materials, and pre-weld and post-weld heat treatments.

6.24.6.5 All welds shall be heat treated in accordance with internationally recognized standards such as Section VIII, Division 1, UW-10 and UW-40, of the ASME *BPVC*.

6.25 Impact Test Requirements

6.25.1 To avoid brittle failures, materials and construction for low-temperature service shall be suitable for the minimum design metal temperature and concurrent pressure. The purchaser and the vendor shall agree on any special precautions necessary with regard to conditions that may occur during operation, maintenance, transportation (see 6.5.14), erection, commissioning, and testing.

NOTE 1 Care is necessary in the selection of fabrication methods, welding procedures, and materials for vendor furnished steel pressure retaining parts that can be subject to temperatures below the ductile-brittle transition temperature. Some standards do not differentiate between rimmed, semi-killed, fully killed hot-rolled, and normalized material, nor do they take into account whether materials were produced under fine- or course-grain practices.

NOTE 2 In general ferritic steels (such as carbon steel and low-alloy steel containing chromium and molybdenum) and martensitic steels (such as 12% chrome) can have ductile-to-brittle transition temperatures as high as 40 °C (100 °F). The ductile-to-brittle transition temperature is affected by such items as steel manufacturing process heat treatment and minor changes in alloy content.

6.25.2 All pressure-containing components including nozzles, flanges, and weldments shall be impact tested in accordance with the requirements of Section VIII, Division 1, Section USC-65 through 68, of the ASME *BPVC*.

6.25.3 High-alloy steels shall be tested in accordance with Section VIII, Division 1, Section UHA-51, of the ASME *BPVC*.

6.25.4 Impact testing is not required if the requirements of Section VIII, Division 1, Section UG-20F, of the ASME *BPVC* are met.

6.25.5 Nominal thickness for castings as defined in Section VIII, Division 1, Paragraph UCS-66(2), of the ASME *BPVC* shall exclude structural support sections such as feet or lifting lugs.

6.25.6 The results of the impact testing shall meet the minimum impact energy requirements of Section VIII, Division 1, Section UG-84, of the ASME *BPVC*.

• **6.25.7** The specified minimum design metal temperature shall be used to establish impact test requirements and other material requirements.

6.26 Nameplates and Rotational Arrows

6.26.1 A nameplate shall be securely attached at a readily visible location on the equipment and on any major piece of auxiliary equipment.

6.26.2 Rotation arrows shall be cast in or attached to each major item of rotating equipment at a readily visible location.

6.26.3 Nameplates and rotation arrows (if attached) shall be of austenitic stainless steel or nickel-copper (UNS N04400) alloy.

6.26.4 Nameplate attachment pins shall be of the same material as the nameplate.

6.26.5 Nameplates shall not be welded to the casing.

6.26.6 The following data, as a minimum, shall be clearly stamped on the nameplates of the gas turbine units. Units used on the nameplates shall conform to the datasheet selected (SI or USC):

a) vendor’s name;

b) serial number;

c) model;

d) ISO-rated power and speed;

e) speed range;

f) overspeed trip set points.

7 Accessories

7.1 Starting and Helper Driver

7.1.1 General

• **7.1.1.1** Vendor shall furnish the type of starting or helper driver specified. The types of drivers available include electric motors, steam turbines, gas expansion turbines, internal combustion engines, hydraulic motors, pneumatic motors, and small gas turbines.

NOTE 1 Starting drivers are used to accelerate gas turbines (and driven equipment for single-shaft gas turbine trains) to self-sustaining speed and are normally shut down during operation.

NOTE 2 Helper drivers are used to accelerate gas turbines (usually single-shaft gas turbine trains) and driven equipment to self-sustaining speed and usually remain coupled during operation to provide supplementary shaft power to the gas turbine trains.

7.1.1.2 Starting steam turbines shall be termed “general-purpose turbines” in accordance with API 611.

7.1.1.3 Unless otherwise specified, helper steam turbines shall be in accordance with API 612.

• **7.1.1.4** Other types of starting and helper driver shall be supplied to the specified specifications and standards.

• **7.1.1.5** The gas turbine vendor shall supply all clutches, speed-changing gears, torque converters, or other power transmission equipment, including controls, required or specified for the starting and helper drivers.

7.1.1.6 Gears in intermittent service (e.g. starting) shall be in accordance with API 677.

7.1.1.7 Starting system shall be inhibited until conditions are appropriate for starting.

7.1.1.8 The starter and clutch shall be designed to prevent sudden clutch engagement or lock up during normal operation.

7.1.1.9 Proposal shall include details of the starter design and failure modes. See 9.2.3.2 m).

7.1.1.10 For electro-hydraulic start systems, the proposal shall clearly identify all design limitations, including the maximum distance between the starter skid and the gas turbine package interface point, oil volume limitations in the high-pressure starter supply lines, maximum supply and return line pressure drops, maximum duration of continuous starter operation, and number of consecutive start attempts allowed. See 9.2.3.2 m).

7.1.1.11 Unless otherwise specified, interconnecting piping and cabling between a separate starter skid and gas turbine package will be supplied by the purchaser in accordance with the vendor's specifications.

7.1.1.12 Mounting plates furnished for starter or helper drivers shall meet the requirements of 7.3.

7.1.1.13 Starting drivers and their associated power transmission equipment shall be sized for acceleration of the gas turbine unit and for either extended operation at purge or compressor cleaning cycles. Any starting driver not suitable for operation at speeds corresponding to turbine trip speed shall disengage automatically or trip at its trip speed. Failure of the starting driver to disengage or re-engagement during operation shall trip the gas turbine.

7.1.1.14 A gas-expansion starter or helper turbine using flammable gas for motive power shall be designed for zero leakage shaft seals.

NOTE Gas-expansion drivers are generally not preferred for environmental reasons.

7.1.2 Start and Helper Motors

• **7.1.2.1** Starter and helper motor drives shall conform to API 541, API 546, or IEC 60034-1, as specified.

7.1.2.2 For IEC 60034-1, motor mechanical design shall be in accordance with API 541 or API 546 (as applicable).

NOTE Since IEC 60034-1 is silent on mechanical design criteria of motors, the above API standards will be used.

7.1.2.3 Motors rated at 375 kW (500 hp) and above shall be in accordance with API 541.

7.1.2.4 Motors rated between 190 kW (250 hp) and 375 kW (500 hp) shall be in accordance with API 547.

7.1.2.5 Motors that are below the power scope of API 547 shall be in accordance with IEEE 841.

• **7.1.2.6** The motor's starting torque shall meet the requirements of the driven equipment, at a reduced voltage of 80 % of the normal voltage, or such other value as may be specified, and the motor shall accelerate to full speed within 15 seconds or such other period of time agreed upon by the purchaser and the vendor.

7.1.3 Ratings

7.1.3.1 As a minimum, starter drivers shall be rated to supply 110 % of the starting and acceleration torque required by the gas turbine package throughout the ambient temperature range (see 6.6).

NOTE 1 Starting drivers can be oversized (above the starting torque requirements) to provide additional power as a helper driver during normal operations.

NOTE 2 Single-shaft gas turbines (see Figure 1) need starters with enough torque to accelerate the driven equipment including any load on the driven equipment.

7.1.3.2 Proposal shall include speed-torque curve (prepared by the gas turbine manufacturer) for the gas turbine and driven equipment, with the starting driver torque superimposed to confirm delivery of the starting torque. See 9.2.3.2 m).

7.1.3.3 Helper driver ratings and arrangements shall be mutually agreed to by the purchaser and the vendor.

7.1.4 Turning Equipment

• **7.1.4.1** If specified or if required to avoid rotor deformation after a shutdown, a turning gear and/or ratchet device shall be furnished.

NOTE Some gas turbines do not need turning equipment. Turning gear can sometimes shorten the duration before a restart is allowed.

7.1.4.2 For gas turbines without free power turbines, the turning gear shall be sized to turn the entire train.

7.1.4.3 Details of turning gear operation, such as manual or automatic engagement/disengagement, and time required shall be mutually agreed upon by the purchaser and the vendor.

7.1.4.4 Uninterruptible power backup or other means shall be provided if ratcheting/turning is required to prevent bowing or distortion that will delay a restart.

7.1.4.5 The turning gear and/or ratchet device shall be designed to prevent rotor sudden engagement or lock up during normal operation. Proposal shall include details of the gear/ratchet design and failure modes [see 9.2.3.2 m)].

7.1.4.6 Turning gears shall not engage without adequate system lube oil pressure at all bearings for all coupled equipment.

7.1.4.7 If ratcheting/turning is required, provisions shall be made to allow for the manual barring of the gas turbine during failure or upon loss of power to the turning gear or ratchet device.

7.1.4.8 Driven equipment manufacturers shall review and endorse turning gear operation (e.g. bearing lubrication, seal lift off).

7.2 Gears, Couplings, and Guards

7.2.1 Gears

7.2.1.1 The gas turbine vendor shall furnish any gear required for starting and helper drivers, shaft-driver auxiliary equipment.

• **7.2.1.2** If specified, the load gear shall be furnished by the gas turbine vendor.

7.2.1.3 Load gears and helper driver gears shall be separate coupled units and shall comply with API 613.

7.2.1.4 Epicyclical gears shall be designed in accordance with AGMA 6123-C16 and rated per AGMA 2101-D04.

7.2.1.5 Load gears shall have minimum ratings equal to the potential maximum power of the gas turbine, plus the rated power of any helper drivers transmitting power through the gears.

7.2.1.6 Starting and helper driver gear rotors shall be rated for at least 110 % of the power developed by any starting and helper driver connected to them.

7.2.1.7 Auxiliary equipment gear rotors shall be rated for at least 110 % of the maximum power applied to them.

7.2.2 Couplings and Guards

7.2.2.1 The gas turbine vendor shall furnish couplings and guards (including adapter plates) between the gas turbine and starting/helper driver, auxiliary gears, load gear, or the first piece of load equipment.

7.2.2.2 All couplings shall be dry, flexible diaphragm or disk pack type. Rigid couplings with integrally forged shaft flanges may be used for generator drives.

• **7.2.2.3** If specified, a torque measuring system shall be provided for mechanical drive applications per API 671.

7.2.2.4 Main load couplings shall be designed and manufactured with the capability to transmit the maximum torque that can be developed at potential maximum power (see 3.1.47) and transient conditions, plus the maximum applicable helper turbine power output.

7.2.2.5 Coupling, coupling-to-shaft junctures, and guards between the gas turbine and starting/helper driver, load gear, or the load shall conform to API 671.

7.2.2.6 The make, type, and mounting arrangement of couplings and coupling guards, including vents and drains, shall be agreed upon by the purchaser and the vendors of the driver and driven equipment.

• **7.2.2.7** If specified, all couplings for speeds below 4k rpm shall be designed to ISO 14691.

7.2.2.8 Information on shafts, keyway dimensions (if any), and shaft end movements due to end play and thermal effects shall be furnished to the vendor supplying the coupling.

7.2.2.9 Coupling alignment diagram shall be provided with all shaft-end position changes and support growth from a reference temperature (see 7.2.2.10). Recommended alignment method and cold setting targets shall be described.

7.2.2.10 Unless otherwise specified the reference temperature (see 7.2.2.9) shall be 59 °F (15 °C).

7.3 Mounting Plates

7.3.1 General

• **7.3.1.1** Vendor shall blast-clean, in accordance with SSPC SP6 or ISO 8501 Grade Sa2, all grout contact surfaces of the mounting plates and coat those surfaces with a primer compatible with specified grout.

7.3.1.2 The manufacturer shall describe the actual primer used.

NOTE Epoxy primers have a limited life after application.

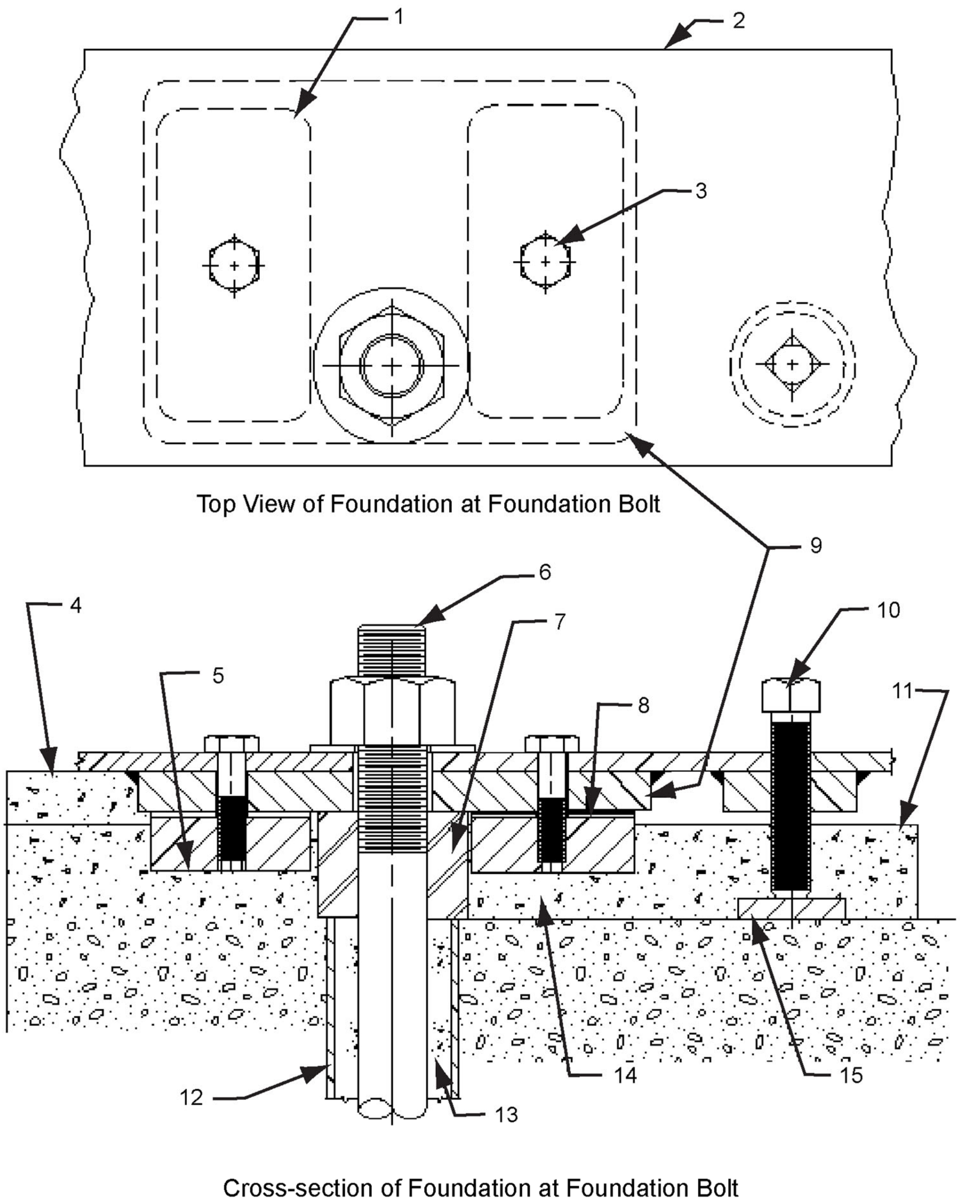
7.3.1.3 Anchor bolts shall not be used to fasten machinery to the mounting plates.

7.3.1.4 Mounting plates shall conform to the following.

a) Mounting plates shall not be drilled for equipment to be mounted by others.

b) Mounting plates shall be supplied with leveling screws. A leveling screw shall be provided near each anchor bolt.

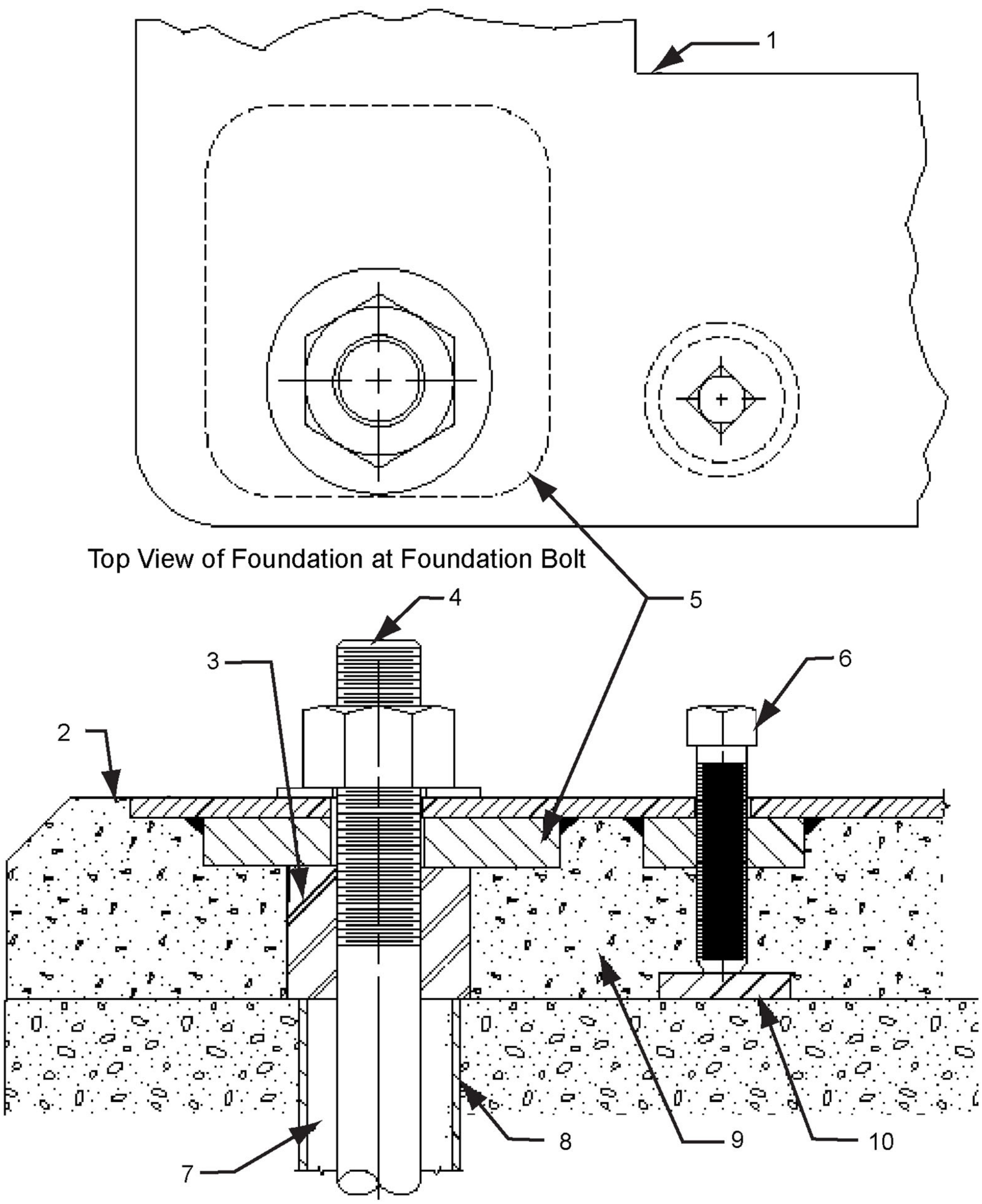
c) Outside corners of mounting plates that are embedded in the grout shall have 50 mm (2 in.) minimum radiused outside corners (in the plan view). See Figure 8 and Figure 9. Embedded edges shall be rounded to prevent the potential of cracking the grout.



Key

1 subplate	8 shims
2 baseplate beam	9 baseplate mounting pad
3 capscrew	10 levelling jackscrew
4 optional full bed grout level	11 grout level for shim access
5 subplate	12 anchor bolt sleeve
6 anchor bolt	13 nonbonding fill
7 anchor bolt sleeve grout seal	14 epoxy grout
	15 levelling plate

Figure 8—Typical Mounting Plate Arrangement A



Cross-section of Foundation at Foundation Bolt

Key

1 baseplate beam
2 grout level
3 anchor bolt sleeve grout seal
4 anchor bolt
5 baseplate mounting pad
6 levelling jackscrew
7 nonbonding fill
8 anchor bolt sleeve
9 epoxy grout
10 levelling plate

Figure 9—Typical Mounting Plate Arrangement B

7.3.1.5 The alignment shims shall be provided by the vendor in accordance with API 686 and straddle the hold-down bolts and vertical jackscrews and be at least 6 mm ($^1/_4$ in.) larger on all sides than the equipment feet. If the equipment is factory aligned and mounted to its baseplate as a single skid, shim packs may not be required between the machinery and the baseplate.

7.3.1.6 Unless otherwise specified, anchor bolts will be furnished by the purchaser.

7.3.1.7 Hold-down bolts used to attach the equipment to the mounting plates and all jackscrews, shall be supplied by the vendor.

7.3.1.8 Equipment shall be designed for installation in accordance with API 686.

7.3.2 Mounting Surfaces

7.3.2.1 All mounting surfaces shall be machined after the baseplate is fabricated.

7.3.2.2 All mounting surfaces shall be machined to a finish of 6.3 m (250 in.) R_a or better.

7.3.2.3 Each mounting surface shall be machined within a flatness of 40 m per linear meter (0.0005 in. per linear foot) of mounting surface.

7.3.2.4 All mounting surfaces on the same mounting plate shall be in the same horizontal plane shall be within 25 µm (0.001 in.) to prevent soft foot (see Figure 10). Baseplates fabricated in multiple sections shall be within mounting surface tolerances during trial fit-up at the vendor's facility.

7.3.2.5 Mounting planes for different equipment shall be machined parallel to each other within 50 µm (0.002 in.) (see Figure 11). Baseplates fabricated in multiple sections shall be within mounting surface tolerances during trial fit-up at the vendor's facility.

7.3.2.6 Equipment feet that require adjustment for field alignment shall be provided with vertical jackscrews and drilled with pilot holes that are accessible for use in final doweling (see 7.3.3).

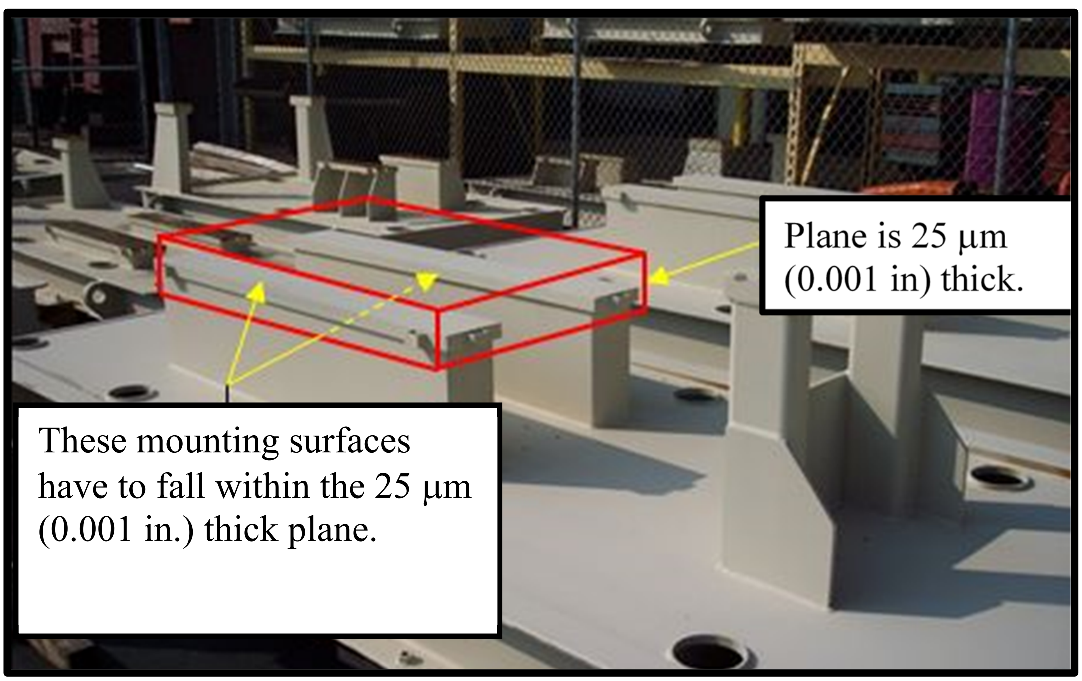


Figure 10—Mounting Surface Horizontal Requirements

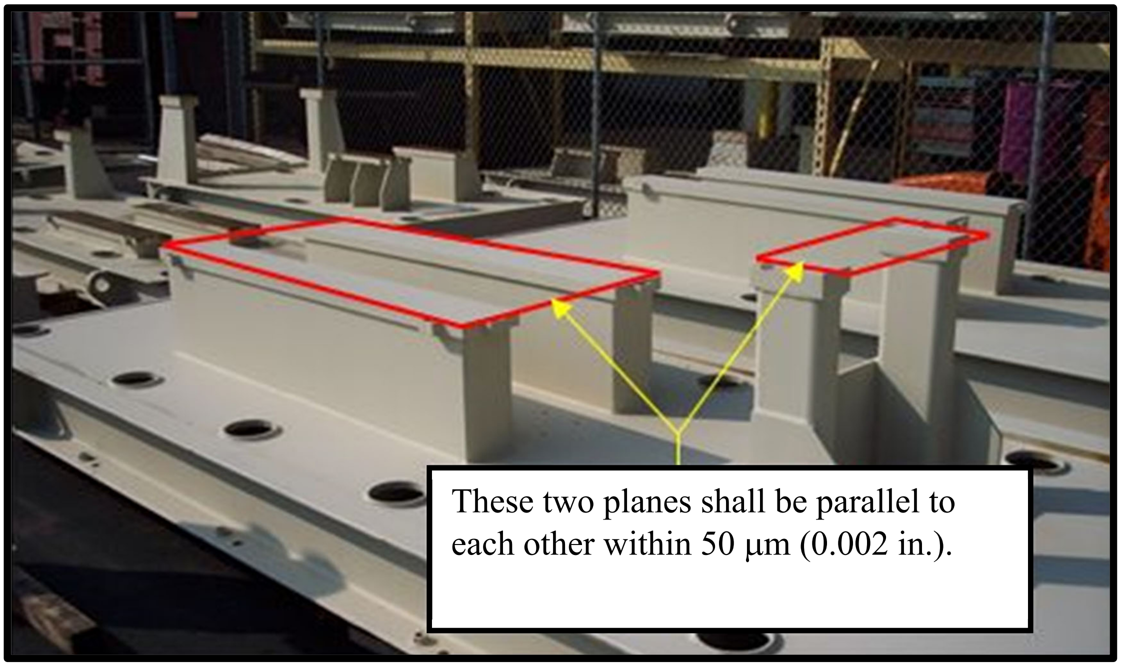


Figure 11—Mounting Plane Parallelism Requirements

7.3.3 Jackscrews and Dowelling

7.3.3.1 All major equipment (e.g. gas turbine, load gear, driven equipment) feet that require adjustment for field alignment shall be provided with vertical and horizontal jackscrews.

7.3.3.2 The mounting plate or plates that require adjustment for field installation shall be furnished with horizontal (axial and lateral) jackscrews, the same size or larger than the vertical jackscrews.

7.3.3.3 The lugs holding all jackscrews shall be attached to the mounting plates in such a manner that they do not interfere with the installation of the equipment, jackscrews, or shims.

7.3.3.4 Precautions shall be taken to prevent vertical jackscrews in the equipment feet from marring the shimming surfaces.

7.3.3.5 Alternative methods of lifting equipment for the removal or insertion of shims or for moving equipment horizontally, such as provision for the use of hydraulic jacks, may be proposed. Such arrangements should be proposed for equipment that is too heavy to be lifted or moved horizontally using jackscrews.

7.3.3.6 Jack screws shall have appropriate corrosion-resistant coating.

7.3.3.7 Equipment feet that require adjustment for field alignment shall be provided with vertical jackscrews and drilled with pilot holes that are accessible for use in final doweling.

7.3.4 Supports

7.3.4.1 Machinery supports shall be designed to limit the relative displacement of the shaft end caused by the worst combination of pressure, torque, and allowable piping stress to 50 μm (0.002 in.) at the coupling flange.

7.3.4.2 When pedestals or similar structures are provided for centerline supported equipment, the pedestals shall be designed and manufactured to permit the machine to be moved by using the horizontal jackscrews.

7.4 Baseplate

7.4.1 General

• **7.4.1.1** The gas turbine package, as well as its starting equipment, lubrication system, and all auxiliaries shall be furnished on the specified baseplate type.

NOTE Typical baseplate types are three-point mount, perimeter mount, or column mount.

7.4.1.2 All major equipment shall be mounted on the baseplate.

7.4.1.3 Proposal shall indicate the arrangement and location of auxiliary equipment furnished with the package. See 9.2.3.2 m).

7.4.1.4 A baseplate shall be a single fabricated steel unit, unless the purchaser and the vendor agree that it may be fabricated in multiple sections.

NOTE Baseplates with a nominal length of more than 12 m (40 ft) or a nominal width of more than 4 m (12 ft) might be fabricated in multiple sections to avoid shipping restrictions.

7.4.1.5 A baseplate fabricated in multiple sections shall have machined and doweled mating surfaces to ensure accurate field reassembly.

7.4.1.6 A baseplate fabricated in multiple sections shall be trial fit-up at the vendor's facility prior to shipment of the package.

7.4.1.7 Vendor shall advise the alignment procedure and acceptable tolerances.

7.4.1.8 Unless other suitable means of fixing targets is provided and if laser alignment is used, targets shall be permanently fixed to the baseplate.

7.4.1.9 The baseplate(s) shall extend under the drive-train components to contain and drain any leakage. All baseplates shall be capable of complete draining by gravity.

7.4.1.10 All joints, including deck plate to structural members, shall be continuously seal-welded on both sides to prevent crevice corrosion. Stitch welding, top or bottom, is unacceptable.

• **7.4.1.11** If specified, the baseplate shall be designed to facilitate the use of optical, laser based, or other instruments for accurate leveling in the field.

a) The details of such facilities shall be agreed by the purchaser and vendor.

b) Where the requirement is satisfied by the provisions of leveling pads and/or targets, they shall be accessible with the baseplate on the foundation and the equipment mounted.

c) Removable protective covers shall be provided for the targets.

d) Leveling pads or targets shall be located close to the machinery support points.

e) For baseplates longer than 6 m (20 ft), additional pads shall be located at intermediate points.

• **7.4.1.12** If specified, the baseplate shall be designed for column mounting (that is, of sufficient rigidity to be supported at specified points) without continuous grouting under structural members.

a) The baseplate design shall be mutually agreed upon by the purchaser and the vendor.

b) Design stiffness shall be verified by finite element analysis (FEA) or other similar suitable design tool taking into account all applicable loads, such as earthquake, lifting, operational, or transportation loads (see 6.5.14), etc.

7.4.1.13 The baseplate shall be provided with lifting attachments per 7.4.3.

7.4.1.14 Unless otherwise agreed, baseplates shall be designed for lifting with all equipment mounted.

7.4.1.15 Lifting the baseplate in accordance with manufacturer's lifting plan, complete with equipment mounted upon it shall not permanently distort or otherwise damage the baseplate or the equipment mounted on it.

NOTE Sometimes the gas generator is not installed when the baseplate is lifted.

7.4.1.16 Unless otherwise specified, the baseplate shall be designed for a four-point lift.

• **7.4.1.17** If specified, the lifting frame, all required slings and shackles and design calculations shall be provided (see 7.4.3).

7.4.1.18 Transportation lashing points shall be marked as such and have clear instructions that they are not for lifting.

7.4.1.19 When baseplates are designed for perimeter/point grouting under structural members, the bottom of the baseplate between structural members shall be open.

• **7.4.1.20** If specified, the baseplate is shall be designed for full grouting.

7.4.1.20.1 Fully grouted baseplates shall be provided with at least one grout hole having a clear area of at least 0.01 m^2 (20 $in.^2$) and no dimension less than 75 mm (3 in.) in each bulkhead section.

7.4.1.20.2 Grout holes shall be located to permit grouting under all load-carrying structural members.

7.4.1.20.3 Where practical, grout holes shall be accessible for grouting with the equipment installed.

7.4.1.20.4 Grout holes shall have 13 mm ($^1/_2$ in.) raised-lip edges, and if located in an area where liquids could impinge on the exposed grout, metallic covers with a minimum thickness of 3 mm ($^1/_8$ in.) shall be provided.

7.4.1.20.5 Vent holes at least 13 mm ($^1/_2$ in.) in size shall be provided at the highest point in each bulkhead section of the baseplate.

7.4.1.21 The underside mounting surfaces of the baseplate shall be in one plane to permit use of a single-level foundation. When multi-section baseplates are provided, the mounting pads shall be in one plane after the baseplate sections are doweled and bolted together.

NOTE Some driven equipment (e.g. onshore centrifugal compressors) have a baseplate in a different plane to that of the gas turbine baseplate.

7.4.1.22 Unless otherwise specified removable, galvanized steel in accordance with ASTM A123/A123M, serrated grating covering all walk and work areas shall be provided on the top of the baseplate.

• **7.4.1.23** If specified, stainless steel or glass-reinforced plastic serrated grating shall be provided.

7.4.1.24 The measurements in 7.3.2.1 to 7.3.2.5 shall be recorded and verified by placing the baseplate in unrestrained condition on a flat machined surface at the place of its manufacture.

7.4.2 Subsoleplates

• **7.4.2.1** If subsoleplates are specified, the soleplates shall be provided and shall maintain baseplate compliance with 7.4.

7.4.2.2 Subsoleplates shall have adequate working clearance at the bolting locations to allow the use of socket or box wrenches to achieve the required torque.

7.4.2.3 Subsoleplates shall have adequate clearance at the bolting locations to allow the equipment to be moved using the horizontal and vertical jackscrews.

7.4.2.4 Subsoleplates shall be steel plates at least 25 mm (1 in.) thick.

7.4.2.5 Subsoleplate mating surface finish shall match that of the baseplate [see 7.4.1.24 b)].

7.4.3 Lifting Lugs, Pad Eyes, and Trunnions

7.4.3.1 Design of lifting attachments shall be in accordance with ASME BTH-1, design category B.

7.4.3.2 Lifting attachments on the baseplate or equipment shall be designed using a maximum allowable dynamic stress of one-third of the specified minimum yield strength of the material.

7.4.3.3 Removable lugs or commercially available specialty products such as pivot type hoisting rings can be provided with purchaser approval.

7.4.3.4 All lifting lugs, pad eyes, and trunnions shall be furnished with material and load test certifications traceable to an internationally recognized standard and attested by an independently accredited third-party agency or organization approved by the purchaser.

7.4.3.5 Lifting lugs, pad eyes, and trunnions shall pass 100 % radiographic or ultrasonic inspection in accordance with AWS D1.1/D1.1M.

7.4.3.6 Materials that directly attach to lifting lugs, pad eyes and trunnions shall pass 100 % radiographic or ultrasonic inspection in accordance with AWS D1.1/D1.1M.

7.4.3.7 Test acceptance criteria shall be per the manufacturing code to which the equipment was fabricated.

7.5 Controls and Instrumentation

7.5.1 General

7.5.1.1 Instrumentation shall conform to the requirements of API 670, API 614, and 6.5.4.

• **7.5.1.2** Controls and instrumentation shall be designed for outdoor or indoor installation as specified.

• **7.5.1.2.1** All controls and instrumentation (including inside the enclosure) for outdoor installations shall be in accordance with IEC 60529 IP 66 or NEMA 250 4X, as specified.

7.5.1.2.2 Indoor installations shall have a rating suitable for the environment.

7.5.1.3 Where applicable, controls and instrumentation shall conform to API 551.

7.5.1.4 Mechanical equipment shall be assessed for its inherent capability to produce ignition sources, e.g. hot surface temperatures or sparking of rotating components.

7.5.1.5 Proposal shall describe the hazardous electrical area inside the gas turbine enclosure and any external hazardous areas generated by the gas turbine or its auxiliaries. See 9.2.3.2 m).

• **7.5.1.6** If specified, equipment installed in unclassified areas shall also be supplied certified for a hazardous location (see 6.5.4).

NOTE 1 This is typically done to ensure commonality of equipment furnished.

NOTE 2 Locations for installed equipment can be classified as hazardous electrical areas or they can be unclassified. An unclassified area is considered nonhazardous; therefore, motors, electrical instrumentation, equipment, components, and electrical installations for unclassified areas are not governed by hazardous area electrical codes.

7.5.2 Control Systems

7.5.2.1 Proposal shall clearly define the scope of controls being supplied. See 9.2.3.2 m).

7.5.2.2 Proposal shall document [see 9.2.3.2 m)] all required interfaces to third-party or purchaser-supplied control and utility systems such as:

a) anti-surge controls;

b) capacity and speed controls;

c) API 670 monitoring system and shutdown equipment;

d) fire detection and suppression controls;

e) gas detection controls;

f) human machinery interface (HMI);

g) condition monitoring;

h) distributed control system (DCS).

7.5.2.3 The gas turbine control system shall provide for startup of the gas turbine package, provide for stable operation, warn of abnormal conditions, monitor the operation, and shut down the unit.

7.5.2.4 Unless otherwise specified, the starting cycle of the gas turbine package shall be automatic (i.e. require only a single action by the operator to activate all auxiliary equipment and complete gas turbine starting sequence).

• **7.5.2.5** If specified, the starting cycle of the gas turbine package shall be semi-automatic (i.e. require manual activation of accessories and auxiliaries, but permit the operator to commit the gas turbine to the complete starting sequence by a single action).

7.5.2.6 The control system shall provide sufficient time for the gas turbine internals to warm up to reduce thermal strain effects and, if necessary, to heat rotating parts (turbine shaft and disks) to a temperature above any transition temperature.

7.5.2.7 The control system shall provide controlled acceleration to the minimum governor speed setting in order to reduce thermal strain effects, excessive mechanical stresses, or operation at critical speeds of any train component.

7.5.2.8 Under normal shutdowns, the control system shall provide a means to systematically cool down the gas turbine to prevent rotor bow or blade tip rubs on a subsequent startup. If a turning gear or ratcheting device is provided, it shall be automatically engaged by the control system at the end of the normal shutdown.

7.5.2.9 Vendor control system shall accommodate variation in starting, operating (see 6.6) and fuel compositions (see 7.9.2 and 7.9.4).

7.5.2.10 The control system logic solver shall be microprocessor based.

7.5.2.10.1 The gas turbine programmable logic controller (PLC) design shall ensure that processor and memory loading, including data storage, shall not exceed 75 % of system capacity during actual operation.

7.5.2.10.2 Controller loading shall be demonstrated prior to concluding the factory acceptance test (FAT).

7.5.2.11 Other parts of the control system may be mechanical, pneumatic, hydraulic, electric, electronic, microprocessor based, or any combination thereof.

7.5.2.12 The structure of the gas turbine control application program shall be segregated, as much as practical, so that upgrades and general revisions to the core gas turbine control logic can be completed without affecting the logic for auxiliary systems.

7.5.2.13 When the outputs of multiple controllers (e.g. speed control, firing temperature control, anti-surge control) are selected for controlling a final element (e.g. fuel valve), the outputs of all unselected controllers need to be tracked to the output of the active (selected) controller to prevent wind-up of the unselected controller. The control system shall recognize and take steps to mitigate adverse effects of wind-up.

NOTE Wind-up is a condition that can occur in a control function (controller) where the command signal varies in response to a feedback signal. If the feedback is not satisfied, the command signal increases until it cannot go higher. In that state, the control function can be slow to react to a change in the feedback signal, leaving the system "out of control." Wind-up can occur in gas turbine controllers where different control functions govern at different times during the gas turbine operation, i.e. startup control, speed control, acceleration, load control, and temperature control.

7.5.2.14 Proposal shall state the degree of redundancy, if any, of the proposed control system and shall fully describe how segregation of control and protection systems is achieved. See 9.2.3.2 m).

• **7.5.2.15** If specified, the redundant equipment required by the purchaser for any part of the control system proposed, e.g. entire logic solvers, central processing units (CPUs), sensors, power supply, etc. shall be supplied.

• **7.5.2.16** If specified, the redundant sensors and other inputs to the control system required by the purchaser shall be furnished in accordance with the arrangements in API 614.

7.5.2.17 The control system shall be designed to safely shutdown the gas turbine in the event of a loss of normal power.

NOTE This typically requires a battery-powered direct current (DC) power supply or alternative power source.

• **7.5.2.18** If specified, the control system shall be designed to maintain turbine operation and protection for a specified time period of interrupted electric power.

NOTE This time period would typically be a few minutes and an uninterruptible power system (UPS) would be required.

• **7.5.2.19** If specified, a communications link to the plant DCS shall be provided to allow for selected monitoring and remote operator control interface.

• **7.5.2.20** DCS data communicated, selected monitoring and remote control interface, and frequency of update for these links shall be as specified.

7.5.2.21 Automatic self-testing and system diagnostics shall be incorporated into the controller configuration and require no additional application logic.

7.5.2.22 All testing and system diagnostics shall be a proven integral part of the system and shall be completely transparent to the user when the application is implemented.

7.5.2.23 The diagnostics and tests may be continuous, periodic, or in the background at intervals commensurate with the devices or systems being controlled.

• **7.5.2.24** The control system safety integrity level (SIL) shall not be less than the specified SIL.

NOTE The specified SIL is determined by safety calculations performed by the purchaser.

7.5.3 Load Control

7.5.3.1 The gas turbine shall be provided with a control system that will receive the purchaser's control signal.

a) During normal operation, this external control signal shall control turbine speed or power as required.

b) The governor shall be capable of accessing the full range of the purchaser's control signal.

c) Unless otherwise specified, an increase in signal shall increase the turbine speed or power.

d) The governor shall include a means to manually override the external control signal and permit operation between the N_{ma} and N_{mc}.

e) The governor shall provide smooth (bumpless) transfer between semi-automatic and automatic external control modes.

7.5.3.2 If the speed or power becomes restricted by cycle temperature or other limit, indication of this status shall be provided to the purchaser control system.

7.5.3.3 Unless otherwise specified, the control range shall be as specified in 6.1.15 and 6.1.16. The control signal shall adjust the set point of the driver's speed-control system.

7.5.3.4 Unless otherwise specified, the maximum control signal shall correspond to the lesser of the gas turbine or driven equipment N_{mc}. The minimum control signal shall correspond to the maximum of the N_{ma} or the lowest speed the driven equipment can continuously operate.

7.5.3.5 The governor for mechanical drive applications shall limit speed to N_{mc}.

7.5.3.6 Multiple-shaft gas turbines shall also be provided with a speed limiter on each shaft, set for N_{mc}.

7.5.3.7 Governor systems shall prevent the gas turbine from tripping on overspeed when an instantaneous loss of driven load occurs. A controlled shutdown may occur in the event of these instantaneous load losses.

7.5.3.8 Speed regulation shall be in accordance with ISO 3977-3.

7.5.3.9 For power generation, gas turbine underspeed protection shall be coordinated with generator frequency protection, to allow operation during electrical system transient disturbances.

NOTE Many details of the site electrical system are required to fully define the level of coordination and set the transient response alarm and shutdown levels.

7.5.4 Purge Control

7.5.4.1 Control systems shall allow a purge period of sufficient duration to permit the displacement of the volume of the entire exhaust system (including the stack).

NOTE 1 Additional guidance can be sought in ISO 21789.

NOTE 2 Local regulations can dictate the purge requirements, such as the number of volume changes or flow rate.

NOTE 3 NFPA 85 allows for purge credits if certain parameters are met.

7.5.4.2 The gas turbine and all downstream components of the exhaust system shall be purged before gas turbine startup.

a) The purge flow rate should be sufficient to minimize unpurged voids.

b) The purge shall provide at least three complete volume changes of the gas turbine and downstream components of the exhaust system. The volume includes the gas turbine air inlet flange to the outlet of the exhaust stack or a point where, under all load conditions, the exhaust gas temperature is below 80 % of the auto ignition temperature measured in degrees Celsius of any flammable gases or vapors that may be present.

c) Purge shall not allow re-entrainment, reentry, or collection of heavier than air gases within the exhaust system.

7.5.4.3 Prior to ignition, the required purge volume shall be confirmed by the use of appropriate instrumentation interlocked to the startup sequence. Where the gas turbine air compressor provides the purge flow, confirmation of adequate gas turbine compressor rotation speed shall be used to verify the flow rate.

7.5.4.4 Where more than one gas turbine feeds a heat recovery system, precautions should be taken to ensure that reverse exhaust gas flows cannot pass back into another gas turbine under any purge, startup, maintenance, or other flow condition.

NOTE Safe isolation (blocking of duct or similar using spectacle or blank) of the exhaust system when another gas turbine is undergoing maintenance is needed to avoid exhaust gases leaking near personnel. An exhaust diverter valve is not necessarily adequate.

7.5.4.5 The integrity test for fuel shut-off and control valves shall be conducted during the purge period.

7.5.5 Alarms, Shutdowns, Trips, and Protection Systems

7.5.5.1 A machinery protection system shall be provided per API 670—Typical System Arrangement Using Distributed Architecture or API 670—Typical System Arrangement Using Integrated Architecture, which includes a comprehensive shutdown system to protect personnel, environment, and equipment from harm or damage due to equipment malfunction.

7.5.5.2 Each protection system shall protect a single machinery train.

7.5.5.3 Any single fault in 1-o-o-2 redundant logic or 2-o-o-3 logic shall be alarmed.

7.5.5.4 When redundant measurements are voted, vendor shall document the behavior of the voting logic when one, or more, measurements fail. The voting logic shall be approved by the purchaser.

7.5.5.5 Each sensor in a voting configuration shall be assigned to separate input modules of the controller to ensure segregation and reduce common modes of failure.

7.5.5.6 Maintaining the operator reset command (e.g. keeping reset pushbutton depressed) shall not prevent operation of a protective function or trip command.

7.5.5.7 Shutdowns and Trips

7.5.5.7.1 Normal shutdown shall follow an orderly, safe, step-by-step procedure based on the requirements of the specific machinery and applications.

7.5.5.7.2 Trips shall immediately cut off the fuel, steam, and water.

7.5.5.7.3 Restart shall be prevented until corrective action has taken place (e.g. giving a shutdown reset command).

7.5.5.7.4 Unless otherwise specified, a minimum of two package emergency shutdown push buttons, one on each of the longest sides of the enclosure, shall be provided locally adjacent to the access doors on the outside of the gas turbine enclosure.

7.5.5.7.5 The fuel governor shall also call for zero fuel on any shutdown condition.

7.5.5.8 Electronic overspeed trip protection shall be provided according to API 670.

7.5.5.9 For mechanical drive applications, overspeed trip protection shall operate at 105 % of N_{mc}.

7.5.5.10 For generator drive applications, overspeed trip protection shall operate no higher than 105 % of N_{mc}.

7.5.5.11 The gas turbine shall not be damaged by 100 % instantaneous load loss.

NOTE This can require special studies, including gas turbine and driven equipment inertia.

7.5.5.12 All gas turbines (including multi-shaft) shall have individual overspeed trip protection for each shaft, set such that momentary speed excursions cannot lead to component deformation or damage.

NOTE Some multi-shaft gas turbines have separate high-pressure compressor (HPC) shafts, within the gas generator, that could be impossible to overspeed, with proper protection on the lower pressure shafts. A free power turbine always needs overspeed protection.

• **7.5.5.13** Instrumentation, control devices, and annunciation display units shall be furnished and mounted by the vendor as specified.

• **7.5.5.13.1** Alarms and shutdowns shall be as specified. Recommended alarm, shutdown, and required trip conditions are listed in Table 2.

7.5.5.13.2 Each shutdown function shall have an alarm that precedes the shutdown so that corrective action may be taken.

7.5.5.13.3 All shutdown and trip functions shall have a simultaneous alarm. Some trips may not require a preceding alarm (see Table 2).

Table 2—Required Trips and Recommended Alarms and Shutdowns

Condition	Alarm High or Low	Shutdown High-High or Low-Low	Trip
High radial shaft vibration	X	X	
Axial thrust position	X	X	
Overspeed			X
High casing vibration	X	X	
High thrust or radial bearing temperature	X	X	
Low fuel supply pressure	X		
High turbine exhaust temperature	X		
Emergency shutdown push button			X
High differential pressure across air inlet filter	X	X	
High firing/exhaust temperature spread	X	X	
Combustor-stage flameout		X	
Total control system failure			X
Failure of redundant element within control system	X		
Failure of starting clutch to engage or disengage	X		
Low lube oil pressure	X	X	
High or low lube oil reservoir level	X		
High lube oil filter differential pressure	X		
Lube oil spare pump operation	X		
Low control-oil pressure	X	X	
Other protective devices on turbine auxiliaries	X		
Externally provided nonemergency process or driven equipment malfunctions		X	
Externally provided emergency process or driven equipment malfunctions			X
Enclosure ventilation system failure	X	X	
Enclosure inlet/exhaust gas detection	X		X
Combustion air gas detection	X		X
Enclosure fire detection	X		X

• **7.5.5.14** Alarm and shutdown arrangements shall be in accordance with API 614, as specified.

7.5.5.14.1 Transmitters shall be used for alarm, shutdown, and trip functions for measurement of level, position, vibration, and pressure. Eddy current probes may measure shaft position without a transmitter. Temperature may be measured without a transmitter.

• **7.5.5.14.2** If specified, switches may be used for alarms, shutdowns, or trips.

a) Switches shall be hermetically sealed, single-pole, double throw design with a minimum capacity of 5 A at 120 V alternating current (AC) and 0.5 A at 120 V DC.

b) Mercury switches shall not be used.

c) Switch settings shall not be adjustable from outside the housing.

7.7.5.15 All circuits shall be fail-safe. Devices shall open to annunciate alarm, shutdown, or trip as appropriate.

NOTE Switches connected to open (de-energize) are normally considered to be fail-safe.

7.5.5.16 Pressure elements shall be, as a minimum, 316 or 316L stainless steel, and shall be compatible to the system fluids at all foreseeable operating conditions.

7.5.5.17 Alarm and shutdown circuits shall be arranged to permit testing of the control circuit, including the actuating element, while running without interfering with normal operation of the equipment (e.g. test bypass switches).

NOTE Not all circuits and end devices are accessible for testing or allowed (e.g. overspeed) while gas turbine is running.

7.5.5.18 The panel shall include a clearly visible light to indicate if circuits are in the test bypass mode.

7.5.5.19 Low-pressure alarms shall be equipped with valved bleed or vent connections to allow controlled depressurizing so that the operator can note alarm set pressure on the associated pressure gauge.

7.5.5.20 High-pressure alarms shall be equipped with valved test connections so that a portable test pump can be used to raise the pressure.

7.5.5.21 Proposal shall include complete descriptions of the alarm and shutdown testing facilities to be provided, together with any safety critical circuits that are not supplied with test bypass switches. See 9.2.3.2 m).

7.5.5.22 An audible alarm such as a bell, horn or annunciator that is actuated by the alarm and shutdown signals shall be provided on the control panel.

• **7.5.5.23** Unless otherwise specified, a first-out annunciator, with at least 20 % spare points, shall be furnished.

NOTE If alarms and messages are displayed with time-stamp then first-out annunciator could be unnecessary.

7.5.5.24 For fire and gas protection functions, alarm indication shall be via an audible alarm and an associated flashing message at the control system interface and by a flashing light and the sounding of a horn or another audible device at the equipment enclosure.

7.5.5.25 The alarm condition shall be acknowledged by operating an alarm-silencing button common to all alarm functions.

7.5.5.26 If the alarm is acknowledged, the horn or other audible device shall be silenced, but the light shall remain steadily lit as long as the alarm condition exists. The annunciator shall be capable of indicating a new alarm (with a flashing light and sounding horn) if another function reaches an alarm condition, even if the previous alarm condition has been acknowledged but still exists.

• **7.5.5.27** If specified, the alarm, shutdown, and trip system shall incorporate an event recorder to record the order of occurrence of alarms and shutdowns. Time resolution shall be not greater than 100 ms.

NOTE The scanning rate of the special event recorder, normally associated with a DCS, can be too slow.

7.5.5.28 Where practical and accessible, the necessary valving, switches, bridging links ("jumpers"), or other approved protocol shall be provided to enable all instruments and other components, except shutdown and trip sensing devices, to be replaced with the equipment in operation.

NOTE Many instruments inside the gas turbine enclosure can be inaccessible during operation and preclude meeting this requirement.

• **7.5.5.29** If specified, shutdown sensing devices shall be provided with isolation valving, bridging links, or other approved protocol to allow replacement with the equipment in operation. Isolation valves for shutdown sensing devices shall be provided with means of locking the valves in the open position.

NOTE 1 Many instruments inside the gas turbine enclosure can be inaccessible during operation and preclude meeting this requirement.

NOTE 2 Safety regulations can prohibit the use of bypass devices on certain loops (e.g. overspeed).

7.5.5.30 Proposal shall list all devices that cannot be changed on line or that cannot be supplied with a lock-open capability. See 9.2.3.2 m).

7.5.6 Control Panels

7.5.6.1 The control panel shall control both the gas turbine and the driven equipment.

NOTE Unusual driven equipment or process requirements can require modifications to the control techniques.

7.5.6.2 Unless otherwise specified, an off-skid control panel(s) shall be provided.

a) off-skid consoles shall be suitable for installation in a nonhazardous, indoor area,

• b) Cables between the control panel and gas turbine shall be the specified length.

NOTE Vendor can advise the maximum practical cable length options, e.g. 1000 ft (300 m).

c) Proposal shall describe the control panel and maximum allowable cable length between the control panel and the gas turbine, etc. See 9.2.3.2 m).

d) VDDR [see Annex B, item 12 f)] shall describe the control panel, including lights, switches, button, visual screens, maximum allowable cable length between the control panel and the gas turbine, etc.

• **7.5.6.3** If specified, an on-skid control panel shall be provided.

a) Control panel shall conform to 6.5.4.

b) Proposal shall describe the control panel. See 9.2.3.2 m).

c) VDDR [see Annex B, item 12 f)] shall describe the control panel, including lights, switches, button, visual screens, etc.

7.5.6.4 The control system shall be of a design that has been proven by experience of having been installed in at least three similar gas turbine applications, have at least 10k operating hours in gas turbine service, and the system and configuration being provided represent the vendors’ standard equipment.

• **7.5.6.5** The control system shall be either AC or DC powered as specified.

7.5.6.6 Unless otherwise specified, DC-powered control systems shall have redundant battery chargers and battery packs to provide all control power for the minimum time required for a controlled shutdown or at least 30 minutes. See also 7.5.2.17.

NOTE The battery system could be supplied by purchaser as part of an overall battery system.

7.5.6.7 Proposal shall describe all utility requirements and durations for startup, normal operation, normal shutdown, and emergency trip safely and without any damage (e.g. control system, operation of post lube, oil ventilation system, enclosure ventilation after loss of primary power, purging exhaust). See 9.2.3.2 m).

7.5.6.8 Purchaser will provide all noncontrol system utilities requirements including the UPS necessary to shut down the gas turbine safely and without any damage.

7.5.6.9 Proposal shall describe all the power requirements necessary to maintain uninterrupted operation of the gas turbine during a main power interruption, for the time period of interrupted electric power (see 7.5.2.18). See 9.2.3.2 m).

7.5.6.10 All control cabinets designed to be outdoors, and that contain electrical contacts, relays, or instruments, shall have provisions to prevent contamination and corrosion. If dry air is used for purging, dry air will be furnished by the purchaser.

• **7.5.6.11** If specified, all control modules (e.g. governor control panel, fire panel, protective relays) within the control cabin that employ printed circuit boards shall be protected from hydrogen sulfide (H_2S) corrosion by chemical filtration of the supply air to the control cabin or all printed circuit boards shall have conformal coatings to API 670.

7.5.7 HMI

7.5.7.1 Control panels shall include an HMI visual display unit for monitoring operating variables and/or a keyboard for entering operator commands.

7.5.7.2 The HMI shall be driven from a microprocessor-based system independent of the gas turbine control system, with communication between the visual display monitor and the gas turbine controls to be accomplished through a data link.

7.5.7.3 The type (e.g. touchscreen, pushbuttons, annunciator panel, etc.) of HMI used for local and/or remote operation of a packaged unit and its location shall be approved by the purchaser.

• **7.5.7.4** In addition to the HMI in the control panel, the specified number and type (panel, desktop, or portable) of remote HMIs shall be supplied.

• **7.5.7.5** Control system shall be capable of communicating with remote HMIs utilizing the specified communication protocol.

7.5.7.6 HMI—Display

7.5.7.6.1 Vendor's standard HMI graphics shall be provided to minimize custom development and to provide a common interface for vendor's field service personnel. However, the purchaser shall approve all graphics.

7.5.7.6.2 All graphics shall incorporate project-specific equipment tag numbers.

• **7.5.7.6.3** If specified, the HMI shall include startup sequence graphics as follows.

a) All startup sequence steps with permissive status shall be shown on an HMI graphic to allow the operator to prepare for and take any required manual actions and quickly determine the reason for delays in completing the startup sequence or failure of the startup sequence.

b) In the event of a start sequence failure, the control system shall annunciate the failed start and indicate the device or condition preventing progression of the start sequence.

c) The progress of the startup of auxiliaries and the full starting sequence shall be time-stamped and indicated on the control system HMI, showing a clear description of each step of the startup sequence.

7.5.7.7 HMI—Alarm High-High and Trip Graphics

7.5.7.7.1 Each alarm, shutdown and trip message shall include the instrument or equipment tag number, the machine unit number, and a clear, concise message.

7.5.7.7.2 If the alarm condition has cleared, the alarm message shall remain on the graphic until acknowledged by the operator.

7.5.7.7.3 When the alarm condition is cleared and the operator has acknowledged the alarm, the alarm message shall be removed from the graphic.

7.5.7.7.4 If any alarm or protective function can be bypassed, then an alarm shall be activated to alert the operator of the bypass. When any protective function is bypassed, the bypass shall be indicated in all the HMIs.

7.5.7.7.5 Alarm status shall be made available to the DCS.

7.5.7.7.6 All machinery process variables, including flows, temperatures, pressures, speeds, differential pressures, and vibration, shall be displayed.

7.5.7.7.7 Colors used for all valve operation and pump/motor running status shall be consistent throughout the facility to avoid operator misinterpretation. Purchaser shall approve all colors.

7.5.7.8 HMI—Archiving

7.5.7.8.1 HMIs shall be capable of providing trip logs that archive defined analog values, discrete events, and alarms, for a predetermined time period before and after the trip.

7.5.7.8.2 HMIs shall be capable of storing and displaying alarm shutdown and trip messages for at least 30 days.

7.5.8 Electrical and Instrumentation Systems

• **7.5.8.1** All electrical systems (e.g. motors, heaters, and instrumentation) shall be compatible with the specified electrical characteristics.

7.5.8.2 Unless otherwise specified, the motor control centers, power distribution control panels, and/or any UPS will be supplied by the purchaser.

7.5.8.3 A pilot light shall be provided on the incoming side of each supply circuit to indicate that the circuit is energized.

7.5.8.3.1 Unless otherwise specified, the pilot lights shall be installed on the motor control centers, power distribution control panels, and/or any UPS.

7.5.8.3.2 As an alternative to pilot lights, an alarm may be initiated if any of the power supplies is cut off.

7.5.8.4 The utility consumption list for the UPS shall be jointly developed by the purchaser and vendor.

7.5.8.5 All electrical equipment located in a hazardous environment shall conform to 6.5.4.

7.5.8.6 Power and control wiring within the confines of the baseplate shall be resistant to oil, heat, moisture, and abrasion.

7.5.8.7 A high-temperature, oil-resistant thermoplastic sheath shall be provided for wire insulation protection.

7.5.8.8 Wiring shall be suitable for the environment temperatures.

7.5.8.9 To facilitate maintenance, adequate clearances shall be provided for all energized parts (such as terminal blocks and relays) on turbine and auxiliary equipment.

7.5.8.9.1 For 600 V or lower systems, the clearances required for 600 V service shall be used or clearances shall meet the requirements of IEC 60204-1.

7.5.8.9.2 Enclosures shall be provided for all energized parts to guard against accidental contact.

7.5.8.10 Electrical materials, including insulation, shall be corrosion resistant and nonhygroscopic insofar as is possible.

• **7.5.8.11** If specified for tropical location, electrical materials shall be in accordance with the following.

7.5.8.11.1 Parts (such as coils and windings) shall be protected from fungus attack.

7.5.8.11.2 Unpainted surfaces (lugs, terminals, etc.) shall be protected from corrosion.

7.5.8.11.3 Unpainted surfaces shall be protected from corrosion by plating or another suitable coating.

7.5.8.12 Control, instrumentation, and power wiring (including temperature element leads) within the limits of the baseplate shall be protected against damage, minimize vibration, and prevent interference between voltage levels by being installed with proper shielding, bracketing, and support inside suitable:

a) metallic conduit,

b) mechanically protected areas,

c) sheathing, or

d) braiding.

7.5.8.13 Conduits may terminate (and in the case of temperature element heads, shall terminate) with a flexible metallic conduit long enough to permit access for maintenance without removal of the conduit.

7.5.8.14 For Class 1, Division 2 locations, flexible metallic conduits shall have a liquid tight thermosetting or thermoplastic outer jacket and approved fittings. Nonjacketed flexible cable (BX cable) may be used.

7.5.8.15 For Class 1, Division 1 locations, an NFPA-approved connector shall be provided.

7.5.8.16 AC and DC circuits shall be clearly labeled, identifiable by color coding of the individual wires and connected to separate terminal blocks, and electrically isolated from each other.

NOTE Local regulations can mandate AC and DC circuits be wired to separate junction boxes and the wiring colors to be used.

7.5.8.17 Grounding systems in accordance with IEC 61000-5-1 and IEC 61000-5-2 shall be fitted on each individual skid, such as:

a) skid base on two diagonally opposite corners;

b) inlet and exhaust ducting;

c) control panels;

d) lube oil skids.

• **7.5.8.18** Terminal boxes shall be in compliance with either IEC 60529 IP 66 or NEMA 250 4X as specified.

7.5.8.19 Unless otherwise specified, terminal boxes shall be, as a minimum, made of 316 or 316L stainless steel.

7.5.8.20 All conduit, cable and supports shall be designed and installed so that it can be easily removed without damage and shall be located so that it does not hamper removal of bearings, seals, or equipment internals.

7.5.8.21 Purchaser connections to switches, transmitters, and instruments on the package shall be from a minimum number of terminal boxes mounted at each skid edge.

7.5.8.21.1 Access to terminal boxes for incoming and outgoing conduits shall not be obstructed by skid members or enclosure components.

7.5.8.21.2 Terminal boxes are to be mounted so they are not disturbed during routine maintenance.

7.5.8.21.3 All purchaser connections shall be defined. Wire type, route, and entry details to the terminals shall be mutually agreed.

7.5.8.21.4 Top wire entry into any component (e.g. junction box, panel) outside the enclosure shall not be used.

NOTE In some cases top entry is the best option, but top entry is more difficult to seal than bottom or side entry.

7.5.8.21.5 Wire splices shall not be used.

7.5.8.21.6 All leads and posts on terminal strips, devices, and instruments shall be permanently tagged for identification, using a mutually agreed system.

7.5.8.21.7 All terminal boards in junction boxes and control panels shall have at least 20 % spare terminal points.

• **7.5.8.21.8** Control and instrumentation wiring that is not within a fully enclosed panel or other enclosure shall be in the form of armored cable or shall be run in metal conduit as specified. If used, cable ties shall be suitable for the maximum expected temperature.

7.5.8.21.9 If armored cable is used, it shall be installed as follows:

a) armored cable shall be supported on cable tray;

b) the cable tray shall be manufactured from material suitable to last the service life (see 6.1.2) of the equipment under all foreseeable operation and environmental conditions (see 6.6);

c) cable tray shall have sufficient rigidity to withstand a 900 N (200 lbf) or 170 kPa (25 psi) static point load without damage;

d) cable glands shall be certified for the hazardous area they are installed within;

e) low-smoke, non-polyvinyl chloride (PVC) sheathed cables shall be provided;

f) power and instrument cables shall not be installed adjacent to each other but may share the same tray if separation distances are maintained;

g) integrity of cable shields shall be maintained at junction boxes;

h) all cable trays shall have at least 20 % spare capacity.

7.5.9 Instrumentation

7.5.9.1 Tachometers

7.5.9.1.1 The control systems shall measure and display all gas turbine shaft speeds in rpm units.

• **7.5.9.1.2** If specified, a separate tachometer display shall be provided.

• **7.5.9.1.3** The speed sensor shall be active or passive, as specified (see API 670).

7.5.9.1.4 Unless otherwise specified, the minimum range shall be from 0 % to 125 % of N_{mc}.

7.5.9.1.5 Unless otherwise specified, all tachometer displays shall be digital.

NOTE Some digital tachometers are not accurate below 300 rpm.

7.5.9.2 Temperature Instruments

7.5.9.2.1 All temperature instrumentation shall be provided for all temperatures displayed within the HMI.

7.5.9.2.2 VDDR [see Annex B, item 12)] shall include a complete listing of all temperatures, which shall be recorded.

7.5.9.2.3 Dial-type temperature gauges shall be heavy duty and corrosion resistant, as a minimum, with 316 stainless steel wetted components and housings.

7.5.9.2.4 Dial-type temperature gauges shall be at least 100 mm (4 in.) in diameter and bimetallic.

7.5.9.2.5 Dial-type temperature gauges shall have black printing on a white background.

7.5.9.2.6 The sensing elements of temperature gauges shall be immersed in the flowing fluid.

NOTE This is particularly important for lines that are only partially full.

7.5.9.2.7 Temperature gauges that are in contact with flammable or toxic fluids or that are located in pressurized or liquid flooded lines shall be furnished with national pipe thread (NPT) $^3/_4$, as minimum, 316 or 316L stainless steel separable solid-bar thermowells.

7.5.9.3 Thermocouples and Resistance Temperature Detectors

7.5.9.3.1 Where practical, the design and location of thermocouples and resistance temperature detectors (RTDs) shall permit replacement while the unit is operating.

7.5.9.3.2 The lead wires of thermocouples and RTDs shall be installed as continuous leads between the thermowell or detector and the terminal box.

7.5.9.3.3 Conduit runs from thermocouple and RTD heads to a pull box or boxes located on the baseplate shall be provided.

• **7.5.9.3.4** If specified, temperature monitors shall be supplied, installed, and calibrated in accordance with API 670 and 7.5.1.2.1.

7.5.9.3.5 Unless otherwise specified, all necessary switches and indicators, for thermocouples and RTDs, shall be provided.

7.5.9.4 Pressure Gauges

7.5.9.4.1 Pressure gauges (not including built-in instrument air gauges) shall be furnished with, as a minimum, 316 stainless steel bourdon tubes and stainless steel movements.

a) Materials shall be selected to suit the working fluids.

b) A minimum of 100 mm (4 in.) dials, and NPT $^1/_2$ male alloy steel connections.

c) Pressure gauges shall have black printing on a white background.

d) Gauge ranges shall preferably be selected so that the normal operating pressure is at the middle of the gauge’s range.

e) The maximum reading on the dial shall not be less than 110 % of the applicable relief valve set point.

f) Each pressure gauge shall be provided with a device such as a disk insert or blowout back designed to relieve excess case pressure.

• **7.5.9.4.2** If specified, glycerin-filled gauges shall be furnished.

7.5.9.4.3 Differential pressure gauges shall be designed to prevent damage by over-ranging on any individual leg or between the legs.

7.5.9.5 Solenoid Valves

7.5.9.5.1 The use of direct solenoid-operated valves is restricted to applications with clean (filtered) working fluids.

7.5.9.5.2 All solenoid valves shall have Class F insulation or better and shall have a continuous service rating.

7.5.9.5.3 If required for other services, the solenoid shall act as a pilot valve to pneumatic valves, hydraulic valves, and the like.

7.5.9.6 Vibration and Axial Position Detectors and Monitors

7.5.9.6.1 Shaft vibration and axial position transducers and monitors for use with hydrodynamic bearings shall be supplied, installed, and calibrated in accordance with API 670 and 7.5.1.2.1.

7.5.9.6.2 Casing and bearing housing vibration transducers and monitors shall be supplied, installed, and calibrated in accordance with API 670 and 7.5.1.2.1.

7.5.9.7 Chip Detectors

7.5.9.7.1 Drains from sumps containing rolling elements shall contain magnetic particle (chip) detectors.

NOTE Chip detector is also known as a “wear metal particulate” detector.

• **7.5.9.7.2** If specified, chip detector shall provide electronic real-time detection and quantification of debris.

7.5.9.7.3 Proposal shall indicate the type, number, and location of chip detectors. See 9.2.3.2 m).

7.5.9.8 Combustor Flameout Protection

7.5.9.8.1 System for detection of combustor flameout shall be provided.

• **7.5.9.8.2** If specified, this system shall include rate of change detectors for shaft speed (dn/dt) or flame detectors (optical, ultraviolet, infrared) or temperature sensors to detect falling temperatures in the combustor area.

7.6 Piping and Appurtenances

7.6.1 General

7.6.1.1 The following auxiliary systems shall be in accordance with API 614 as modified in the following paragraphs:

a) instrument and control air;

b) cooling water;

c) lubrication oil;

d) control oil;

e) hydraulic oil.

7.6.1.2 Piping and tubing mounted on aeroderivative gas generators may be per manufacturers' aircraft design practices.

7.6.1.3 Unless otherwise specified, the following auxiliary systems shall be in accordance with Table 3 (see 6.20 for corrosive fluids):

a) fuel gas system;

b) liquid fuel system;

c) vent systems;

d) drain systems;

e) wash water system;

f) water injection system;

g) steam injection system;

h) starting air system;

i) starting gas system;

j) compressor bleed air or cooling air systems;

k) high-pressure hydraulic oil system;

l) jacking oil system.

Table 3—Minimum Piping Materials

Pipe	ASME B36.19M or ASME B36.10M seamless, ASTM A312/A312M Type 316L or other equivalent internationally recognized standard as approved by the purchaser.
Pipe fitting	ASME B16.9 seamless, ASTM A403/A403M Type 316L or other equivalent internationally recognized standard as approved by the purchaser.
Flange	SAE J518 or ASME B16.5 weld neck or slip-on, ASTM A182/A182M Type 316L or other equivalent internationally recognized standard as approved.
Tubing	ASTM A269/A269M Type 316 or 316L or other equivalent internationally recognized standard as approved by the purchaser.
Tube fittings	Type 316 or 316L or other equivalent internationally recognized standard as approved by the purchaser.
Gaskets	Spiral wound gaskets with non-asbestos filler and 316 stainless steel windings, inner rings, and external centering ring.
Flange bolting	ASTM A193/A193M Grade B8M or other equivalent internationally recognized standard as approved by the purchaser.
Valves	Carbon steel body with 316 or 316L stainless steel wetted parts or purchaser-approved materials.
Plate	ASTM A240/A240M Type 316 or 316L or other equivalent internationally recognized standard as approved by the purchaser.

7.6.1.4 Piping systems furnished by the vendor shall be fabricated, installed in the shop, and properly supported.

7.6.1.5 Bolt holes for flanged connections shall straddle lines parallel to the main horizontal or vertical centerline of the equipment.

7.6.1.6 Pipe plugs shall be in accordance with 6.13.5.

7.6.1.7 Proposal shall detail the use of flexible hose. See 9.2.3.2 m).

7.6.1.8 When provided, flexible hoses shall meet the product, installation, and testing requirements in ISO 10380, ISO 15465, and ISO 17784, as applicable.

• **7.6.1.9** Tube fitting manufacturer shall be as specified.

7.6.2 Oil Piping

7.6.2.1 Provisions, adjacent to bearing housings, shall be made for bypassing the bearings during oil system flushing.

7.6.2.2 Provisions to bypass hydraulic actuators during oil flushing shall be provided.

7.7 Inlet and Exhaust Systems

7.7.1 General

7.7.1.1 An inlet and exhaust system consisting of an inlet air filter, inlet and exhaust silencers, inlet and exhaust expansion joints, and inlet and exhaust ducting shall be supplied.

• **7.7.1.2** The gas turbine air inlet and exhaust orientation shall be as specified.

7.7.1.3 All external structural support shall be hot-dipped galvanized carbon steel in accordance with ASTM A123/A123M.

7.7.1.4 General Inlet and Exhaust Ductwork

• **7.7.1.4.1** All structural support systems and steelwork for inlet and exhaust systems and ductwork shall be provided to match the specified interface points. If interface points are not specified, the interface shall be the plane defined by the bottom of the gas turbine skid.

NOTE Ductwork is the entire duct system, including duct and associated support structure, insulation, instrumentation, and internals.

7.7.1.4.2 Vendor shall identify weights, dimensions, and center of gravity for each duct section that will be moved during installation [see Annex B—item 41)].

7.7.1.5 Unless otherwise specified, 1600 starts shall be used for all inlet and exhaust ductwork and support system design.

NOTE 1600 starts is about 1 start per week for 30 years. The fatigue of the structure is more influenced by thermal cycles (starting and stopping) than continuous operation.

7.7.1.6 Purchaser will describe vessel motion for floating applications (period, pitch, roll, etc.).

7.7.1.7 The inlet and exhaust systems shall meet the sound pressure level requirements of 6.3.

7.7.1.8 Intermittent noise sources, e.g. blowoff systems, shall be considered in the analysis.

7.7.1.9 Connections for sensing pressure at the gas turbine inlet and exhaust shall be supplied in accordance with ASME PTC 22 or ISO 2314.

• **7.7.1.10** The inlet and exhaust systems shall withstand the specified environmental loading (see 6.6), including snow or ice buildup, seismic, special wind loads, or shipping loads.

7.7.1.11 Manways

7.7.1.11.1 Manway openings shall be at least 600 mm × 600 mm (24 in. × 24 in.) or 600 mm (24 in.) in diameter.

• **7.7.1.11.2** If specified, or if the manway door weighs more than 25 kg (55 lbm) then the manway door shall have a lifting lug with handling davit or hinges that are correctly located with regard to the center of gravity of the door.

7.7.1.11.3 Manway covers shall be designed to permit their removal without risk of fasteners or other objects entering the gas turbine.

• **7.7.1.12** If specified, the inlet plenum shall have a window for observation of the bell mouth during operation and compressor washing.

NOTE Windows are commonly used to observe water wash, ice buildup, etc.

7.7.1.13 Expansion joints shall be provided between the ducting and gas turbine inlet and exhaust flanges to accommodate the relative movement of the ducting, regenerator (if any) and gas turbine in vertical and horizontal directions.

7.7.1.14 Expansion joints shall have internal liners.

NOTE Internal liners mitigate flutter, joint deterioration, and pressure drop.

• **7.7.1.15** If specified, expansion joints shall have provisions to attach sound-absorbing material, even if sound-absorbing material is not required.

7.7.1.16 An acceptable inlet joint may be fabricated from a flexible material.

7.7.2 Inlet Systems

7.7.2.1 General Design

7.7.2.1.1 Combustion air inlet systems [air inlet through to and including the gas turbine inlet plenum, including stiffening ribs (brackets) and all materials welded to the inlet system and ductwork] and enclosure ventilation air systems shall be, as a minimum, 316 or 316L stainless steel.

NOTE Inlet plenums made of composite materials have been successfully used for some applications.

7.7.2.1.2 Zinc and galvanized materials shall not be used in the air flow path of air inlet systems.

7.7.2.1.3 Inlet System Pressure Drop

7.7.2.1.3.1 The inlet system (from free ambient air through to the upstream flange of the inlet plenum, excluding any inlet cooling) shall have a maximum total pressure drop of 4 in. of water (1 kPa) with new and clean air filters at 110 % of the air mass flow at site rated power. See Figure 12.

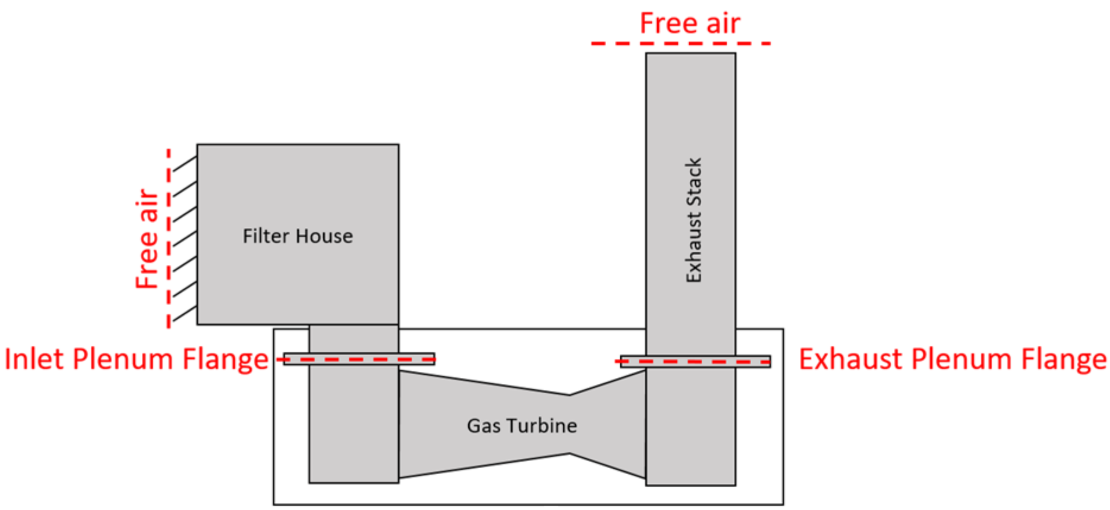


Figure 12—Inlet and Exhaust System Pressure Drop Planes

NOTE For gas turbines that operate over a wide range of air temperatures, the maximum pressure drop of new and clean air filters at the lowest air temperature can be higher than at 110 % air mass flow at site rated power.

7.7.2.1.3.2 The inlet system (from free ambient air through to the upstream flange of the inlet plenum, excluding any inlet cooling) shall have a maximum total pressure drop of 6 in. of water (1.5 kPa) with dirty air filters (at high differential pressure alarm set point) at 110 % of the air mass flow at site rated power (see Figure 12).

• **7.7.2.1.4** If specified, gas detectors shall be provided to monitor combustion air (see 7.8.4.19) and trip the gas turbine (see Table 2).

NOTE For gas detection within the filter house, the gas detection system reaction time is not always fast enough and that other measures (e.g. gas detector further away from the gas turbine inlet) could be employed to initiate safe shutdown, prior to the ingestion.

7.7.2.1.5 Provisions shall be made to permit maintenance of inlet filter media during operation of the gas turbine, excluding the last stage of filter media.

7.7.2.1.6 Thermocouples, bolts, rivets, or other fasteners that can become loose in the air stream shall not be used in the inlet system downstream of the final stage of filtration.

7.7.2.1.7 If screens downstream of inlet air filters are required by the gas turbine manufacturer, screens shall be clamped in position with captive locking devices such that no bolts, nuts, or clamps can enter the gas turbine.

7.7.2.1.8 If inspection ports or doors are in a location that allows unfiltered air to enter the gas turbine, an alarm shall notify operators when they are open. Bolted man ways and inspection ports are excluded from this requirement.

7.7.2.2 Inlet Filters

7.7.2.2.1 A drain system shall be provided in the dirty air side to remove water caught within the air intake.

7.7.2.2.2 A drain system shall be provided to ensure that any water caught on the clean side is drained away, preventing the risk of re-entrainment into the airstream.

7.7.2.2.3 Where the chance of ice formation within the drain exists, provision for installing heat tracing shall be provided.

7.7.2.2.4 If a final stage vane separator is used on the clean air side, a drain system shall be provided.

7.7.2.2.5 All drains on the clean side of the filter system shall be permanent, free flowing under gravity, uninterrupted, and not allow air ingress (e.g. trap) under all pressure conditions.

NOTE Uninterrupted means that there are no valves.

7.7.2.2.6 VDDR [see Annex B, item 54)] shall include the filter wet burst pressure and wet burst test procedure, the initial pressure drop at site rated power, and the efficiency per EN 779 for filters up to F9 or EN 1822:2012 for filters E10 or better. See 9.2.3.2 m).

NOTE There is no industry accepted definition of wet burst pressure or standard test procedure.

7.7.2.2.7 The point where combustion air and ventilation air enter the inlet air filtration system will be an unclassified location (nonhazardous location) in accordance with API 500 or API 505.

7.7.2.2.8 The point where combustion air and ventilation air enter the inlet air filtration system will be positioned and oriented to avoid ingestion of substances other than air (e.g. smoke, sand, dust, lube oil vapors, exhaust, gas vent discharge).

7.7.2.3 Filter System Selection and Design

7.7.2.3.1 The inlet air filtration system shall be designed for site environmental conditions per 6.6.

7.7.2.3.2 The inlet system shall be designed to prevent objects larger than 0.5 in. (12.7 mm) diameter from entering the first-stage air inlet.

7.7.2.3.3 In the tropical and offshore environments, a vane separator shall be used as the first stage of filtration, otherwise louvers or weather hoods may be used.

7.7.2.3.4 Filter media shall be 100 % synthetic material (fiberglass or polymer fibers).

NOTE Filters containing cellulose are negatively affected by direct contact with water or humid air; however, blended media with up to 90 % cellulose has been used successfully in arid environments (see Annex F).

7.7.2.3.5 Unless otherwise specified, the final element filter class shall be F9 in accordance with EN 779 at 110 % of the air mass flow (including any required ventilation air, inlet bleed heating, and anti-icing) at site rated power.

NOTE E12 is becoming more common and reduces fouling and extends water wash intervals.

7.7.2.3.6 For cartridge filters that will be mounted horizontally, the vendor shall demonstrate the integrity of all seals (e.g. tubesheet and filter-to-filter interfaces) when cartridges are fully loaded in the installed position.

7.7.2.3.7 The inlet filter house external walls shall have a minimum thickness of $^{3}/_{16}$ in. (5 mm).

7.7.2.3.8 The filter house internal structure (e.g. stiffing frames, bracing) shall have a minimum thickness of $^{1}/_{8}$ in. (3 mm).

7.7.2.3.9 All external joints shall be gasketed and watertight per IEC 60529, IP 56.

7.7.2.3.10 All external joints, downstream of the first stage of filter media, shall be gasketed and airtight.

7.7.2.3.11 The air inlet system shall not utilize mastics and sealing compounds.

7.7.2.3.12 The inlet filter house shall be modular construction with each module factory assembled, with all required wiring, piping, and structural supports.

7.7.2.3.13 Each filter house module shall have lifting lugs per 7.4.3 that permit it to be loaded, unloaded, assembled, and lifted into its final position.

7.7.2.3.14 The last stage particulate filter shall be designed for a minimum wet collapse differential pressure of 3.7 kPa (15 in. water).

NOTE Wet collapse differential pressure is the minimum differential pressure measured on a new filter that is 100 % saturated with dirt and water that experiences irreversible damage.

7.7.2.3.15 All inlet system components (e.g. filter holding frames, mist eliminators, bug screens), ducting, air filter house) downstream of the last stage particulate filter shall be designed for a minimum collapse differential pressure of 3 kPa (12 in. water).

7.7.2.3.16 The inlet ducting and air filter assembly shall be designed or protected from damage caused by gas generator surge (see F.3.3.7.9).

7.7.2.3.17 The filter house internal lighting system shall:

a) conform to 6.5.3;

b) conform to 6.5.4 and be suitable for outdoor use;

• c) utilize specified power supply [normal vs. UPS; see 7.7.2.3.17 h)];

d) provide in-service illumination level 150 lux or higher;

e) provide emergency egress illumination level of 50 lux or higher;

f) be operated by switches located outside and within 1 m of all filter house access doors and utilize three-way switches when there are two or more filter house doors;

g) preserve the filter house air flow distribution requirements;

h) have an emergency lighting system for power loss.

7.7.2.3.18 For land-based applications, the lowest part of the filter house air entrance shall be elevated a minimum 6 m (20 ft) above ground.

NOTE Provide consideration for conditions such as accumulation of snow (e.g. snow drift).

7.7.2.3.19 For offshore applications where the filter house is not extended beyond platform edge, the lowest part of the filter house air entrance shall be elevated a minimum 4.6 m (15 ft) above solid deck.

• **7.7.2.3.20** For offshore applications where the filter house is extended beyond platform edge, the lowest part of the filter house air entrance shall be elevated a specified distance above grade.

• **7.7.2.3.21** If specified, the filter system shall be self-cleaning.

7.7.2.4 Self-cleaning Systems

7.7.2.4.1 For self-cleaning (pulse cleaning) systems, the proposal shall include system design pressure, maximum and minimum pulse pressures, temperature and air quality requirements, maximum compressed air flow consumption rate, percentage of filters pulsed together, the pulse sequence and cycle time, number of filters per valve, the dust evacuation system configuration, the type of valve firing (e.g. solenoid, pilot valve), and expected header and piping life. See 9.2.3.2 m).

7.7.2.4.2 The self-cleaning system shall include an automatic control with a manual start and stop switch and a cycle counter.

• **7.7.2.4.3** If specified, self-cleaning systems shall have independent isolation valves and drain valves fitted to each air distribution header.

7.7.2.4.4 The self-cleaning systems shall be, as a minimum, made of 316 or 316L stainless steel or better. A suitable aluminum alloy (marine grade) pulse valve bodies may be used.

7.7.2.4.5 The air inlet house manual pulse controls shall be readily accessible from grade level, next to the access door on the filter house, or control room.

7.7.2.4.6 The pulse air system shall be fitted with a coalescing filter to remove liquid from the air.

• **7.7.2.4.7** If specified, the vendor shall provide a relative humidity sensor.

a) When the gas turbine is running, the sensor shall automatically activate the cleaning cycle each time the relative humidity exceeds 60 %.

b) When the gas turbine is stopped, the sensor shall automatically activate the cleaning cycle once, after each stop, before the relative humidity exceeds 60 %.

c) The relative humidity sensor may be used for other performance calculations.

NOTE High humidity and blowing dust can cause severe caking of material on the filter elements.

7.7.2.5 Filter Instrumentation and Monitoring

7.7.2.5.1 The gas turbine inlet differential pressure alarm and shutdown shall be based on the total pressure drop across all filter stages.

7.7.2.5.2 Differential pressure measurement shall be included across each stage of replaceable filtration.

7.7.2.5.3 Instrumentation and electrical devices, which are internal to the filter housing, shall be wired to terminal strips located in junction boxes (see 7.5.1.2 and 7.5.8.21.6) mounted on the outside of the filter housing.

7.7.2.6 Filter Maintenance Considerations

• **7.7.2.6.1** If specified, inlet filters shall be replaceable during operation of the gas turbine, with exception of the final filter.

7.7.2.6.2 Proposal shall include the estimated frequency of maintenance for the operating conditions (see 6.6) and fuel composition (see 7.9.2 and 7.9.4). See 9.2.3.2 m).

7.7.2.7 Inlet Silencers

7.7.2.7.1 Silencer attenuation shall meet the noise limitations of 6.3.

7.7.2.7.2 Silencers flow path shall be of welded 316L stainless steel and shall be flanged.

7.7.2.7.3 The construction of the silencer baffles shall prevent the baffle packing material from entering the gas stream.

7.7.2.7.4 Perforated-plate elements for silencers shall be constructed of ASTM A240 Type 316L stainless steel.

7.7.2.7.5 Silencers shall be designed to prevent damage from acoustical and mechanical resonances and differential thermal expansion.

7.7.2.7.6 Proposal shall include details for the silencers, description of the acoustical material in the casing and baffles. See 9.2.3.2 m).

7.7.2.7.7 Lifting provisions for handling shall be incorporated on the silencers, per 7.4.3.

7.7.2.8 Gas Generator Air Compressor Bleed System

• **7.7.2.8.1** Bleed air, for utilization outside the gas turbine, shall be provided at the specified pressure, temperature and flow.

NOTE Some gas turbines cannot provide any bleed air and others are limited in the flow rate and pressure.

7.7.2.8.2 Proposal shall describe the flow rate and pressure of bleed air available for use by the purchaser and the effect on gas turbine performance. See 9.2.3.2 m).

7.7.2.8.3 Bleed air shall not be extracted from sealing or cooling air lines.

7.7.2.8.4 Mechanical and structural support systems for the gas generator compressor bleed system shall be provided.

7.7.2.8.5 All gas generator compressor bleed valves shall have position indicators.

7.7.2.8.6 Bleed piping design and routing external to the gas turbine enclosure shall be approved by the purchaser.

• **7.7.2.8.7** If specified, bleed valve procurement shall not be initiated until bleed valve design has been approved by the purchaser.

7.7.2.8.8 The gas turbine shall not be adversely affected by flow-induced resonance associated with the gas generator compressor bleed system.

7.7.2.9 Inlet Coolers and Heaters

7.7.2.9.1 General

7.7.2.9.1.1 The cooling or heating system shall be designed for a maximum total pressure drop of 0.25 kPa (1 in. water) with 110 % of the air mass flow (including any required ventilation air, inlet bleed heating, and anti-icing) at site rated power. This pressure drop is in addition to the maximum total pressure drop allowed in 7.7.2.1.3. See Annex G for additional information.

7.7.2.9.1.2 Proposal shall include inlet cooler and/or heater construction details. See 9.2.3.2 m).

7.7.2.9.1.3 Proposal shall describe all controls supplied with the cooling and/or heating system. See 9.2.3.2 m).

7.7.2.9.1.4 Proposal shall quantify any impact of inlet air heating or cooling systems to gas turbine performance and emissions characteristics. See 9.2.3.2 m).

7.7.2.9.1.5 Inlet air cooling and heating systems shall be instrumented to permit verification of system performance.

7.7.2.9.2 Evaporative Coolers

7.7.2.9.2.1 General

7.7.2.9.2.1.1 All water shall be fully evaporated before entering the gas turbine, except during water washing.

NOTE Overspray (free water entering the compressor) can impact the gas generator surge margin and can damage the compressor blading.

7.7.2.9.2.1.2 The evaporative cooler shall be installed downstream of the final inlet air filtration stage, followed by a mist eliminator to prevent condensed water droplets from entering the gas turbine. The cooler system is the heat exchanger and mist eliminator.

7.7.2.9.2.1.3 The evaporative cooler system shall automatically shutdown at the gas turbine manufacturer's recommended set point [e.g. 13 °C (55 °F)] and alarm at the gas turbine manufacturer's recommended set point [e.g. 15 °C (60 °F)].

7.7.2.9.2.1.4 All evaporative cooler housing and internal structural support shall be, a minimum, of 316 or 316L stainless steel.

7.7.2.9.2.1.5 All piping shall be, as a minimum, in accordance with Table 3.

7.7.2.9.2.1.6 The cooler housing and drainage design shall not allow water to stand inside the filter house at any time. If winterization is necessary (see 6.6), then low point drains shall be provided to drain all liquids from the entire system.

NOTE 1 Drain system heat tracing is not normally provided by the vendor.

NOTE 2 Continuously draining water sump underneath the evaporative media is allowed.

7.7.2.9.2.1.7 The housing drainage system shall not allow unfiltered air to be drawn into the inlet air stream through the drain piping typically by the installation of a trap.

7.7.2.9.2.1.8 The gas turbine vendor shall specify the minimum quality, pH, and quantity of water required for satisfactory cooler system operation.

7.7.2.9.2.1.9 Proposal shall include cooler efficiency and the pressure drop across the cooler system under maximum flow conditions. See 9.2.3.2 m).

7.7.2.9.2.2 Wetted Media Inlet Air Evaporative Coolers

• **7.7.2.9.2.2.1** If wetted media evaporative coolers are specified, the wetted media system shall include the following: cooler media, circulation pump, sump drains, and corrosion-resistant metal mist eliminator.

7.7.2.9.2.2.2 A manway or removable panel with minimum of 600 mm × 600 mm (24 in. × 24 in.) or 600 mm (24 in.) in diameter opening shall be provided for complete access both upstream and downstream of the cooler media and mist eliminator sections.

7.7.2.9.2.2.3 Wetted media control system shall include:

a) capability to locally and remotely switch the system from either manual, off or automatic;

b) monitoring for flow or pressure on evaporative cooler water inlet;

c) sump water conductivity monitoring and appropriate action.

7.7.2.9.2.3 Atomizing Spray Inlet Air Evaporative Coolers

• **7.7.2.9.2.3.1** If atomizing spray inlet air evaporative coolers are specified, the atomizing nozzles and pump shall be supplied.

7.7.2.9.2.3.2 Manways or removable panels with minimum of 600 mm × 600 mm (24 in. × 24 in.) or 600 mm (24 in.) in diameter. Opening shall be provided for atomizing nozzle inspection and replacement.

7.7.2.9.2.3.3 All atomizing nozzles shall be retained such that they cannot become loose and enter the gas turbine. Lock wire may be used.

7.7.2.9.2.3.4 The atomizing spray control system shall include:

a) capability to locally and remotely switch the system from either manual, off or automatic;

b) monitoring for flow or pressure on evaporative cooler water inlet.

7.7.2.9.3 Inlet Air Cooling by Heat Exchanger

• **7.7.2.9.3.1** If specified, a heat exchanger for the purpose of cooling the inlet air temperature for gas turbine performance enhancement shall be provided.

7.7.2.9.3.2 The heat exchanger shall be located downstream of the final inlet air filtration stage, followed by a mist eliminator to prevent condensed water droplets from entering the gas turbine. The cooler system is the heat exchanger and mist eliminator.

7.7.2.9.3.3 Construction of the exchanger internals shall utilize only corrosion-resistant metals.

7.7.2.9.3.4 The heat exchanger shall be made of, as a minimum, 316 or 316L stainless steel. Fins may be aluminum.

• **7.7.2.9.3.5** The cooler system shall be designed within the air-side operating conditions (see 6.6) and specified coolant-side conditions to provide guaranteed gas turbine performance.

7.7.2.9.3.6 Proposal shall include utility requirements, pressure drop across the cooler, the performance of the cooler system in terms of inlet temperature reduction, as well as effect on gas turbine shaft output, heat rate, and air emissions. See 9.2.3.2 m).

7.7.2.9.4 Inlet Air Heating

• **7.7.2.9.4.1** If specified, an inlet air heating system shall be installed to heat inlet air for gas turbine anti-icing, performance, or emissions control. Inlet air heating may be by:

a) heat exchanger;

b) electric heater;

c) gas generator compressor bleed.

7.7.2.9.4.2 The inlet air heating system shall minimize localized snow melting that can aggravate ice buildup on the filters or contribute to downstream icing.

7.7.2.9.4.3 For heat exchanger systems (see 7.7.2.9.4.1), the proposal [see 9.2.3.2 m)] shall identify:

a) heating fluid;

b) heating fluid flow;

c) heating fluid temperature and pressure.

7.7.2.9.4.4 The heat exchanger shall be made per 7.7.2.1.1. Nonmetallic components shall not be used internal to the heater.

7.7.2.9.4.5 If a gas generator compressor bleed system is required by 7.7.2.8.1, the proposal shall describe the usage of bleed air (pressure, flow, and temperature) for the site conditions (see 6.6). See 9.2.3.2 m).

7.7.2.9.4.6 The heater shall be designed for the site conditions (see 6.6).

7.7.2.9.4.7 The proposal [see 9.2.3.2 m)] shall include:

a) utility requirements;

b) air side pressure drop;

c) performance of the heater in terms of inlet temperature increase;

d) impact on gas turbine power, heat rate, exhaust emissions, sound power level, and sound pressure level.

7.7.2.9.4.8 The control system shall include capability to locally and remotely switch the system from either manual, off or automatic.

7.7.2.9.4.9 Inlet air heating systems and hot air distribution manifolds shall be installed upstream of the gas turbine inlet air filter elements. The location of the bleed systems that are not used for anti-icing (e.g. emissions turndown) may be at the discretion of the gas turbine manufacturer.

NOTE Air distribution manifolds are installed upstream of the gas turbine inlet filters to mitigate risk from flow anomalies caused by ice or snow plugging of the filters.

7.7.2.9.4.10 Inlet air heating system controls shall prevent overheating of any air inlet system components over the entire speed and load range and when the gas turbine is not operating.

7.7.2.9.4.11 Proposal [see 9.2.3.2 m)] and VDDR [see Annex B, item 54)] shall describe any restrictions on air filter replacement while inlet air heating system is operating or still hot.

7.7.2.10 Wash Systems

7.7.2.10.1 An offline wash system shall be provided, including all wash nozzles, controls, piping, tubing, tanks, pumps, and heater to perform offline washing of the gas generator compressor.

• **7.7.2.10.2** If specified, an online wash system shall be provided, including all wash nozzles, controls, piping, tubing, tanks, pumps, and heater to perform regular online washes without operator intervention. Operator intervention does not include filling the tank with wash fluids.

• **7.7.2.10.3** Vendor shall supply the specified number of portable wash carts and fixed wash skids.

7.7.2.10.3.1 Portable wash carts shall be as follows.

a) Portable wash carts shall be packaged with all wash system pumps, tanks, heaters, piping, tubing, and controls on a portable wheeled cart.

b) The portable wash cart shall have lockable wheels.

c) The portable wash cart shall include an integral lifting lug or pad eye in accordance with 7.4.3 for a single-point lift of a full wash cart.

7.7.2.10.3.2 Fixed wash skids shall be as follows.

a) Fixed wash skids shall be packaged with all wash system pumps, tanks, heaters, piping, tubing, and controls on a common skid that is separate from the main gas turbine skid.

b) The interconnecting piping between a fixed wash skid and the tank will be provided by the purchaser.

7.7.2.10.4 Unless otherwise specified, the wash tank shall be sized for at least one complete wash and rinse process, assuming 30 ft (10 m) of interconnecting piping to the gas turbine.

NOTE The length of interconnecting piping impacts the sizing of the tank, heater and pump. The volume of water supplied to the gas turbine is reduced by volumetric capacity of the interconnecting piping. The pressure drop in the interconnecting piping reduces the capacity of some types of pumps. The 30 ft is just an assumption, since the actual distance is probably not precisely known at the time of purchase.

7.7.2.10.5 Control logic shall prevent incorrect initiation of online and offline washing.

7.7.2.10.6 All wash system wetted metallic components shall be in accordance with Table 3 and shall be designed and installed so that no parts can come loose and enter the gas turbine.

7.7.2.10.7 Proposal shall fully describe water washing system, including wash water quality and detergent requirements (including Material Safety datasheets), operational procedures, temperature limits, and estimated detergent and water quantity requirements. See 9.2.3.2 m).

7.7.2.10.8 VDDR [see Annex B, item 42 f)] shall fully describe all required nonroutine washing procedures (e.g. prior to startup).

7.7.2.10.9 All wash systems shall not damage sensitive components.

7.7.2.11 Combustion Air Ductwork

7.7.2.11.1 Welding and Bolting

7.7.2.11.1.1 All combustion air ducting, internal manifolds, supporting structures, and metallic gas turbine plenums shall be continuous welded construction.

7.7.2.11.1.2 Stitch welding may only be used for internal perforated plates used to contain insulating material.

7.7.2.11.1.3 Bolted connections between the air filters and the gas turbine may be used if held captive. Two acceptable methods are:

a) welding 33 % of the outside diameter of the nut or head to the support;

b) welding 50 % the circumference of the bolt shank to the inside diameter of the nut.

7.7.2.11.1.4 All stitch welding around the perimeter of perforated plates shall conform to the following.

a) All stitches shall be fillet welds to supporting framework that is at least 2 mm thick on inlet systems and 3 mm thick on exhaust systems.

b) All stitch welds shall be 30 mm (1.2 in.) or greater in length (see dimension “C” in Figure 13).

c) The gap between adjacent stitch welds shall not exceed 70 mm (2.75 in.) (see dimension “B” in Figure 13).

d) Stitch welds shall not overlap stitches on adjacent perforated plates.

e) Stitch welds shall wrap around and extend at least 100 mm (4 in.) from the corner on both sides of all corners (see dimension “A” in Figure 13).

f) All stitch welds shall be at least 5 mm (0.2 in.) from perforations (see dimension “F” in Figure 13).

7.7.2.11.1.5 All nonperimeter perforated plate welds shall conform to the following:

a) All stitches shall be fillet welds to supporting framework that is at least 2 mm thick on inlet systems and 3 mm thick on exhaust systems.

b) All welds shall be around the perimeter of a hole that is at least 12 mm (0.5 in.) diameter (see dimension “D” in Figure 13).

c) All welds shall be at least 5 mm (0.2 in.) from perforations (see dimension “E” in Figure 13).

d) Blind plug welds shall not be used.

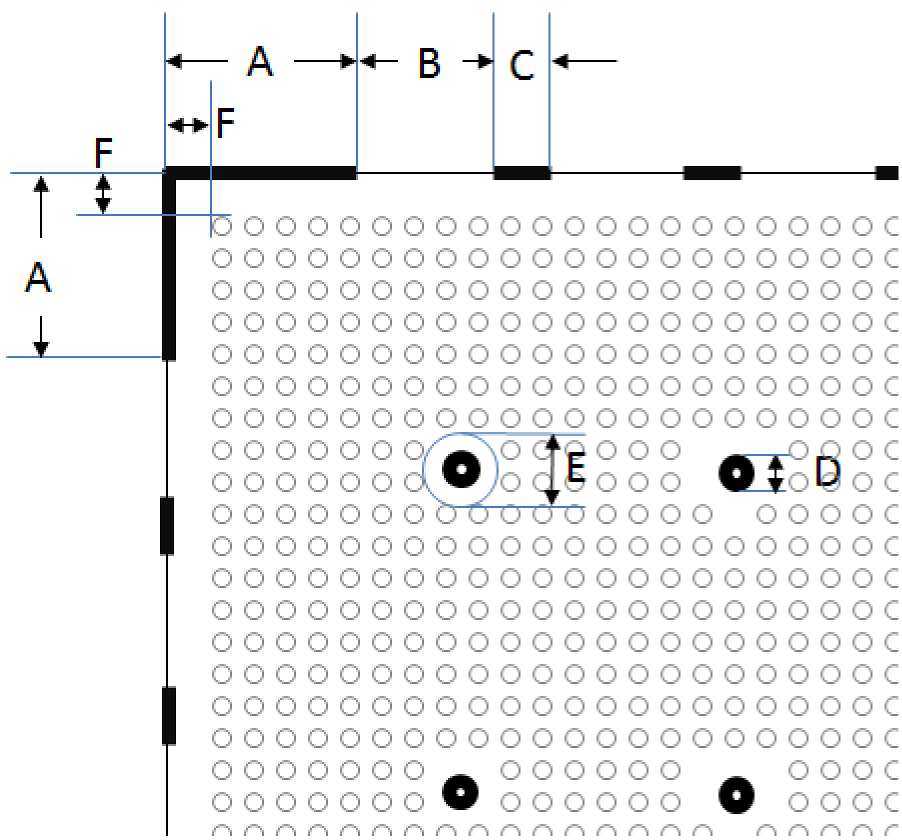


Figure 13—Stitch Welding of Perforated Plates

7.7.2.11.2 The plate and sheet used for internal perforated plates and exhaust liners shall not be less than 1.5 mm (0.06 in.) thick.

7.7.2.11.3 The number of flanged connections in the ducting shall be minimized.

7.7.2.11.4 The inlet ductwork shall be designed to use gasketed joints between components.

7.7.2.11.5 Mastics and sealing compounds shall not be used in the gas path downstream of the first air filter element.

7.7.2.11.6 The ductwork arrangement shall minimize the number of changes in direction and flow anomalies.

7.7.2.11.7 Air flow distribution at the gas turbine inlet shall conform to gas turbine manufacturer's guidelines. This includes filters, ductwork, silencers, heat exchangers, and transition design and arrangement. Turning vanes may be used to assure uniform flow distribution.

7.7.2.11.8 Turning vanes shall be designed to reduce turbulence and avoid resonance.

7.7.2.11.9 Turning vanes shall be attached to the duct by a continuous weld.

7.7.2.11.10 Air flow distribution at the air filter elements shall conform to air filter manufacturer's guidelines.

7.7.2.11.11 Inlet and exhaust ductwork shall not transmit unacceptable forces or moments to the gas turbine flanges at all operating and nonoperating conditions. The gas turbine manufacturer shall advise acceptable forces and moments to the subvendor of ductwork [see Annex B, item 1)].

7.7.2.11.12 Inlet and exhaust ductwork shall allow adequate lateral and axial movement for temperature changes and construction tolerances (see 7.7.3.1.1).

7.7.2.11.13 Inlet and exhaust ductwork shall be designed to remain stationary when duct sections are removed to provide access for maintenance.

7.7.2.11.14 The plate and sheet used for inlet ductwork shall not be less than 5 mm (0.2 in.) thick.

7.7.2.11.15 The plate and sheet used for exhaust ductwork shall not be less than 6 mm (0.24 in.) thick.

7.7.2.11.16 Inlet and exhaust ductwork shall be designed to eliminate vibration-induced damage.

7.7.2.11.17 For all horizontal ducting, width or height larger than 910 mm (36 in.), the ductwork shall be designed to safely support at least two people working on top of the ducting without damage to the ductwork or excessive deflection. One applied load of 2.2 kN (500 lbf) over 0.1 m^2 (1 ft^2) addresses two people.

7.7.2.11.18 For ducting with diameter, width or height larger than 910 mm (36 in.), the ductwork shall be designed to safely support at least two people working inside the ducting without damage to the ductwork or excessive deflection. One applied load of 2.2 kN (500 lbf) over 0.1 m^2 (1 ft^2) addresses two people.

7.7.2.11.19 For ducting with diameter, width or height larger than 910 mm (36 in.), manways shall be provided in each duct adjacent to the gas turbine inlet and exhaust flanges to allow cleaning and inspection of the entire duct system. These may be the same means of access required by 6.7.15.

7.7.2.11.20 Implosion Doors

7.7.2.11.20.1 Unless otherwise specified, implosion doors shall not be used on the inlet air system.

7.7.2.11.20.2 If implosion doors are used, the system shall be designed such that ice shall not prevent proper door operation, and such that ice shall not be ingested if the door operates. Heat tracing may be used.

7.7.3 Exhaust Systems

7.7.3.1 Exhaust System Design

7.7.3.1.1 The exhaust system (from gas turbine exhaust plenum flange to free air; see Figure 12) shall be designed for the following at 110 % of the air mass flow at site rated power:

a) a maximum total pressure drop of 6 in. of water (1.5 kPa) without a heat recovery system, or

• b) if a heat recovery system is specified, the maximum total pressure drop shall be 12 in. of water (3 kPa).

7.7.3.1.2 Exhaust system shall be designed for static and dynamic load scenarios, including:

a) thermal;

b) mechanical;

c) flow induced (acoustic/resonance);

d) surface transport and lifting (see 6.5.14);

e) marine (barge transport and/or shipboard or offshore floating application; see 7.7.1.6).

7.7.3.1.3 The basic material for construction of the exhaust system shall be compatible with the exhaust gases (including condensate after gas turbine stop) expected from the fuel compositions (see 7.9.2 and 7.9.4) and operating conditions (see 6.6).

7.7.3.1.4 The exhaust system shall be designed for the minimum ambient temperature as well as the maximum design exhaust temperature.

a) Material shall be selected such that the nil-ductility temperature is lower than the minimum site temperature.

b) Material shall be selected such that the risk of carburization and oxidation are mitigated at the maximum design exhaust temperature, for example:

   1) if the minimum site ambient temperature is above the nil-ductility temperature of AISI 1020 and the maximum design temperature is below 455 °C (855 °F), AISI 1020 or an equal or better material may be used;

   2) if the minimum site ambient temperature is above the nil-ductility temperature of AISI 1020 and the maximum design temperature is above 455 °C (855 °F), ferritic stainless steel or an equal or better material may be used.

c) Material selection shall prevent stress corrosion cracking.

7.7.3.1.5 The heat recovery system will be supplied by the purchaser.

7.7.3.2 Exhaust Silencer

7.7.3.2.1 Silencer attenuation shall meet the noise limitations of 6.3.

7.7.3.2.2 Exhaust silencer material of construction shall meet 7.7.3.1.3.

7.7.3.2.3 Unless otherwise specified, as a minimum, perforated plates or sheets shall be constructed of 409 series stainless steel or equal.

7.7.3.2.4 Exhaust silencer acoustic and thermal insulation, whether externally or internally applied, shall be suitably attached and captured to prevent its deterioration and subsequent attachment and capture failure.

7.7.3.2.5 The exhaust silencer shall incorporate lifting and handling provisions (see 7.4.3).

7.7.3.2.6 The exhaust silencer shall incorporate a support interface suitable for the associated design loads.

7.7.3.3 Exhaust Ducting

7.7.3.3.1 Exhaust duct material of construction shall meet 7.7.3.1.3.

• **7.7.3.3.2** Atmospheric relief devices and associated dampers shall be included as specified. Purchaser will consider leakage rate when routing and locating the discharge.

• **7.7.3.3.3** Exhaust emissions test ports shall be provided and located in accordance with specified emissions codes, and permit requirements.

7.7.3.3.4 The design temperature of the exhaust expansion joint, its auxiliaries and the mating flanges shall be suitable for service at the maximum design exhaust temperature.

7.7.3.3.5 The exhaust expansion joints shall be either metal or high-temperature fabric, multilayered and reinforced with stainless steel wires.

7.7.3.3.6 All bolting, duct, and joint components in contact with the fabric expansion joint shall have rounded edges to avoid abrasion or tearing of the material. Expansion joint components that may be used include guide rods, metal expansion joints, slide plates, and stops.

7.8 Insulation, Weatherproofing, and Fire Protection

7.8.1 Insulation

7.8.1.1 Gas turbine casings or components in a personnel access area shall have suitable insulation or guards so that no exposed surface exceeds a temperature of 65 °C (150 °F).

NOTE 1 Interior of the noise enclosure, areas that are not normally accessible, components protected by guards, and areas behind personnel barriers are not personnel access areas.

NOTE 2 ISO 13732 explains the method for the assessment of responses to contact with hot surfaces.

7.8.1.2 Insulation and guards shall be designed so that routine maintenance may take place without damage being done to the insulation.

• **7.8.1.3** Additional insulation and guarding shall be furnished if specified (e.g. heat conservation in vent and fuel lines). Proposal shall detail insulation and guarding [see 9.2.3.2 m)].

NOTE Aeroderivative engines typically do not have external insulation applied.

7.8.1.4 Where the application of insulation is not practical or interferes with unit design or operation, personnel barriers (e.g. enclosure) may be utilized (with the approval of the purchaser) to protect personnel from excessive temperature. These barriers shall be readily removable for ease of maintenance or fitted with suitable access points.

7.8.1.5 Insulation materials for enclosure roof and wall panels shall be resistant to moisture, fire, insects, vermin, and oil wicking.

7.8.2 Weatherproofing

7.8.2.1 The gas turbine package, including all auxiliaries, shall be weatherproofed for operation at the site conditions (see 6.6).

7.8.2.2 Exterior enclosure doors, windows, walls, and roofs shall conform to IEC 60529 IP 66 or NEMA 4X ingress protection requirements.

7.8.2.3 Enclosure horizontal surfaces exposed to the weather shall not have depressions, voids, and crevices where liquid may accumulate.

7.8.3 Fire Protection

7.8.3.1 All enclosures shall be furnished with a fire protection system consisting, as a minimum, of the following:

a) fire detection system;

b) gas detection system suitable for the detection of vapor/gas from the fuels system(s);

NOTE H_2S detectors may be required for sour fuels.

c) fire suppression system.

7.8.3.2 Fire suppression system shall be the specified type and comply with the specified standard:

• a) NFPA 2001 (clean agent systems);

• b) ISO 14520 (clean agent systems);

• c) NFPA 750 (water mist systems);

• d) NFPA 12 (carbon dioxide systems);

• e) ISO 6183 (carbon dioxide systems); or

• f) NFPA 2010 (aerosol systems).

7.8.3.3 The primary method of actuation of the suppression system shall be automatic.

7.8.3.4 Each fire suppression system shall be capable of manual actuation from stations located externally on each of the long sides of the enclosure.

• a) If specified, an additional manual actuation station shall be located at the local control panel.

• b) If specified, an additional manual actuation station shall be located inside the control room.

c) The manual actuation location shall conform to NFPA 12, NFPA 72, and NFPA 750.

7.8.3.5 Provisions shall be made for exercising the fire detection and protection system without discharging the fire suppression medium.

7.8.3.6 The fire detection system shall be in accordance with NFPA 72.

7.8.3.7 Heat-sensing fire detection shall be provided.

NOTE Additional levels of detection, such as optical flame detection, can be considered.

7.8.3.8 Fire detection system shall alarm and trip the gas turbine (see 7.5.5.1).

• **7.8.3.9** The gas detection system shall be in accordance with NFPA 72 or IEC 60079-29-1 and IEC 60079-29-2, as specified.

7.8.3.10 All fire suppression and detection devices utilized within the enclosure shall be designed to operate throughout the entire range of operational service conditions encountered within the enclosure.

7.8.3.11 The fire and gas system shall be a permissive for starting the gas turbine (including the complete unit test; see 8.3.5.2).

7.8.3.12 Gas detectors shall be provided to monitor enclosure ventilation system air exhaust.

• **7.8.3.13** If specified, gas detectors shall be provided to monitor enclosure ventilation system air intake. If enclosure air ventilation is drawn from a combustion air system, downstream of gas detection (see 7.7.2.1.4), then an additional gas detector is not required.

7.8.4 Enclosures

7.8.4.1 Unless otherwise specified, gas turbine enclosure(s) shall be provided.

• **7.8.4.2** If specified, auxiliary equipment enclosure(s) shall be provided. Auxiliary equipment enclosure systems shall include a ventilation system, gas detection system, fire detection, fire protection systems, and any associated isolation devices.

• **7.8.4.3** If specified, driven equipment enclosure(s) shall be provided. Driven equipment enclosure systems shall include a ventilation system, gas detection system, fire detection, fire protection systems, and any associated isolation devices.

NOTE Generators are generally enclosed, whereas compressors generally are not.

7.8.4.4 Enclosure systems may be either on baseplate or off baseplate.

7.8.4.5 All enclosures shall include walls and roof that isolate the space occupied by the enclosed equipment on its baseplate.

7.8.4.6 All enclosure drip pans, walls, ceilings, and doors (including all fasteners and wall and ceiling structural members) shall be, as a minimum, 316 or 316L stainless steel.

7.8.4.7 All (e.g. gas turbine, driven, auxiliary) enclosures shall conform to insulation (see 7.8.1), weatherproofing (see 7.8.2), and acoustical (see 6.3) requirements.

7.8.4.8 All gas turbine enclosures shall conform to fire protection system (see 7.8.3) requirements.

7.8.4.9 A minimum of two personnel doors, one on each of the longest sides of each enclosure, shall be provided to permit access for routine maintenance and inspection.

7.8.4.10 All enclosure door seals shall be selected to be resistant to ozone degradation and withstand normal use without loss of sealing.

7.8.4.11 All enclosure doors shall have latching devices that can hold the door in the closed or open position.

7.8.4.12 All enclosure personnel doors shall open from the inside without keys, tools, or special knowledge.

a) A push only device shall be used in lieu of a handle or knob that rotates.

b) The ability to open form the inside shall not be defeated by any locking feature.

7.8.4.13 All enclosure door hinges, latches, and handles shall be heavy duty and, as a minimum, 316 or 316L stainless steel with a nongalling pin that is corrosion resistant in site environmental conditions.

7.8.4.14 Unless otherwise specified, all enclosure personnel doors shall be fitted with a window that is not less than 300 mm (12 in.) square or 300 mm (12 in.) diameter.

7.8.4.15 All enclosure windows shall be located so that equipment can be viewed during normal operation.

NOTE It can be impractical to locate windows where they provide a good view of all the equipment.

7.8.4.16 All enclosure windows shall use safety glass configured and installed to retain the glass in the event of over-pressure or over-temperature. If required for noise abatement, two safety panes, separated by a dead air space may be used.

7.8.4.17 Enclosures with internal ultraviolet detectors shall mitigate the risk of false detection from light sources from outside the enclosure. Covers or shutters on enclosure windows may be used.

7.8.4.18 Conduits, fire prevention systems, gas detection, etc., shall not be attached to the underside of the roof or any other panels removed for maintenance.

7.8.4.19 Ventilation

7.8.4.19.1 Enclosure ventilation systems shall include a fan-driven forced ventilation and purging air system designed to provide 100 % of the ventilation and purging load in the most severe climatic/load conditions while at 100 % of design load.

• **7.8.4.19.2** Enclosure ventilation system shall include the specified fan redundancy and pressurization requirements (e.g. none, 2 × 100 %, 3 × 50 %).

7.8.4.19.3 The ventilation system shall maintain all components inside the enclosure within the components' application limits.

NOTE Cold ambient applications can require tempering/heating ventilation air.

7.8.4.19.4 Ventilation system shall include air filtration and any silencing equipment required to meet noise requirements (see 6.3). Ventilation air may be taken from the gas turbine inlet air filtration system.

7.8.4.19.5 Ventilation systems shall be equipped with dampers on both the enclosure inlet and outlet; both dampers shall automatically close no later than fire suppression system activation and provide an acceptable fire suppressant leakage rate (see 7.8.3.2).

7.8.4.19.6 If cooldown ventilation is required to prevent damage to any equipment or instrumentation within the enclosure, a UPS-powered fan shall be provided.

7.8.4.19.7 The adequacy of the ventilation system to mitigate flammable gas accumulation shall be established by the vendor. The verification system used by the vendor to show that there are no dead spaces within the enclosure ventilation systems shall be in accordance with ISO 21789.

7.8.5 Mechanical Handling within Package

7.8.5.1 Proposal shall state component size and weight, with its associated access (space) and lifting requirements for both routine and major maintenance. See 9.2.3.2 m).

7.8.5.2 Unless otherwise specified, all mechanical handling equipment shall be supplied to perform the gas turbine manufacturer's recommended maintenance activities during the service life (see 6.1.2) for any movable component 25 kg (55 lbm) or heavier. Initial gas turbine package installation handling equipment is excluded.

NOTE Mechanical handling equipment refers to equipment and special tools necessary to lift, lower and transport to the laydown area, the gas turbine (gas generator, power turbine) and gas turbine components associated with maintenance.

7.8.5.3 Proposal shall identify which mechanical handling equipment is included and excluded. See 9.2.3.2 m).

a) All monorails shall be designed and installed in accordance with ASME B30.17.

b) All overhead gantry cranes shall be designed and installed in accordance with ASME B30.2.

c) All hoists shall be designed and installed in accordance with ASME B30.16.

7.8.5.4 All special lifting devices, hooks, counterweights shall be designed in accordance with ASME BTH-1.

7.8.5.5 All testing (e.g. functional, proof load, static, dynamic), inspection (e.g. post testing inspection) and certification shall be carried out to prove the functional integrity of material handling equipment prior to shipment.

7.8.5.6 If material handling equipment needs to be assembled at site, it shall be proof-tested (by vendor) at site as an assembly, before use.

7.8.5.7 Unless otherwise specified, all initial local lifting certifications shall be obtained for all material handling equipment.

7.8.5.8 All testing and inspection results and certifications shall be included in vendor data manuals.

7.8.5.9 A lifting plan shall be supplied for all lifts expected during shipping, installation, maintenance, and de-commissioning.

7.8.5.10 Lifting plans shall include, but not be limited to, description of the equipment to be used and its arrangement, hook height limitations, clearances, gross weight, center of gravity, and laydown area requirements.

7.9 Fuel System

7.9.1 General

7.9.1.1 Fuel Specifications

7.9.1.1.1 Vendor shall supply a complete system for receiving fuel from the purchaser’s system.

• **7.9.1.1.2** The gas turbine fuel system shall be designed and operable with all the specified fuels (see 7.9.2 and 7.9.4), including normal, alternate, or startup fuel gas compositions.

NOTE Composition typically includes hydrocarbons up to at least 12 carbon atoms, water, and contaminants.

7.9.1.1.3 Proposal shall describe the effects of specified (see 7.9.1.1.2) contaminants and corrosive agents on gas turbine operation and maintenance. See 9.2.3.2 m).

NOTE Refer to Annex E and ISO 21789 for additional details on fuel systems.

7.9.1.1.4 The gas turbine manufacturer shall ensure that all aspects of fuel(s) are understood, including constituents, temperatures, pressures, Wobbe index (WI), fuel bound nitrogen levels, storage methods, etc.

7.9.1.2 Fuel Gas System

7.9.1.2.1 Components and Functionality

7.9.1.2.1.1 As a minimum, each gas fuel supply shall include the following functions:

a) manual isolation (see 7.9.1.2.2);

b) leak tight shut-off (see 7.9.1.2.4);

c) automatic fast-acting shut-off (see 7.9.1.2.4);

d) flow control (see 7.9.1.2.3);

e) venting for depressurization between leak tight and automatic fast-acting shut-off valves (see 7.9.1.2.4);

f) venting for pipework and package depressurization (see 7.9.1.2.4 and 7.9.1.2.5);

g) flow control valve, shut-off valve, automatic fast-acting shut-off valve shall close on every shutdown (see items 8 and 10 in Figure 14, items 10 and 12 in Figure 15);

h) vent valve shall open on every shutdown (see item 9 in Figure 14 and Figure 15).

NOTE Figure 14 and Figure 15 show typical arrangements and indicate the operation of the valves. Table 4 defines the symbols for Figure 14 and Figure 15.

7.9.1.2.1.2 Where the gas fuel supply system comprises more than one supply or a single supply is divided for multiple uses, equipment in each supply shall be duplicated such that the individual supplies comply with 7.9.1.2.

• **7.9.1.2.1.3** Safety shut-off valves and vent valves shall be certified by the specified regulatory agency.

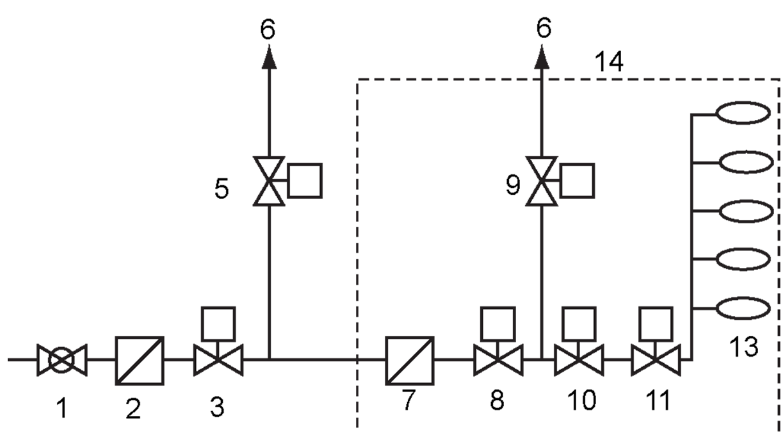


Figure 14—Typical Fuel Gas System—Typical Arrangement A

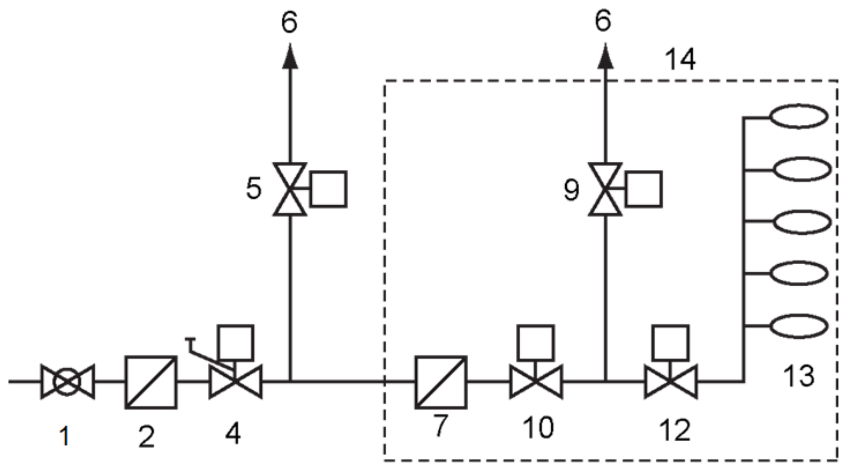


Figure 15—Typical Fuel Gas System—Typical Arrangement B

Table 4—Typical Fuel Gas System Components

Key	Type of Equipment
1	Manual isolation valve
2	Strainer or filter, optional position
3	Shut-off valve
4	Shut-off valve and manual isolation valve
5	Vent valve
6	Vent to safe atmosphere
7	Strainer or filter, optional position
8	Shut-off valve [a]
9	Vent valve [b]
10	Automatic fast-acting shut-off valve [a]
11	Flow control valve
12	Flow control and shut-off valve [a]
13	Combustion system
14	Typical gas turbine enclosure or building limits

[a] Close on every shutdown.
[b] Vent on every shutdown.

• **7.9.1.2.1.4** If specified, a fuel gas compression system shall be supplied.

NOTE A fuel gas compression system is used if the fuel gas pressure required by the gas turbine is higher than that available.

• **7.9.1.2.1.5** If specified, a system for purging the fuel gas line prior to starting shall be supplied.

• **7.9.1.2.1.6** If specified, a fuel gas pressure regulator shall be supplied upstream of the manual isolation valve (see item 1 in Figure 14 and Figure 15).

7.9.1.2.1.7 Leak tight and automatic fast-acting shut-off valves shall fail closed.

7.9.1.2.1.8 Vent valves and associated pipework shall be sized to ensure the depressurized pipe remains at atmospheric pressure taking into account the potential for leakage in upstream valves.

7.9.1.2.1.9 Integral valve combinations (see item 12 in Figure 14) may be used providing the necessary functional safety is achieved without introducing additional risk.

7.9.1.2.2 Isolation

7.9.1.2.2.1 The manual isolation valve (see item 1 in Figure 14 and Figure 15) shall be:

a) identifiable by a distinctive sign with "GAS TURBINE (tag number) FUEL SHUT-OFF VALVE" in 50 mm (2 in.) or larger letters;

b) located in an accessible position;

c) capable of being operated by an acceptable level of physical force without any tools.

NOTE Guidance on the physical strength for the hand-operation of equipment is given in EN 614-1.

7.9.1.2.2.2 This valve shall be capable of being locked closed, but not locked open.

7.9.1.2.3 Flow Control Valve

7.9.1.2.3.1 The fuel flow control valve (see item 11 in Figure 14 and item 12 in Figure 15) shall be designed and positioned to control the fuel flow to the gas turbine under all operating conditions [fuel composition (see 7.9.2 and 7.9.4), environmental conditions (see 6.6), fuel pressure, fuel temperature, and gas turbine load].

7.9.1.2.3.2 The fuel flow control valve shall be sized such that the trim can be replaced to achieve 10 % higher or lower fuel flow.

NOTE The intent is to allow for small gas turbine rating changes or operating point changes without replacing the fuel flow control valve body.

7.9.1.2.3.3 The position of the fuel flow control valve (see item 11 in Figure 14 and item 12 in Figure 15) shall be continuously monitored and if an "out of position to demand" is detected, a shutdown shall be initiated.

7.9.1.2.3.4 The fuel system shall be designed to mitigate risks associated with excess flow.

NOTE Pre- or post-purchase order risk assessment of the fuel system can identify high-risk scenarios (e.g. excess fuel flow due to failure of fuel flow control equipment).

7.9.1.2.4 Shut-off Valves and Associated Vent Valve

7.9.1.2.4.1 Shut-off of the gas fuel supply shall be performed by two independently operated automatic shut-off valves (see Figure 14, and Figure 15—items 8, 10, and 12).

7.9.1.2.4.2 The piping between the two shut-off valves shall be vented (see Figure 14, and Figure 15—item 6).

7.9.1.2.4.3 At least one of the two shut-off valves shall be a leak tight valve.

7.9.1.2.4.4 At least one of the two shut-off valves shall automatically close fast enough to prevent gas turbine overspeed.

7.9.1.2.4.5 The non-fast-acting shut-off valve may serve as the flow control valve (see Figure 15—item 12).

7.9.1.2.4.6 Upon shutdown, both shut-off valves (see Figure 14, and Figure 15—items 8, 10, and 12) shall be closed and the automatic vent valve opened (see Figure 14, and Figure 15—item 9) to create atmospheric pressure in the supply line to eliminate the possibility of fuel entering the gas turbine in its shutdown condition.

7.9.1.2.4.7 Unless otherwise specified, the maximum backpressure on gas vents shall be 50 kPa (7 psi) gauge. All gas vents will be piped to atmosphere.

7.9.1.2.4.8 If adequate dispersion cannot be ensured or where environmental considerations prohibit venting to atmosphere, the gas vents may be piped to a flare stack. The maximum backpressure of the vent shall be mutually agreed by the purchaser and vendor.

7.9.1.2.5 Shut-off Valve—Outside the Gas Turbine Package

• **7.9.1.2.5.1** The shut-off valve (see Figure 14—item 3 and Figure 15—item 4) shall be provided by the vendor or purchaser, as specified.

7.9.1.2.5.2 The shut-off valve shall be located outside the gas turbine enclosure or building limits, or in a separately enclosed gas fuel package at the interface of the enclosure or building, to automatically isolate the fuel supply to the gas turbine in the event of a dangerous situation.

NOTE If the gas turbine package is located in a building, the shut-off valve can be located outside the building to provide additional isolation.

• **7.9.1.2.5.3** If specified, the vendor shall provide the exterior vent valve (see item 5 in Figure 14 and Figure 15).

7.9.1.2.5.4 The associated vent valve shall be located outside the gas turbine or gas fuel package to vent the section of the pipe between the shut-off valve and the automatic fast-acting shut-off valve.

7.9.1.2.5.5 The fuel shut-off and the vent valve(s) shall be operated automatically on a gas turbine trip and shutdown.

7.9.1.2.6 Strainer/Filter

7.9.1.2.6.1 A strainer or filter (see item 7 in Figure 14 and Figure 15) shall be provided upstream of any automatic fast-acting shut-off valve (see item 10 in Figure 14 and Figure 15) to prevent valve malfunction due to debris entering the valve.

• **7.9.1.2.6.2** If specified, dual Y-type strainer(s) with a continuous flow transfer valve shall be supplied and mounted off-base (see item 2 in Figure 14 and Figure 15) and be capable of being cleaned while in operation.

7.9.1.2.6.3 The transfer valve shall, as a minimum, conform to Table 3 and suitable for the fuel gas composition.

7.9.1.2.6.4 The strainer or filter element shall be rated 3   m absolute or less.

7.9.1.2.7 Valve Proving and Position Monitoring

7.9.1.2.7.1 Prior to startup, the automatic fast-acting shut-off valve (see item 10 in Figure 14 and Figure 15), the automatic leak tight shut-off valve (see item 8 in Figure 14 and item 12 in Figure 15), and the automatic vent valve (see item 9 in Figure 14 and Figure 15), shall be cycled and automatically monitored to confirm correct operation of the valves.

7.9.1.2.7.2 At startup, the control system shall automatically confirm correct position of all automatically operated valves.

7.9.1.2.7.3 At shutdown the control system shall automatically alarm if all automatically operated valves are not in the correct positions.

• **7.9.1.2.7.4** If specified, valve proving logic and equipment (e.g., pressure transmitters) shall be installed to facilitate pressurization and pressure monitoring.

7.9.1.3 Fuel Gas Piping and System Requirements

7.9.1.3.1 Gas piping and tubing shall, as a minimum, conform to Table 3. Special materials (e.g. duplex stainless steels) may be required for corrosive fluids (see 7.9.1.1) and environments (see 6.6).

7.9.1.3.2 Use of flexible hoses shall be minimized. Proposal shall describe where flexible hoses are used. See 9.2.3.2 m).

7.9.1.3.3 All fuel hoses shall be 316 or 316L, as a minimum, and covered with abrasion-resistant braiding.

7.9.1.3.4 System design shall incorporate sufficient separation around each flexible hose at all times to prevent fretting damage to the braiding.

7.9.1.3.5 Fuel components, piping, and tubing shall not be routed in the path of potential gas turbine disk burst debris.

7.9.1.3.5.1 Gas piping spools shall be full penetration butt-welded and hydrotested prior to assembly.

7.9.1.3.5.2 Gas piping shall be pneumatically leak tested after assembly (see 8.3.3).

NOTE The final connection to the gas generator cannot be normally leak tested until the unit starts operation at site.

7.9.1.3.5.3 Where it is not practical to conduct a final assembly pneumatic or hydrostatic pressure test on the piping connected to the combustion system, a safe commissioning procedure shall be adopted to check for leaks on the running gas turbine. The procedure adopted shall be shown to achieve a tolerable level of risk and shall be appropriately documented.

7.9.2 Gaseous Fuel

7.9.2.1 Composition

7.9.2.1.1 The gas turbine package shall be designed for the specified fuel compositions.

7.9.2.1.2 Proposal shall define the fuel-specific flow rates, minimum fuel temperatures and pressures required at fuel supply boundary point (e.g. fuel skid inlet). See 9.2.3.2 m).

NOTE Gas fuels are typically superheated at the supply boundary point to be above hydrocarbon and water dew points at the gas turbine fuel injectors to prevent over temperature damage to the turbine due to burning condensate.

7.9.2.1.3 Proposal shall provide detailed fuel specifications (including dew point margins or superheat) and condition ranges required for safe and reliable operation. See 9.2.3.2 m).

7.9.2.1.4 Unless otherwise specified, gas fuel treating to meet the specified (see 7.9.2.1) requirements will be provided by the purchaser.

7.9.2.2 Contaminants

7.9.2.2.1 To alleviate a possibility of liquid contamination, the vendor shall review both the design and off-design operation of the fuel supply system, including both the vendor's and the purchaser's fuel supply systems.

• **7.9.2.2.2** If specified, a coalescing filter shall be supplied and sized to keep liquid contents in the fuel gas at or below the maximum levels allowed by the gas turbine manufacturer.

NOTE The coalescing filter is used to reduce the potential for damage to the hot-gas-path components from entrained liquids.

7.9.2.3 Corrosive Agents

7.9.2.3.1 The gas turbine and fuel system shall be suitable for the concentration of hydrogen sulfide, sulfur dioxide, sulfur trioxide, total sulfur, alkali metals, chlorides, carbon monoxide, and carbon dioxide (see 7.9.2 and 7.9.4).

NOTE Sulfur can cause elevated-temperature corrosion of turbine hot-gas-path components and ambient-temperature corrosion of fuel control valves and systems (see Annex E). Total sulfur content can cause corrosion in heat-recovery equipment (see 7.7.3.1.3).

7.9.2.3.2 Means shall be provided to prevent the emission of hazardous or toxic substances from the machine in accordance with ISO 14123-1. If these means cannot remove the hazard completely or reduce its effects to a nonhazardous level, then additional precautions such as those below shall be taken:

a) increase height of vent to ensure adequate dispersion;

b) locate vent in an area that is not normally accessible to personnel;

c) monitor and alarm systems to be installed for hazardous atmosphere together with evacuation and shutdown processes.

7.9.2.4 Heating Value

7.9.2.4.1 The gas turbine shall be capable of operation, without manual intervention, on fuel gases within plus or minus 10 % of the lower heating value (LHV) of the fuel gases in 7.9.1.

• **7.9.2.4.2** The gas turbine shall be capable of operation for the specified rate of change of the WI or the modified Wobbe index (MWI) (see E.6.3) for the fuel gases in 7.9.1.

• **7.9.2.4.3** If specified, all special equipment (e.g. gas chromatograph, calorimeter, Wobbe meter), necessary to attain the WI or the MWI rate of change shall be provided (see 7.9.2.4.2).

7.9.2.4.4 Proposal shall describe the capabilities of the proposed combustion system for the rate of change of the WI or the MWI (see 7.9.2.4.2). See 9.2.3.2 m).

7.9.2.5 Fuel Supply Heating

7.9.2.5.1 When fuel heaters are supplied, protection from overheating the fuel and protection from cross contamination between the fuel and the heat transfer fluid media shall be provided.

7.9.2.5.2 Flame fired direct heating shall not be used.

7.9.2.5.3 When fuel supply heat tracing is provided, the design shall self-limit the temperature or control thermostats shall be used.

• **7.9.2.5.4** If specified, gas fuel heater shall be provided.

7.9.3 Liquid Fuel System

7.9.3.1 Fuel Control

7.9.3.1.1 As a minimum each liquid fuel supply shall include the following functions (see Figure 16):

a) manual isolation (see 7.9.3.2);

b) flow control (see 7.9.3.3);

c) automatic fast-acting shut-off (see 7.9.3.4);

d) leak tight shut-off (see 7.9.3.5);

e) spill and/or drain (see 7.9.3.4 and 7.9.3.6);

f) fuel pump.

7.9.3.1.2 Automatic fuel shut-off rate shall prevent dangerous failure of the gas turbine and the possibility of fuel entering the gas turbine in its shutdown condition.

7.9.3.1.3 Leak tight and automatic fast-acting shut-off valves shall fail closed.

7.9.3.2 Isolation

The manual isolation valve (see item 1 in Figure 16) shall be:

a) identifiable by a distinctive sign with “GAS TURBINE (tag number) FUEL SHUT-OFF VALVE” in 50 mm (2 in.) or larger letters;

b) located in an accessible position;

c) capable of being operated by an acceptable level of physical force without any tools;

d) this valve shall be capable of being locked closed, but not open.

NOTE Guidance on the physical strength for the hand-operation of equipment is given in EN 614-1.

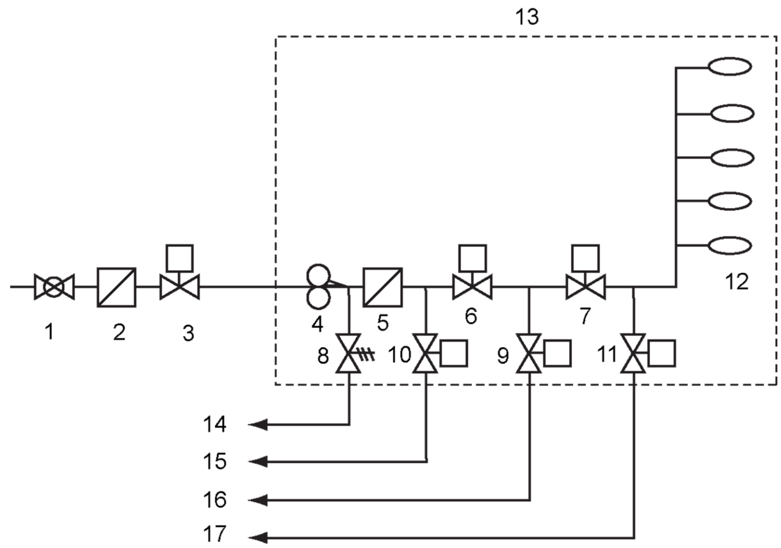
7.9.3.3 Flow Control Device

7.9.3.3.1 The fuel flow control device (see item 6 in Figure 16) shall be designed and positioned to control the fuel flow to the gas turbine under all operating conditions [operating conditions (see 6.6), fuel composition (see 7.9.2 or 7.9.4), fuel pressure, fuel temperature, and gas turbine load].

7.9.3.3.2 The fuel system shall be designed to mitigate risks associated with excess flow.

NOTE Pre- or post-purchase order risk assessment of the fuel system can identify high risk scenarios (e.g. excess fuel flow due to failure of fuel flow control equipment).

7.9.3.3.3 The position of the fuel control valve (see item 6 in Figure 16) shall be monitored and if an “out of position to demand” is detected, a shutdown shall be initiated. Other systems may use different control methods.



NOTE See Table 5 for the definition of the symbols.

Figure 16—Liquid Fuel System—Typical Arrangement

Table 5—Typical Liquid Fuel System Components

Key	Type of Equipment
1	Manual isolation valve
2	Filter or strainer, optional position
3	Shut-off valve
4	Fuel pump, may be located outside gas turbine enclosure
5	Filter or strainer, optional position
6	Flow control device
7	Automatic fast-acting shut-off valve
8	Relief valve
9	Spill valve
10	Spill valve—alternative location
11	Drain valve
12	Combustion system
13	Typical gas turbine enclosure or building limits
14	Relief
15	Return to supply—alternate location with 10
16	Return to supply
17	Drain

7.9.3.4 Automatic Fast-acting Shut-off Valve and Spill Valve

7.9.3.4.1 Shut-off of the liquid fuel supply shall be performed by two independently operated automatic shut-off devices (see items 3 and 7 in Figure 16).

7.9.3.4.2 At least one valve shall be an automatic fast-acting shut-off valve (see item 7 in Figure 16).

7.9.3.4.3 After operation of the shut-off devices and after any fuel purging, a valve (see item 17 in Figure 16) shall drain a section of the supply line to eliminate the possibility of fuel entering the gas turbine in its shutdown condition.

7.9.3.4.4 This valve shall be sized to ensure the drained pipe volume remains near atmospheric pressure taking into account the potential for leakage in upstream valves.

7.9.3.4.5 Where a spill valve does not spill to atmospheric pressure, a drain valve shall be supplied in accordance with 7.9.3.6.

NOTE Site operations personnel can prefer that the liquid fuel system to remain pressurized when liquid fuel is not being furnished to the gas turbine in order to minimize either starting time or fuel transfer.

7.9.3.4.6 Where spill flow is returned to the pump suction, sufficient cooling and/or make up flow shall exist to prevent overheating and the potential for vapor lock; otherwise, the fuel supply temperature before the pump suction shall be monitored and a shutdown initiated if overheating occurs.

7.9.3.4.7 The automatic fast-acting shut-off valve (see item 7 in Figure 16) shall close on every shutdown and trip.

7.9.3.5 Shut-off Valve—Outside the Gas Turbine Package

7.9.3.5.1 Shut-off valve (see item 3 in Figure 16) shall be automatic and located outside the gas turbine package or building limits, or in a separately enclosed liquid fuel package at the interface of the enclosure or building, to automatically isolate the fuel supply to the gas turbine in the event of a dangerous situation.

NOTE Where the gas turbine package is located in a building, the shut-off valve can be located outside the building to provide additional isolation.

• **7.9.3.5.2** If specified, the vendor shall provide the shut-off valve.

7.9.3.5.3 The automatic shut-off valve shall be operated automatically on a gas turbine trip and shutdown.

7.9.3.6 Drain Valve

7.9.3.6.1 Where the spill valve (see items 9 and 10 in Figure 16) does not spill to atmospheric pressure, an automatic drain valve (see item 11 in Figure 16) shall be installed to drain fuel downstream of the automatic fast-acting shut-off valve, which shall operate on every trip and shutdown to drain liquid.

7.9.3.6.2 The drain sequence shall be controlled to prevent ignition of any hydrocarbons in the drain or purge lines due to reverse flow of gas turbine compressor air.

7.9.3.6.3 If there is the potential for reverse flow, cooling, flame arresters or separators shall be used to prevent any ignition escalating outside the gas turbine package.

7.9.3.6.4 If there is the potential for reverse flow from the tank, appropriate devices and instrumentation shall be installed so that protection is provided against reverse flow into the gas turbine under all conditions identified by hazard analyses.

7.9.3.6.5 The drain valve (see item 11 in Figure 16) shall be automatically controlled on every shutdown.

7.9.3.7 Filter/Strainer

7.9.3.7.1 A filter/strainer (see item 5 in Figure 16) shall be installed downstream of the fuel pump (see item 4 in Figure 16) and upstream of the fuel flow control device (see item 6 in Figure 16) and automatic fast-acting shut-off valve (see item 7 in Figure 16) at a suitable location to prevent device or valve malfunction due to debris entering the device or valve.

• **7.9.3.7.2** If specified, a second filter/strainer (see item 2 in Figure 16) shall be installed or provided and shipped loose.

7.9.3.7.3 If the primary fuel is liquid, duplex fuel filters (see items 2 and 5 in Figure 16) shall be used with continuous flow transfer valves to allow online filter replacement.

7.9.3.7.4 Transfer valves shall, as a minimum, conform to Table 3.

7.9.3.8 Valve Proving and Position Monitoring

7.9.3.8.1 Prior to each startup, the automatic fast-acting shut-off valve (see item 7 in Figure 16), shut-off valve (see item 3 in Figure 16), and the spill valve (see item 9 or 10 in Figure 16) shall be cycled and automatically monitored to confirm correct operation of the valves.

7.9.3.8.2 During each startup, the control system shall automatically confirm correct position of all automatically operated valves.

7.9.3.8.3 During each shutdown, the automatic fast-acting shut-off valve (see item 7 in Figure 16), shut-off valve (see item 3 in Figure 16), and the drain valve (see item 11 in Figure 16) shall be monitored to ensure that correct operation of the valves has been achieved.

7.9.3.8.4 At shutdown, the control system shall automatically alarm if all automatically operated valves are not in the correct positions.

7.9.3.9 Thermal relief shall be provided when the potential exists for liquid to be trapped between closed leak tight valves.

7.9.3.10 Multi-fuel Systems

7.9.3.10.1 Fuel systems shall prevent reverse flow from one fuel system to another.

NOTE Ensure that liquid fuels cannot enter the gas fuel system where gas fuel is used to purge the liquid fuel burners.

7.9.3.10.2 Where only a single fuel can be fired at any one time, interlocks shall prevent other fuel systems from inadvertently operating or leaking. Interlocks shall not prevent online fuel changeover.

7.9.3.10.3 Where more than one fuel can be fired at any one time, the fuel system shall prevent excessive fuel input.

7.9.3.10.4 When operating on gas fuel, the liquid fuel lines, fuel injector, manifolds, etc., shall be automatically purged, continuously to prevent plugging and coking.

7.9.3.11 Where forward and reverse purge/drain sequences are used (e.g. during startup, operation, or shutdown), a risk assessment shall be performed including the following, as a minimum:

a) failure of reverse purge sequence during shutdown leaving low auto-ignition temperature fuels in the feed lines with the potential for uncontrolled ignition on a restart;

b) inadequate draining of liquid fuel after a failed start leaving liquid fuel in the drain lines with the potential for uncontrolled ignition on restart;

c) the potential for ignition of vapors in the purge drain lines/vent tank(s) due to the temperature of reverse purge combustion air;

d) contamination of liquid fuel storage with low auto-ignition fuel should a purge/drain sequence fail with the potential for uncontrolled ignition on restart due to contamination of the fuel used for starting;

e) the potential for vapor lock (change of state resulting in increased volume and pressure);

f) uncontrolled supply, venting or draining of fuel or air-fuel mixture;

g) the presence of condensates at low points.

NOTE Appropriate instrumentation, double block and vent valves, valve position monitoring, prevention of reverse flow, separation of media, flame arresters, etc., are typically used to mitigate risks.

7.9.3.12 Fuel Drains

7.9.3.12.1 Where liquid fuel is used, suitable drain points shall be incorporated to drain off fuel from the pressure section of the casing and exhaust system (e.g. in the event of a flame failure on startup).

7.9.3.12.2 All drain points shall have automatically operated valves that open on shutdown and close as part of the start sequence.

7.9.3.12.3 Prior to initiating a restart, the start sequence shall provide a sufficient time for automatic fuel drain valves to drain liquid fuel.

7.9.3.12.4 A risk assessment shall be performed including the following, as a minimum:

a) fuel drain valve sequencing logic;

b) fuel drain valve failsafe position;

c) effectiveness of the drain system;

d) monitoring fuel drain valve position;

e) prestart purge;

f) overspeed caused by burning undrained liquid fuel during startup;

g) hot gas entering the drain system during operation;

h) fuel-air mixtures entering the drain system.

7.9.3.13 Fuel Supply Heating

7.9.3.13.1 Proposal shall describe if liquid fuel heating is required. See 9.2.3.2 m).

NOTE Heaters can vaporize, superheat, or reduce viscosity of the fuel to within the manufacturer's limits.

7.9.3.13.2 If required, the purchaser will provide liquid fuel heater in accordance with 7.9.2.5.

• **7.9.3.14** If specified, fuel transfer equipment shall be supplied.

7.9.4 Liquid Fuel

• **7.9.4.1** The gas turbine package shall be designed for the specified a) grade of liquid fuel in accordance with ASTM D2880, ASTM D1655 or b) furnish a complete analysis for other liquid fuels.

7.9.4.2 Proposal shall identify if the startup fuel can auto ignite from hot internal surfaces. See 9.2.3.2 m).

NOTE This auto-ignition can lead to dangerous overpressure conditions or uncontained component failure. (This would typically apply to fuels such as naphtha where significant potential exists for the formation of large potentially explosive vapor clouds.)

7.9.4.3 In some cases, mutual agreement on permissible contaminant levels in the fuels to be burned in the gas turbine is required between the interested parties. For those cases, in which no mutual agreement is reached, the contaminant levels defined as permissible by the gas turbine manufacturer's fuel specification shall apply. See ASTM D2880 for additional details.

NOTE 1 Fuel classifications for gas turbines are listed in ASTM D2880 and ASTM D1655. ASTM D2880 divides fuel oils into five grades based on their applicability for use in gas turbines. It does not include fuels primarily intended for jet aircraft use. ASTM D1655 covers fuels primarily intended for use in jet aircraft.

NOTE 2 Both ASTM D2880 and ASTM D1655 place limiting values on a number of the properties of the oils in each grade. The properties selected for limitation are those believed to be of the greatest significance in determining performance characteristics of the oils in various gas turbine applications. Other property considerations include the following.

NOTE 3 Gas turbine operation and maintenance requirements are benefited if fuels have thermal stability, good combustion quality, and low sulfur and ash content. These qualities become increasingly important when the temperatures of the fuel system and operating turbine are high or when long periods between overhaul are desired.

NOTE 4 ASTM D2880 Grade 0-GT includes naphtha, Jet B, and other light hydrocarbon liquids that characteristically have low flash points and low viscosities compared to those of kerosene and fuel oils. ASTM D2880 Grade 1-GT is a light distillate fuel suitable for use in nearly all gas turbines. ASTM D2880 Grade 2-GT is a distillate that is heavier than Grade 1-GT, and it can be used by gas turbines not requiring the clean burning characteristics of Grade 1-GT. Fuel heating equipment can be necessary, depending on the fuel system design or the ambient temperature conditions or both. ASTM D2880 Grade 3-GT can be a distillate that is heavier than Grade 2-GT, a residual fuel oil that meets the low ash requirement, or a blend of a distillate and a residual fuel oil. If Grade 3-GT is specified, the gas turbine will require fuel heating in almost every installation. ASTM D2880 Grade 4-GT includes most residuals and some topped crude oils. Because of the wide variation and lack of control of properties, the gas turbine manufacturer is be consulted about acceptable limits on properties. ASTM D1655 Jet A and Jet A-1 are relatively high flash point distillates of the kerosene type. They represent two grades of kerosene fuel that differ only in freezing point. ASTM D1655 Jet B is a relatively wide boiling range volatile distillate.

7.9.4.4 Unless otherwise specified, liquid fuel treating to meet the specified (see 7.9.4.1) requirements will be provided by the purchaser.

7.9.5 Multi-fuel Operation

7.9.5.1 Unless otherwise specified, the gas turbine shall be provided with the necessary equipment to permit normal operation (starting and continuous) with each fuel source.

7.9.5.2 The fuel system shall provide the capability of automatic transfer between fuel sources while under full or part load operation.

• a) The automatic fuel transfer time shall not be greater than the specified maximum fuel transfer time.

b) Minimum fuel transfer time of the proposed system shall be listed on the datasheet.

7.9.5.3 Operator initiation of automatic transfer shall be through a dry contact type switch.

7.9.5.4 The fuel system shall provide smooth fuel source transfer without shutdown or interruption of load-carrying ability.

7.9.5.5 Proposal shall clarify how the maintenance program (e.g. hot gas path, fuel systems) is affected by fuel composition (see 7.9.2 or 7.9.4). See 9.2.3.2 m).

7.9.6 Emission Suppression Systems

• **7.9.6.1** The gas turbine package, including all auxiliaries, shall meet the specified air emissions (e.g. NO_X, CO, UHC, sulfur oxides, particulates) levels for the expected power output range and fuels (see 7.9.2 and 7.9.4). See 6.2.1.

NOTE See Annex E for more information on air emissions.

7.9.6.2 Unless otherwise specified and if an emissions suppression system is necessary, the emission suppression system shall be a DLE type.

7.9.6.2.1 For wet low emissions (WLE) type, the proposal shall describe the water or steam specifications. See 9.2.3.2 m).

7.9.6.2.2 For WLE type, the proposal shall describe gas turbine package performance with and without the WLE system active. See 9.2.3.2 m).

• **7.9.6.3** If specified, a selective catalyst reduction (SCR) may be used as an emissions suppression system.

7.9.6.4 Proposal [see 9.2.3.2 m)] shall fully describe the air emission suppression system, including the following:

a) air emission variations with all fuels;

b) effect of ambient temperature range on emissions;

c) effect of anti-icing system on emissions, if supplied;

d) associated engine power and engine heat rate;

e) effect on exhaust temperature and flow rate.

• **7.9.6.5** If specified or with the purchaser's approval, the instantaneous level of emissions suppression may be allowed to vary as long as the annual emissions output (e.g. tons/year) is not exceeded.

NOTE By allowing this variance, the complexity of some dry emission suppression systems can be reduced.

7.9.7 Ignition Systems

7.9.7.1 The ignition system shall include an ignition transformer and igniter plugs.

7.9.7.2 Ignition shall be automatically de-energized and fuel flow shall be stopped if the gas turbine fails to fire after a given period.

7.10 Access Routes

7.10.1 All platforms, walkways, handrails, guardrails, stairways, and ladders shall be in accordance with OSHA 29 *CFR* 1910 and 1926.

7.10.2 Design and construction of exit routes shall be in accordance with OSHA 29 *CFR* 1910.36.

7.11 Special Tools

7.11.1 If special tools are required to disassemble, assemble or maintain the unit, the proposal shall include one complete set as an individual line item. See 9.2.3.2 m).

NOTE For multiple gas turbine installations, the quantity of special tools can be adjusted to suit owner's needs.

7.11.2 All special tools, if provided, shall be packaged in dedicated, rugged metal box(es) labelled "special tools for (tag/item number)."

7.11.3 Each special tool shall be stamped or metal tagged to indicate its intended use.

8 Inspection, Testing, and Preparation for Shipment

8.1 General

• **8.1.1** Vendor shall accommodate the purchaser's participation (e.g. witness, observe) in the inspection and testing as specified.

8.1.2 Expected testing dates shall be communicated at least 30 days in advance.

8.1.3 Unless otherwise specified, inspection or testing dates shall be communicated at least 10 days before conducting any inspection or test that the purchaser has specified to be witnessed or observed.

8.1.4 Inspection or testing dates shall be confirmed at least 5 days before conducting any inspection or test to be witnessed or observed by the purchaser (see 8.1.1).

8.1.5 If the testing is rescheduled, the vendor shall immediately notify the purchaser and a new date shall be agreed upon with 5 working days advanced notification.

NOTE Due to the complex testing requirements, the purchaser's representative can be present during setup.

• **8.1.6** If specified, the purchaser's representative, the vendor's representative, or both shall indicate compliance in accordance with the inspector's checklist by initialing, dating, and submitting the completed checklist to the purchaser before shipment.

8.1.7 After advance notification to the vendor, the purchaser's representative shall have entry to all vendor and subvendor plants where manufacturing, testing, or inspection of the equipment is in progress.

NOTE It is not possible to see everything. The purchaser does not normally visit or inspect manufacturing facilities of commodity items (e.g. small valves, tubing, transmitters, etc.).

8.1.8 The subvendors shall accommodate the purchaser's participation in the inspection and testing (see 8.1.1), including the advance notification required.

8.1.8.1 For shop inspection and testing (see 8.1.1), the purchaser and the vendor shall coordinate manufacturing hold points and inspectors' visits.

• **8.1.8.2** If specified, successful preliminary tests shall be completed prior to witnessed mechanical run and witnessed performance tests.

8.1.9 Equipment, materials, and utilities for the inspections and tests (see 8.1.1) shall be provided by the vendor.

8.1.10 The purchaser's representative shall have access to the vendor's quality program for review.

8.2 Inspection

8.2.1 General

8.2.1.1 Vendor shall keep the following data available for at least 20 years:

• a) necessary or specified certification of materials, such as mill test reports (e.g. ISO 10474, type 3.1 and 3.2); pressure-containing parts shall be supplied with Inspection Certificates conforming to ISO 10474, type 3.1; other parts shall be delivered with certificates of compliance conforming to ISO 10474, type 2.1;

b) test data and results to verify that the requirements of the specification have been met;

c) fully identified records of all heat treatment whether performed in the normal course of manufacture or as part of a repair procedure;

d) results of quality control tests and inspections;

e) details of all repairs;

f) final assembly maintenance and running clearances;

• g) other data specified by the purchaser or required by applicable codes and regulations.

8.2.1.2 Pressure-containing parts shall not be painted until the inspection and testing (see 8.1.1) of the parts is complete.

• **8.2.1.3** In addition to the requirements of 6.24.1 and the ASTM material specification, the specified parts shall be examined (e.g. magnetic particle, liquid penetrant, radiographic, and ultrasonic).

NOTE ASTM material specifications contain mandated and supplemental inspections.

8.2.2 Material Examination

8.2.2.1 General

8.2.2.1.1 All radiographic, ultrasonic, magnetic particle, or liquid penetrant inspection of welds or materials shall conform to 8.2.2.2 through 8.2.2.5.

8.2.2.1.2 Equivalent international standards may be applied for 8.2.2.2 through 8.2.2.5 after purchaser approval. See 6.20.21.

8.2.2.1.3 Cast iron shall be inspected only in accordance with 8.2.2.4 and/or 8.2.2.5.

8.2.2.1.4 Welds, cast steel, and wrought material shall be inspected in accordance with 8.2.2.2 through 8.2.2.5.

NOTE Since the specification (for the actual component being inspected) depends on metallurgy, component configuration, and method of manufacture; specific procedures and acceptance standards for the application need to be covered by written standards, developed by the manufacturer for the specific application.

8.2.2.1.5 Acceptance standards for 8.2.2.2 through 8.2.2.5 shall be mutually agreed upon between the purchaser and vendor.

NOTE Acceptance criteria can be found in API 687 Chapter 1, Appendix K, Quality/Manufacturing Plan.

8.2.2.2 Radiography

Radiography shall be in accordance with ASTM E94 (welds); ASME *BPVC* Section VIII, Division 1, Appendix 7 (castings); and ASME *BPVC* Section VIII, Division 1 UW-52 (welds).

8.2.2.3 Ultrasonic Inspection

Ultrasonic inspection shall be based upon the procedures of ASTM A609/A609M (castings); ASTM A388/A388M (forging); or ASTM A578 (plate); ASME *BPVC* Section VIII, Division 1, Appendix 7 for castings; and ASME *BPVC* Section VIII, Division 1, Appendix 12 for welds.

8.2.2.4 Magnetic Particle Inspection

8.2.2.4.1 Both wet and dry methods of magnetic particle inspection shall be in accordance with ASTM E709 (castings); ASME *BPVC* Section VIII, Division 1, Appendix 7 (castings); and ASME *BPVC* Section VIII, Division 1, Appendix 12 (welds).

8.2.2.4.2 To prevent buildup of potential voltage in the equipment, all components shall be demagnetized to the free air gauss levels in Table 6 when measured with a calibrated Hall effect probe.

Table 6—Maximum Allowable Free Air Gauss Levels

±2 Gauss	Bearing and seal assemblies including all components
±4 Gauss	Casing and all stationary components except bearing and seal assemblies
±2 Gauss	Shaft and all rotating components

NOTE The free air gauss level is measured while suspending the component from a nonconductive strap with no influence from stray magnetic fields.

8.2.2.5 Liquid Penetrant Inspection

Liquid penetrant inspection shall be based upon the procedures of ASTM E165/E165M and ASTM E1417/E1417M; ASME *BPVC* Section VIII, Division 1, Appendix 7 for castings; and ASME *BPVC* Section VIII, Division 1, Appendix 8 for welds.

8.2.3 Mechanical Inspection

8.2.3.1 During assembly of the equipment, each component (including integrally cast-in passages) and all piping and appurtenances shall be inspected to ensure that they have been cleaned and are free of foreign materials, corrosion productions, and mill scale.

8.2.3.2 All oil systems furnished shall meet the cleanliness requirements of API 614.

• **8.2.3.3** If specified, the equipment and all piping and appurtenances shall be inspected for cleanliness before heads are welded onto vessels, openings in vessels or exchangers are closed, or piping is finally assembled.

• **8.2.3.4** If specified, the hardness of parts, welds, and heat-affected zones shall be verified as being within the allowable values by testing. The method, extent, documentation, and witnessing of the testing shall be mutually agreed upon by the purchaser and the vendor.

8.3 Testing

8.3.1 General

8.3.1.1 Equipment shall be tested in accordance with 8.3.2 through 8.3.4. Other tests that may be required are described in 8.3.5.

8.3.1.2 At least 6 weeks before any test in 8.3, the vendor shall submit to the purchaser, for review and comment, detailed procedures including acceptance criteria for all monitored parameters.

NOTE Testing notification requirements are in 8.1.

8.3.2 Hydrostatic Test

8.3.2.1 Proposal shall identify components to be tested hydrostatically. See 9.2.3.2 m).

NOTE Gas turbine package components are hydrostatically tested at the component level.

8.3.2.2 The hydrostatic tests shall use clean water with a suitable wetting agent.

8.3.2.3 Pressure-containing parts (as identified in 8.3.2.1), including auxiliaries, shall be tested hydrostatically with liquid at a minimum of 1.5 times the maximum allowable working pressure (MAWP).

8.3.2.4 The minimum hydrotest pressure shall not be less than 150 kPa (20 psi) gauge.

8.3.2.5 The test liquid shall be at a higher temperature than the nil-ductility transition temperature of the material being tested. Reference ASTM E1003.

NOTE The nil-ductility temperature is the highest temperature at which a material experiences complete brittle fracture without appreciable plastic deformation.

8.3.2.6 The chloride content of liquids used to test austenitic stainless steel materials shall not exceed 50 ppmw.

NOTE 1 Chloride content and its concentration is limited in order to prevent chloride stress corrosion cracking.

NOTE 2 The stress corrosion cracking resistance of 304 and 316 at temperatures below 50 °C show that cracking can be avoided at much higher concentrations than allowed above. The above limit is set based on use of potable water and the requirement to wipe dry, which prevents much higher concentrations of chlorides from forming.

8.3.2.7 To prevent deposition of chlorides on austenitic stainless steel as a result of evaporative drying, all residual liquid shall be removed from tested parts at the conclusion of the test.

8.3.2.8 If the part tested is to operate at a temperature at which the strength of a material is below the strength of that material at the testing temperature, the hydrostatic test pressure shall be multiplied by a factor obtained by dividing the allowable working stress for the material at the testing temperature by that at the rated operating temperature.

NOTE The strength of many grades of steel does not change appreciably at temperatures up to 200 °C (400 °F).

8.3.2.8.1 The stress values used shall conform to those given in ASME B31.3 for piping or in Section VIII, Division 1 of the ASME *BPVC*.

8.3.2.8.2 The pressure thus obtained shall then be the minimum pressure at which the hydrostatic test shall be performed.

8.3.2.8.3 The final datasheets shall list actual hydrostatic test pressures.

8.3.2.9 Where applicable, tests shall be in accordance with the code or standard to which the part has been designed. In the event that a discrepancy exists between the code test pressure and the test pressure in this standard, the higher pressure shall govern.

8.3.2.10 Test duration shall be sufficient to permit complete examination of parts under pressure.

8.3.2.10.1 Hydrostatic tests shall be considered satisfactory when neither leaks nor seepage through the pressure-containing parts or joints are observed for a minimum of 30 minutes.

8.3.2.10.2 Large, heavy, pressure-containing parts or complex systems may require a longer testing period to be agreed upon by the purchaser and the vendor.

8.3.2.10.3 Seepage past internal closures required for testing of segmented cases and operation of a test pump to maintain pressure are acceptable.

8.3.2.11 Gaskets used during hydrotest of an assembled casing shall be of the same design as supplied with the casing.

8.3.3 Pneumatic Testing

• **8.3.3.1** If specified, in addition to hydrostatic testing of pipe systems the manufacturer shall also perform, complete or partial system, pneumatic tests of the gas fuel system using air or other gases at the system design pressure.

8.3.3.2 This test shall be performed after completion of the hydrostatic test (see 8.3.2).

8.3.4 Mechanical Running Test

8.3.4.1 The mechanical run test shall be performed in accordance with the following requirements.

8.3.4.1.1 The contract shaft seals and bearings shall be used in the machine for the mechanical running test.

8.3.4.1.2 All oil pressures, viscosities, and temperatures shall be within the range of operating values recommended in the gas turbine manufacturer's operating instructions for the specific unit being tested.

8.3.4.1.3 During the test, the gas turbine shall run for 60 minutes at the maximum allowable lube oil temperature.

8.3.4.1.4 For pressure lubricating systems, oil flow rates for each bearing housing through the entire operational speed range of gas turbine train shall be measured.

8.3.4.1.5 If synthetic oil will be used in operation, shop testing shall use synthetic oil with same properties (e.g. type, viscosity grade) and shall be compatible with the oil that will be used in operation.

NOTE Some gas turbines use two different types of lube oil.

8.3.4.1.6 Substitution of different test oil shall be approved by the purchaser.

NOTE If the site has either an exceptionally high or low ambient temperature, it can be beneficial to use a different viscosity oil for testing.

8.3.4.1.7 All joints and connections shall be checked for tightness and any leaks shall be corrected.

8.3.4.1.8 All warning, protective, and control devices used during the test shall be checked and adjusted as required.

8.3.4.1.9 Testing should be with the contract coupling(s). If this is not possible, the test coupling weight, with or without moment simulator (in accordance with API 671), shall not differ from the contract coupling by more than ±10 %.

• **8.3.4.1.10** If specified, auxiliary systems mounted on the gas turbine main base shall be tested with the gas turbine during the mechanical run. These auxiliary systems may include but are not limited to the job oil system(s), fuel systems, starting and cooldown drive systems, atomizing liquid fuel system, and auxiliary gear box.

8.3.4.1.11 Auxiliary systems mounted on a separate auxiliary base (other than the main base) may be tested separately.

8.3.4.1.12 All auxiliary systems, including the control panel, shall be shop tested to confirm satisfactory field operation. Details of the auxiliary system tests shall be developed jointly by the purchaser and the vendor.

NOTE The inlet system, anti-icing systems, exhaust system, sound enclosure, and fire protection system are generally not tested during the mechanical run. They can be included in the complete unit test (see 8.3.5.2).

8.3.4.1.13 Test stand oil filtration shall not be coarser than the job oil filtration system.

8.3.4.1.14 Oil system components downstream of the filters shall meet the cleanliness requirements of API 614 before any test is started.

8.3.4.1.15 All purchased vibration probes, cables, oscillator-demodulators, and accelerometers shall be in use during the test.

a) If vibration probes are not furnished by the vendor or if the purchased probes are not compatible with shop readout facilities, then shop probes and readouts that meet the accuracy requirements of API 670 shall be used.

b) During the test, Bode, polar, Fast Fourier Transform, and cascade plots shall be made representing the behavior during start and shutdown transients and under steady conditions.

c) The frequency range of the plots shall include antifriction bearings and vane/blade excitation ranges.

8.3.4.1.16 Shop test facilities shall include instrumentation with the capability of continuously monitoring and plotting revolutions per minute, peak-to-peak displacement and phase angle (x-y-y'), vibration spectra, Bode plots, and shaft orbits.

8.3.4.1.17 The vibration characteristics determined by the use of the instrumentation in 8.3.4.1.15 and 8.3.4.1.16 shall serve as the basis for acceptance or rejection of the machine (see 6.16.6.2).

8.3.4.1.18 If the vendor installs vibration probes, in addition to that required by 8.3.4.1.16 for the test, the vibration data (minimum and maximum values) shall be recorded and the probe angle and shaft location shall be documented.

8.3.4.2 Unless otherwise specified, the mechanical running test of the equipment shall be conducted as follows.

8.3.4.2.1 The equipment shall run at idle conditions until the bearing and lube oil temperatures have reached the operating range and the shaft vibrations have stabilized.

8.3.4.2.2 The gas turbine shall then be accelerated to minimum governor speed and operated at increments from N_{ma} to N_{mc}. The gas turbine shall stabilize (e.g. lube oil temperature, lube oil pressure, exhaust temperature, vibration) at each speed increment.

NOTE Operating machinery at or near critical speeds can cause operational issues.

8.3.4.2.3 The following requirements shall be checked during the gas turbine mechanical running test:

a) normal engine start including hot and cold;

b) full range operation of variable inlet guide vanes and stator stages;

c) operation of bleed valves;

d) operation of air compressor extraction systems;

e) oil pressures, viscosities, and temperatures at operating values recommended in manufacturer operating instructions for specific unit under test; lubricant consumption can be determined; chip detectors and filters can be examined at completion of testing;

f) oil temperatures and pressure can be varied within the operating limits during the test;

g) casings, lubrication oil system, fuel system, and hydraulic system checked for joint and connection tightness; oil and fuel leaks can be corrected;

h) all job warning, protective, and control devices in use during testing shall be checked and adjusted as required.

8.3.4.2.4 Electronically controlled overspeed trip devices, may be tested at a decreased trip set point or using a simulated speed signal.

8.3.4.2.5 Overspeed trip devices shall respond within 1 % tolerance band of the trip setting.

8.3.4.2.6 The speed governor and any other speed regulating devices shall be tested for smooth performance from N_{ma} to N_{mc}, including no-load stability and response to the control signal.

8.3.4.2.7 The speed shall be reduced to the N_{mc}, and the equipment shall be run continuously for 4 hours.

8.3.4.2.8 If replacement or modification of bearings or seals or dismantling of the case to replace or modify other parts or assembly is required to correct mechanical or performance deficiencies, the initial test will not be acceptable and the final shop tests shall be run after these deficiencies are corrected.

8.3.4.2.9 Unless otherwise specified, spare rotors shall receive the same mechanical running test as the main rotor.

NOTE Sometimes spare rotors are manufactured much later than the main rotor and it is not practical to test both at the same time.

• **8.3.4.2.10** If specified, the following main contract auxiliary systems shall be used during the mechanical running test:

a) control panel;

b) auxiliary gear;

c) starting equipment;

d) lube oil system;

e) hydraulic oil system;

f) gas fuel system;

g) liquid fuel system;

h) atomizing air system;

i) inlet system;

j) exhaust system;

k) enclosure with the associated equipment;

l) fire protection;

m) anti-icing.

NOTE Using the contract auxiliaries can minimize the commissioning and startup time at site. Test procedures will need to be jointly developed.

8.3.4.2.11 After the successful completion of the running tests, a borescopic inspection shall be carried out and found to be within the gas turbine manufacturer's new equipment criteria.

8.3.4.3 The mechanical run test acceptance criteria shall be as follows.

8.3.4.3.1 During the mechanical running test, the mechanical operation of all equipment being tested and the operation of the test instrumentation shall be satisfactory.

8.3.4.3.2 The measured unfiltered vibration shall not exceed the limits of 6.16.6.2 and shall be recorded from N_{ma} to N_{mc}.

8.3.4.3.3 While operating at N_{mc} and at other speeds listed in the test agenda, vibration data shall be acquired to determine amplitudes at frequencies other than synchronous.

a) As a minimum, data shall cover a frequency range from 0.05 to 6 times N_{mc}.

b) If the amplitude of any discrete, nonsynchronous vibration exceeds 20 % of the allowable vibration as defined in 6.16.6.2, the purchaser and the vendor shall mutually agree on requirements for further investigation that may include additional testing and on the equipment's acceptability.

8.3.4.3.4 The mechanical running test shall verify that lateral critical speeds conform to the requirements of 6.16.2.14.

8.3.4.3.5 Any noncritically damped critical speed below the trip speed shall be determined during the mechanical running test and stamped on the nameplate followed by the word "test."

8.3.4.3.6 Synchronous vibration amplitude and phase angle vs. speed shall be recorded during ramp-up and coast down of the 4-hour run.

• a) Both the filtered (one per revolution) and the unfiltered vibration levels shall also be recorded. If specified, these data shall also be furnished in polar form.

b) The speed range covered by these plots shall be from 400 rpm to the driver trip speed.

8.3.4.3.7 For a gas turbine with a modified bearing or rotor configuration or a gas turbine prototype, an unbalanced rotor response test shall be performed as part of the mechanical running test and the results shall be used to verify the analytical model (see 6.16.2.21).

• **8.3.4.3.8** If specified, all real-time vibration data [see Annex B—item 32)] as agreed by the purchaser and vendor shall be recorded and a copy provided to the purchaser.

8.3.5 Optional Shop Tests

Optional shop tests shall be as follows. Test details shall be mutually agreed between the purchaser and the vendor.

• 8.3.5.1 Performance Test

If specified, the gas turbine shall be tested in accordance with ASME PTC 1 and ASME PTC 22, or ISO 2314, as specified.

a) Vibration levels shall be measured and recorded during this test as specified in 8.3.4.1.17 and 8.3.4.1.18.

b) Site rated power and heat rate shall be proven by factory testing.

c) With purchaser approval, field testing (under the supervision of the gas turbine vendor) may be performed (in lieu of factory testing) using agreed upon power and heat rate tolerances.

d) If hardware modifications are required to meet performance, the mechanical run test and performance test shall be repeated.

8.3.5.2 Complete Unit Test

• **8.3.5.2.1** If specified, gas turbine package and all driven components (e.g. compressors, gears, generators) shall be tested together during the complete unit test (also known as a “string test”).

8.3.5.2.2 Unless otherwise specified, the complete unit test shall be unloaded and in accordance with the driven component test requirements (e.g. API 617).

NOTE A loaded test will require definition of the load level, acceptance criteria and usually requires significantly more test equipment.

• **8.3.5.2.3** If specified, torsional vibration measurements shall be made to verify the vendor’s analysis.

8.3.5.2.4 Unless otherwise specified, the complete unit test shall be in addition to separate tests of individual component tests.

NOTE Complete unit test could be in lieu of the individual tests.

8.3.5.2.5 Unless otherwise specified, the following main contract auxiliary systems shall be included in the complete unit test:

a) control panel and software;

b) auxiliary gear;

c) starting equipment;

d) lube oil system;

e) hydraulic oil system;

f) gas fuel system;

g) liquid fuel system;

h) air atomizing system;

i) inlet system;

j) exhaust system;

k) enclosure with the associated equipment.

8.3.5.2.6 Complete unit tests shall include trip and normal shutdown.

8.3.5.2.7 If specified, complete unit tests shall include:

• a) fuel changeover (gas-to-liquid and vice versa);

• b) cold and hot gas turbine restart with site fuel compositions (see 7.9.2 or 7.9.4).

• **8.3.5.2.8** If specified, gas turbine driven generator complete unit tests shall include a generator governor response test.

a) Response tests shall demonstrate governor and gas turbine response at load rejection from 25 %, 50 %, 75 %, and 100 % to 0 % load. Acceptance criteria shall be that the package does not shut down.

b) Response tests shall demonstrate governor and gas turbine response at load acceptance steps as agreed with the purchaser.

c) Vibration data shall be recorded in accordance with 8.3.4.3.3 at 0 %, 25 %, 50 %, 75 %, and 100 % load.

8.3.5.2.9 After the successful completion of the running tests, a borescopic inspection shall be carried out and found to be within the gas turbine manufacturer's new equipment criteria.

8.3.5.3 Sound Level Test

• **8.3.5.3.1** If specified, sound pressure level tests shall be performed in accordance with ASME B133.8 (or ISO 10494).

• **8.3.5.3.2** If specified, sound power level tests shall be performed in accordance with ISO 3744.

NOTE These tests do not typically reflect field sound levels due to shop test environment.

• 8.3.5.4 Rotor Overspeed Test

If specified, an overspeed test of the rotor shall be performed at 120 % of rated speed for 2 minutes. Overspeed tests may be conducted in a vacuum. Suitable nondestructive testing method(s) shall be used on the rotor after the overspeed test to check for cracks, defects, and dimensional changes.

NOTE This test demonstrates the mechanical integrity and vibration behavior of the rotor.

• 8.3.5.5 Auxiliary Equipment Test

If specified, auxiliary equipment (e.g. oil systems, gears, and control systems) shall be tested in the auxiliary equipment manufacturer's shop. Details of the auxiliary equipment tests shall be developed jointly by the purchaser and the vendor.

• 8.3.5.6 Ventilation System Validation

If specified, the enclosure ventilation system shall be tested to demonstrate the safe running of the gas turbine and prove that dilution ventilation satisfies ISO 21789. Vendor shall indicate all specifications used.

• 8.3.5.7 Enclosure Leak Test

If specified, enclosures with fire suppression systems (except water mist) shall be leak (smoke) tested to prove the fire suppressant retention capability of the enclosure. Otherwise, the previous enclosure type test results shall be provided.

NOTE A type test will not reveal manufacturing issues specific to the job enclosure.

• 8.3.5.8 Post-test Inspection

If specified, an inspection of the gas turbine internals by borescope, visually via the inlet and exhaust connections and other access means available shall be performed to document the condition after the running test and documentation shall be provided to the purchaser.

• 8.3.5.9 Inspection of Hub/Shaft Fit for Hydraulically Mounted Couplings

If specified, after the last running test is completed, the shrink fit of hydraulically mounted couplings shall be inspected by comparing hub/shaft match marks to ensure that the coupling hub has not moved on the shaft during the tests.

8.3.5.10 Governor Response and Emergency Overspeed Trip Systems Tests

• **8.3.5.10.1** If specified, response time of the speed governing systems shall be continuously recorded to confirm compliance with 7.5.3.5 and 7.5.3.8.

• **8.3.5.10.2** If specified, response time of the emergency overspeed trip systems shall be recorded (at speeds from 7.5.5.9 to 7.5.5.10) to verify response time in compliance with API 670.

NOTE This test is typically run by manually initiating a trip while the gas turbine is at N_{mc} while recording the response time of the system, i.e. time required for the governor and fuel shut-off valve to close.

• 8.3.5.11 Spare Parts Test

If specified, spare parts, such as gas generator, power turbine, couplings, gears, and bearings, shall be tested the same as the original parts.

• **8.3.5.12 Fire Protection Tests**

If specified, the fire protection systems tests shall confirm compliance with specified (see 7.8.3.2) NFPA or ISO standards.

a) As a minimum, a "functional test" with the fire suppression agent disconnected shall be conducted to ensure that the detectors activate the system components per design.

b) Gas turbine package documentation shall include appropriate functional test documentation.

8.3.5.13 Other Tests and Inspections

Proposal shall list other tests and inspections not listed or defined in this standard. See 9.2.3.2 m).

• **8.3.6 Field Test**

If specified, a field performance test in accordance with ISO 2314 or PTC 22, as specified (see 8.3.5.1), shall be performed to determine gas turbine efficiency and power at site. Vendor shall indicate all test specifications used.

NOTE The Gas Machinery Research Council *Gas Turbine and Compressor Field Testing Guidelines* or other equivalent standards can also be used.

• **8.3.7 Multiple Unit Control Panel Test**

If specified, all unit control panels shall be tested at the unit control panel manufacturer's shop to confirm communication and load sharing logic.

NOTE Panels that need to work together in the field can be tested in the same configuration in the shop.

8.4 Preparation for Shipment

8.4.1 The gas turbine units shall be suitably prepared for the type of shipment specified (see 6.6.2), including blocking of the rotors when necessary.

a) Blocked rotors shall be identified by corrosion-resistant metal tags externally attached with stainless steel wire.

• b) Equipment shall be suitable for outdoor storage for 6 months, or longer if specified, under the conditions in 6.6 from the time of shipment, with no disassembly required before operation except for inspection of bearings and seals.

c) Proposal shall identify all components not suitable for the shipment and storage conditions [see 8.4.1 b)]. See 9.2.3.2 v).

8.4.2 Vendor shall provide the purchaser with the instructions necessary to preserve the integrity of the storage preparation after the equipment arrives at the job site and before startup, as described in API 686.

a) Vendor shall provide a detailed packing list for all individual shipments in advance to permit the purchaser to plan site preparation and storage.

b) Aeroderivative gas generators shall be preserved in accordance with the manufacturer's instructions and shipped in the manufacturer's approved packing.

NOTE Aeroderivative turbine gas generators are commonly shipped separately from the gas turbine package.

8.4.3 The equipment shall be prepared for shipment after all testing and inspections have been completed and the equipment has been released by the purchaser.

• **8.4.3.1** Except for machined surfaces, all exterior surfaces that may corrode during shipment, storage, or in service, shall be given at least one coat of the specified paint. The paint shall not contain lead or chromates.

NOTE Austenitic stainless steels are typically not painted.

8.4.3.2 Exterior machined surfaces, except for corrosion-resistant metals, shall be coated with a suitable rust preventative.

8.4.3.3 The interior of the equipment shall be clean, free from scale, welding spatter, and foreign objects.

8.4.3.4 Rust preventative shall be applied in accordance with the rust preventative and equipment manufacturers' requirements.

8.4.3.5 Internal steel areas of bearing housings and carbon steel oil system auxiliary equipment (if approved by the purchaser), such as reservoirs, vessels, and piping, shall be coated with an oil-soluble rust preventative that is compatible with the lubricating oil. In addition, bearing assemblies shall be fully protected from the entry of moisture and dirt.

8.4.3.6 All openings shall be sealed and protected from damage, ingress of foreign materials, moisture, etc.

a) Flanged openings shall be provided with metal closures at least 5 mm ($^{3}/_{16}$ in.) thick with elastomer gaskets and at least four full-diameter bolts.

b) Each elastomeric gasket shall be equal to the flange diameter.

c) For studded openings, all nuts needed for the intended service shall be used to secure closures.

d) Threaded openings shall be sealed with steel caps or solid-shank steel plugs.

e) Each opening shall be sealed so that the protective cover cannot be removed without the seal being broken.

f) Nonmetallic (such as plastic) plugs or caps shall not be used.

NOTE These are shipping plugs; permanent plugs are covered in 6.13.5.

8.4.3.7 Openings that have been beveled for field welding shall be provided with closures designed to prevent entry of moisture or foreign materials and damage to the bevel.

8.4.3.8 Lifting points and the center of gravity shall be clearly identified on the equipment or equipment package. The recommended lifting arrangement shall be as described in the installation manual (see 9.3.6.2).

• **8.4.3.9** If specified, gas turbine package weight and center of gravity shall be measured with load cells by taking two sets of measurements and the average recorded on the final weight datasheet.

8.4.3.10 The equipment shall be identified with item and serial numbers.

a) Material shipped separately shall be identified with securely affixed, corrosion-resistant metal tags indicating the item and serial number of the equipment for which it is intended.

b) Crated equipment shall be shipped with duplicate packing lists, one on the inside and one on the outside of the shipping container.

8.4.3.11 When a spare rotor is purchased, the rotor shall be prepared for unheated indoor storage for a period of at least 5 years.

a) The rotor shall be treated with a rust preventative and shall be housed in a vapor-barrier envelope with a low-release volatile-corrosion inhibitor.

b) A resilient material 3.0 mm ($^1/_8$ in.) thick shall be used between the rotor and the cradle at the support areas. Tetrafluoroethylene (TFE) or polytetrafluoroethylene (PTFE) shall not be used.

c) Storage methods shall support the rotor to prevent rotor distortion that would require correction.

d) Mark the probe target area barriers with the words: “Probe Area—Do Not Cut.”

• e) If specified, the rotor shall be prepared for vertical storage.

   1) The rotor shall be supported from its coupling end with a fixture designed to support 1.5 times the rotor weight without damage.

   2) Instructions on the use of the fixture shall be included in the installation, operation and maintenance manuals.

NOTE TFE and PTFE could cold flow and impregnate into the surface.

8.4.3.12 Exposed shafts and shaft couplings shall be wrapped with waterproof, moldable waxed cloth or volatile-corrosion inhibitor paper. The seams shall be sealed with oil proof adhesive tape.

8.4.3.13 Complete gas generators, power turbines, or gas turbines shall be shipped in a sealed container.

a) Equipment shall be protected, per manufacturer recommendation, against corrosion (e.g. with desiccant, nitrogen pressurization).

b) Container shall be suitable for long-term storage.

c) Rust preventative shall be applied in accordance with the rust preventative and equipment manufacturers’ requirements.

d) Nitrogen pressure and desiccant indicator shall be visible without opening the container.

e) Humidity labels and shock sensor data shall be accessible without opening the container.

8.4.4 Components (both individual pieces and packages sets) shipped with mounted, preassembled piping, tubing, or wiring shall comply with the requirements of legal or national safety regulations as dictated by location.

8.4.5 Auxiliary piping connections furnished on the purchased equipment shall be identified by the relevant drawing and list.

8.4.6 If vapor corrosion inhibitors in bags are installed in large cavities to absorb moisture, the bags shall be attached in an accessible area for ease of removal. Where applicable, bags shall be installed in wire cages attached to flanged covers, and bag locations shall be indicated on corrosion-resistant metal tags attached with stainless steel wire.

8.4.7 At least one paper and one searchable softcopy of the final manufacturer’s preservation and installation instructions shall be packed and shipped with the equipment.

8.4.8 Connections on auxiliary piping removed for shipment shall be match-marked for ease of reassembly.

8.4.9 Unless otherwise specified, the fit-up and assembly of machine mounted piping, intercoolers, and so forth shall be completed in the vendor's shop prior to shipment.

8.4.10 All enclosures that are on-skid shall be assembled and installed on their skid for shipment to job site. Enclosure auxiliaries (e.g. roof-mounted components, ducting, fans) may be shipped separately.

8.4.11 For gas turbines for offshore installation, shipping units shall be designed for transportation motion requirements (see 6.5.14). A shipping unit is a box, carton, bundle, crate, drum, loose self-supported piece of equipment, etc.

NOTE Transportation loads can be higher than site conditions.

8.4.12 Shipping Unit Markings

• **8.4.12.1** All shipping unit markings shall be in English and other specified language(s).

8.4.12.2 Shipping marks shall be stenciled on two opposite sides of the shipping unit.

8.4.12.3 Easy to read, weatherproof lettering shall be at least 3 in. (7.6 cm) high.

8.4.12.4 Shipping units that cannot be stenciled directly shall have attached corrosion-resistant metal tags with raised markings.

8.4.12.5 Shipping units shall be marked with industry standard cautionary symbols indicating center of gravity, sling or lifting points, top heavy packages, fragile and liquid contents, moisture sensitive contents etc., per ASTM D5445-05 *Standard Practice for Pictorial Markings for Handling of Goods*.

8.4.12.6 Shipping unit markings shall include:

a) purchaser's purchase order number and tag number;

b) shipping unit piece number;

c) gross weight;

d) dimensions;

e) purchaser's project name.

9 Vendor's Data

9.1 General

• **9.1.1** The content of proposals, meeting frequency, and vendor data content/format shall be as specified. See Annex B.

9.1.2 Vendor shall complete and forward the VDDR form (see Annex B) to the addresses noted on the inquiry or order.

a) The VDDR form shall detail the schedule for transmission of drawings, curves, and data as agreed to at the time of the proposal or order, as well as the number and type of copies required by the purchaser.

b) All information submitted in the proposal shall be updated with as-built data and included in the VDDR.

• **9.1.3** The following information shall be identified on vendor data transmittal (cover) letters and in the title blocks or pages:

a) purchaser's/user's corporate name;

b) job/project number;

c) equipment service name and item number;

d) inquiry or purchase order number;

• e) any other specified identifier(s);

f) vendor's identifying proposal number, shop order number, serial number, or other reference required to identify return correspondence completely.

9.1.4 A coordination meeting shall be held, preferably at the vendor's plant, within 4 to 6 weeks after the purchase commitment. Unless otherwise specified, the vendor will prepare and distribute an agenda prior to this meeting, which, as a minimum, will include review of the following items:

a) purchase order, scope of supply, unit responsibility, and subvendor items;

b) datasheets;

c) applicable specifications and previously agreed upon exceptions;

d) schedules for transmittal of data, production, and testing;

e) quality assurance program and procedures;

f) inspection, expediting, and testing;

g) schematics and bills of material of auxiliary systems;

h) physical orientation of the equipment, piping, and auxiliary systems;

i) coupling selections;

j) thrust bearing sizing and estimated loading;

k) rotordynamic analysis;

l) other technical items.

9.2 Proposals

9.2.1 General

• a) Vendor shall transmit a searchable softcopy of the proposal to the addressee identified in the inquiry documents. If specified, the vendor shall mail the specified number of hardcopies to the addressee identified in the inquiry documents.

b) As a minimum, proposal shall contain the data in 9.2.2 through 9.2.4 as well as a specific statement that the system and all its components are in strict accordance with this standard.

c) If the system and components are not in strict accordance, the vendor shall include a list that details and explains each deviation.

d) Vendor shall provide details to enable the purchaser to evaluate any proposed alternative designs. See 1.2 and 7.3.3.5.

e) All correspondence shall be clearly identified per 9.1.3.

9.2.2 Drawings

9.2.2.1 The drawings indicated on the VDDR form shall be included in the proposal. As a minimum, the following data shall be furnished.

a) A general arrangement or outline drawing for each major skid or system, showing overall dimensions, maintenance access dimensions, overall weights, erection weights, and maximum maintenance weights (indicated for each piece). Typical drawings may be used.

b) The direction of rotation and the size and location of major purchaser connections shall also be indicated.

c) Cross-sectional drawings showing details of the gas turbine proposed.

d) Schematics of all auxiliary systems, such as fuel, lube oil, water/steam injection, control, and electrical systems. Bill of materials shall be included.

e) Methods of lifting the assembled machine or machines and major components. This information may be included on the drawings specified in item a).

9.2.2.2 If typical drawings, schematics, and bill of materials are used, they shall be marked up to show the correct weight and dimension data and to reflect the actual equipment and scope proposed.

9.2.3 Technical Data

9.2.3.1 All the technical data shall be given in same units of measurement (SI or USC) as the purchaser's datasheets, alternate units may be included in parentheses (see 5.1).

9.2.3.2 Proposal shall include the following technical data.

a) Purchaser's datasheets with complete vendor's information entered thereon and literature that fully describes the details of the offering.

b) Purchaser's noise datasheet.

c) VDDR (see Annex B) indicating the schedule according to which the vendor agrees to transmit all the data included in the contract.

d) Schedule for the shipment of the equipment, in weeks after receipt of the order.

e) List of the major wearing components showing interchangeability with other purchaser units.

f) List of spare parts recommended for commissioning, startup, and operation.

g) List of special tools furnished for maintenance [see 6.5.6 d)]. Any metric items included in the offering shall be identified.

h) Statement of any special weather protection and winterization required for startup, operation, and periods of idleness under the various site conditions specified (see 6.1.14 and 6.6). The statement shall show the protection to be furnished by the purchaser, as well as the protection that is included in the vendor's scope of supply.

i) A complete tabulation of utility requirements, such as those for steam, water, electricity, air, gas, and lube oil, including the quantity of lube oil required and the supply pressure, the heat load to be removed by the oil, and the nameplate power rating, operating power rating, and operating power requirements of auxiliary drivers. Approximate data shall be defined and clearly identified as such. See 6.5.12, 7.5.6.7, 7.7.2.9.3.6, and 7.7.2.9.4.7 a).

j) Water and steam cleanliness requirements (e.g. for evaporative cooling, power augmentation, emissions control, water washing), if applicable. See 6.2.9 and 7.9.6.2.1.

k) List of materials of construction of components in contact with purchaser corrosive agents as described in 6.20.

l) Description of the tests and inspection procedures for materials as required by 6.20.8.

m) Proposal requirements from this document (i.e. 6.1.3, 6.1.5, 6.1.6, etc.) and description of special requirements, as outlined in the purchaser's inquiry.

n) A list of similar gas turbines installed and operating under analogous conditions to those offered in the proposal.

o) Startup, shutdown, or operating restrictions required to protect the integrity of the equipment. See 6.1.20, 6.14.3.3, and 6.14.3.4.8.

p) Vibration limits per 6.16.6.1 and 6.16.6.2.

q) As a minimum, the vendor shall include the following data for gas turbine inlet air filtration system:

   1) manufacturer and model number or type for the filter housing and filters (if not the same);

   2) materials of construction and description of the acoustic insulation (see 6.20.3, 6.20.4, and 6.20.7);

   3) coatings (see 6.20.3, 6.20.4, and 6.20.7);

   4) system filtration efficiency (cleanliness);

   5) pressure drop of each filter section (clean) (see 7.7.2.2.6);

   6) alarm and trip set point for maximum filter differential pressure;

   7) total pressure drop of filter ducting system measured at bell mouth intake;

   8) average air flow velocity at filter housing inlet and at media face;

   9) weights and dimensions.

r) Recommendation for anti-icing, if applicable.

s) Expected exhaust temperature and corresponding mass flow.

t) Extent of component removal required for combustion system maintenance.

u) Recommended inspection and maintenance intervals, as applicable. As a minimum, the following data shall be provided:

   1) inspection tasks as a function of fired hours;

   2) required preventive maintenance procedures during inspection and parts to be renewed and/or replaced;

   3) expected duration of shutdown for each required maintenance procedure with the associated number of people and work schedule required for the stated duration [see 6.5.6 f)];

   4) effects of multiple starts on inspection intervals and engine life;

   5) estimated nonrecoverable decrease in output that may be expected over the life of the gas turbine due to fouling of the compressor and deterioration of the turbine.

v) Details of the preparation of the equipment for shipment and storage at the site prior to commissioning [see 8.4.1 c)].

• w) If specified, the vendor shall include a probabilistic spare parts optimization analysis based on failure rates supported by inventory histories for the model being supplied.

• x) If specified, the vendor shall include in the proposal failure modes and effects analysis (FMEA) to address major failure modes of the proposed equipment train.

• y) If specified, the vendor shall include a lifecycle analysis based on assumed energy requirement documented in the report. The analysis shall be over specified service life (see 6.1.2) and based on the specified discount rate.

9.2.4 Curves

9.2.4.1 Proposal shall contain a power output vs. speed curve at site rated conditions in the format shown in Figure 17, Figure 18, or Figure 19, as applicable.

9.2.4.2 Additional curves shall be presented showing site rated power and speed at maximum and minimum site ambient temperatures (see 6.6) and showing both parameters for each fuel (see 7.9).

9.2.4.3 All curves shall include power adjustments for proposed inlet and exhaust pressure losses, fuel compositions (see 7.9.2 or 7.9.4), and anti-icing system operation (if applicable).

9.2.4.4 If specified, the following curves shall also be furnished.

• a) A speed vs. torque curve for the power-output shaft at site rated conditions. For single-shaft designs, the required starting torque and the combined torque to load produced by the starting device plus the gas turbine after light off shall be indicated. See Annex B (VDDR)—item 20.

• b) Power output vs. speed curves (see 9.2.4.1) for increments of steam or water injection (e.g. 0%, 25%, 50%, 75%, 100% steam or water injection). See 9.2.4.3 and Annex B (VDDR)—item 21.

• c) Exhaust flow and temperature vs. inlet air temperature [from minimum to maximum temperature (see 6.6)]. See 9.2.4.3 and Annex B (VDDR)—item 55.

• d) Run-down curves showing exhaust flow and temperature vs. time after trip, under full load and no load initial conditions. See Annex B (VDDR)—item 56.

NOTE Run-down parameters for two-shaft machines can be measured during a mechanical run test. However, the inertia and run-down load for a single-shaft turbine is not always available during a mechanical run test.

• e) CO_2, hydrocarbons, PM, SO_X, NO_X, and CO emission curves showing concentration in the exhaust gas vs. percentage load at minimum and maximum temperature (see 6.6). See Annex B (VDDR)—item 57.

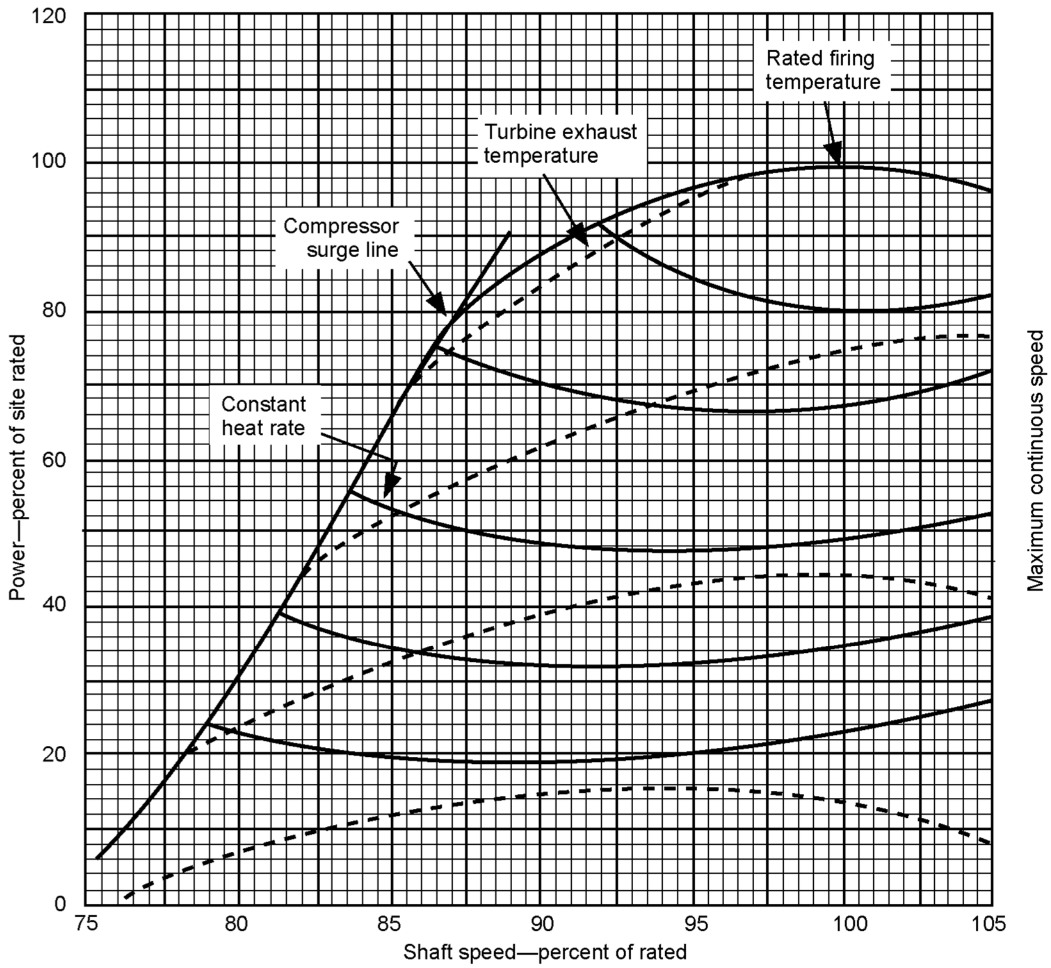


Figure 17—Performance Curves for a Single-shaft Gas Turbine

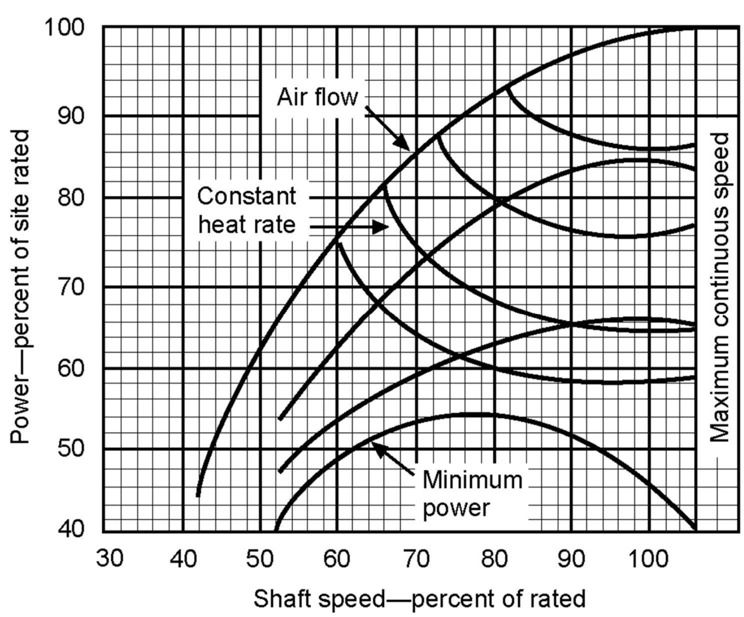


Figure 18—Performance Curves for a Multiple-shaft Gas Turbine (Constant Exhaust Temperature)

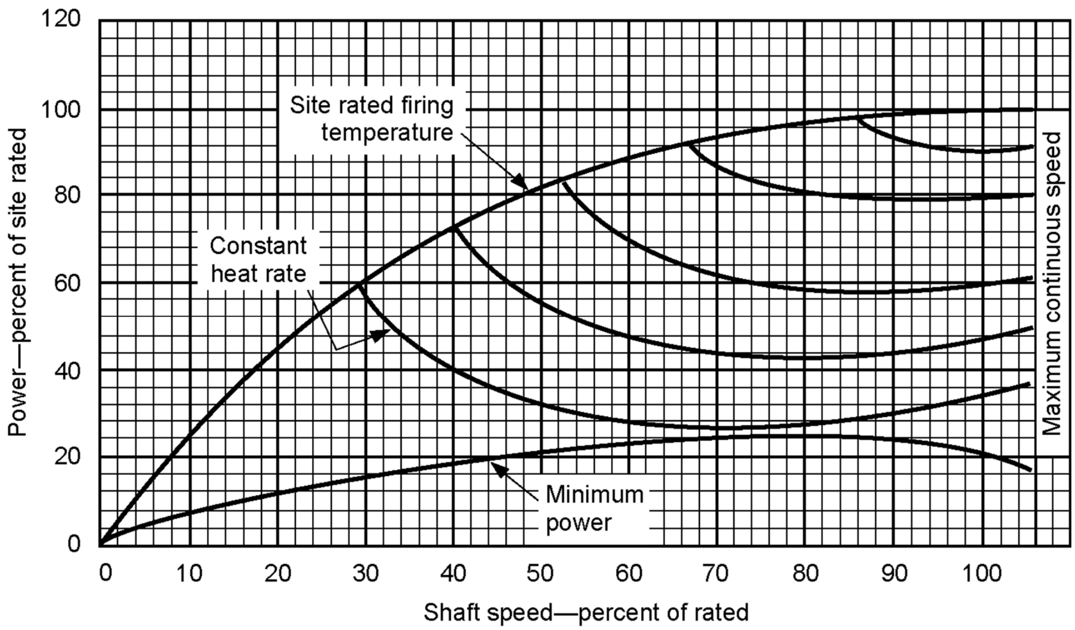


Figure 19—Performance Curves for a Multiple-shaft Gas Turbine (Varying Exhaust Temperature)

9.3 Contract Data

9.3.1 General

9.3.1.1 The contract data shall be furnished by the vendor in conformance with Annex B.

9.3.1.2 Each drawing shall have a title block in its lower right-hand corner that shows the date of issuance, a reference to all identification data listed in 9.1.3, the revision number and date, and the title.

9.3.1.3 The other documents, not in a drawing format, such as bill of material, datasheets, etc. shall include identification data listed in 9.1.3, including revision history.

9.3.1.4 The purchaser will promptly review the vendor's data when he receives them; however, this review shall not constitute permission to deviate from any requirements in the order.

9.3.1.5 All deviations shall be specifically agreed upon in writing.

• **9.3.1.6** After all the contract data have been reviewed, the vendor shall transmit a searchable softcopy of the contract data to the addressee identified in the Purchase Order. Vendor shall mail the specified number of hardcopies to the addressee specified identified in the Purchase Order.

9.3.1.7 A complete list of all vendor data shall be included with the first issue of major drawings. This list will contain titles, drawing or document numbers, and a schedule for transmission of all data the vendor shall furnish.

9.3.1.8 The drawings or data titles shall be cross-referenced as closely as is practical to the corresponding items in Annex B.

9.3.2 Drawings

9.3.2.1 The drawings furnished shall contain sufficient information so that with the drawings and the manuals in 9.3.6, the purchaser can properly install, operate, and maintain the ordered equipment.

9.3.2.2 Drawings shall be clearly legible, shall be identified in accordance with 9.3.1.1, and shall be in accordance with the ASME Y14.2. Vendor shall describe in the proposal if an alternative standard is used.

9.3.2.3 As a minimum, each drawing shall include the details for that drawing listed in Annex B.

• **9.3.2.4** Drawings shall be provided in the specified electronic format(s).

9.3.2.5 Drawings shall be formatted and legible when printed on 11" × 17" (A3) or 8 $^1/_2$" × 11" (A4) paper.

9.3.3 Technical Data

The data shall be submitted in accordance with Annex B and identified in accordance with 9.3.1.1. Any comments on the drawings or revisions of specifications that necessitate a change in the data shall be noted by the vendor. These notations will result in the purchaser's issue of completed, corrected datasheets as part of the order specifications.

9.3.4 Progress Reports

Unless otherwise specified [VDDR Annex B—item 44)], vendor shall submit progress reports to the purchaser at 6-week intervals.

9.3.5 Parts Lists and Recommended Spares

9.3.5.1 Vendor shall submit complete parts lists for all equipment and accessories supplied, including the vendor's and the part manufacturer's unique part numbers and materials of construction.

9.3.5.2 Materials shall be identified in conformance with 6.20.1.

9.3.5.3 Each part shall be completely identified and shown on cross-sectional or assembly-type drawings so that the purchaser may determine the interchangeability of the part with other equipment.

9.3.5.4 Parts that have been modified from standard dimensions and/or finished to satisfy specific performance requirements shall be uniquely identified by part number for interchangeability and future duplication purposes.

9.3.5.5 Vendor shall indicate, on the above parts lists, which parts are recommended spares for startup and normal maintenance [see 9.2.3.2 f)].

9.3.5.6 Vendor shall forward the lists to the purchaser promptly after receipt of the reviewed drawings and in time to permit order and delivery of the parts before field startup.

9.3.5.7 The transmittal letter shall be identified with the data in 9.1.3.

9.3.6 Installation, Operation, Maintenance, and Technical Data Manuals

9.3.6.1 General

Sufficient written instructions and a list of all drawings shall be provided to enable the purchaser to correctly install, operate, and maintain all of the equipment ordered.

a) This information shall be compiled in a manual or manuals with a cover sheet that contains all reference-identifying data listed in 9.1.3, an index sheet that contains section titles, and a complete list of referenced and enclosed drawings by title and drawing number.

b) The manual shall be prepared for this specific installation (see 6.6).

• c) One searchable softcopy version of each manual shall be provided in the specified format with bookmarks.

1) To maximize text search capability, scanned pages shall be minimized.

2) PLC and HMI programming software shall be provided.

3) A backup copy of all PLC and HMI programs and configuration files shall be provided in the software's native format.

9.3.6.2 Installation Manual

Installation manual shall include the following.

a) Any special information required for proper installation design that is not on the drawings shall be compiled in a manual that is separate from the operating and maintenance instructions.

b) This manual shall be forwarded at a time that is mutually agreed upon in the order but not later than the final issue of prints.

c) The installation manual shall contain information such as special alignment and grouting procedures, utility requirements (including quantities), and all other installation data, including the drawings and data in 9.3.2 and 9.3.3.

d) The installation manual shall clearly identify the locations of all lifting points and lifting lugs.

e) The installation manual shall identify weights, dimensions, and centers of gravity.

f) The installation manual shall include drawings, data, procedures, or other means for the safe handling, unloading, and maintenance of the package.

9.3.6.3 Operating and Maintenance Manual

Operating and maintenance manuals shall conform to the following.

a) Manuals containing operating and maintenance data shall be forwarded at a time mutually agreed upon by the purchaser and the vendor, but no later than shipment.

b) One set of operating and maintenance manuals shall accompany each unit at shipment.

c) Operating and maintenance manuals shall include a section that provides special instructions for operation at extreme environmental conditions, such as temperatures (see 6.6).

d) Operating and maintenance manuals shall include centers of gravity and rigging provisions to permit the removal of the top half of casings, rotors, and any subassemblies that weigh more than 135 kg (300 lbm).

e) Operating and maintenance manuals shall include all the data listed in Annex B.

9.3.6.4 Technical Data Manual

A technical data manual shall be provided at a time mutually agreed upon by the purchaser and the vendor (see Annex B for detail requirements).

Annex A
(informative)

Typical Datasheets

COMBUSTION GAS TURBINE (API 616-6th)	JOB NO. ____ ITEM NO. ____	REV
	PURCHASE ORDER NO. ____	
DATASHEET SI UNITS	SPECIFICATION NO. ____	
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APPLICABLE TO: ○ PROPOSAL ○ PURCHASE ○ AS-BUILT ○ TECH READINESS LEVEL (6.1.1.1) ____
○ FOR (9.1.3) ____ ○ UNIT (9.1.3) ____ ○ TRL DOCUMENTATION REQUIRED (6.1.1.2)
○ SITE (9.1.3) ____ ○ POWER MARGIN (6.1.7) ____ % ○ SERVICE LIFE (6.1.2, 9.2.3.2.y) ____ yrs
○ SERVICE (9.1.3) ____ ○ NUMBER REQUIRED ____ ○ MINIMUM AVAILABILITY (6.1.5) ____ %
○ CONTINUOUS ○ INTERMITTENT ○ STANDBY ○ DRIVEN EQUIPMENT ____ ○ MINIMUM RELIABILITY (6.1.5) ____ %
☐ MANUFACTURER ____ ☐ MODEL ____ ☐ SERIAL NUMBER ____ ☐ ISO RATING (3.1.26) ____ MW ____ RPM
NOTE: INFORMATION TO BE COMPLETED: ○ BY PURCHASER ☐ BY MANUFACTURER ☐ BY MFR IF NOT BY PURCHASER

LOCATION AND SITE CONDITIONS (6.1, 6.6)

○ INDOOR ○ OUTDOOR ○ UNDER ROOF ○ PARTIAL SIDES ○ IN BUILDING ○ GRADE ○ MEZZANINE ○ HEATED ○ UNHEATED
○ OTHER ____

○ EXTREME MAXIMUM AMBIENT TEMPERATURE ____ °C ○ BUILDING CODE (6.5.13)
○ EXTREME MINIMUM AMBIENT TEMPERATURE ____ °C ____
○ MINIMUM DESIGN METAL TEMPERATURE (6.25.7) ____ °C
○ PIPING STANDARD (6.13.1) ____
○ ALTITUDE (6.1.24) ____ m ☐ WINTERIZATION REQD ☐ TROPICALIZATION REQD (7.5.8.11, 7.7.2.3.3)

GAS TURBINE ARRANGEMENTS (6.1.10 Figure 1):
☐ SINGLE SHAFT
☐ TWO-SHAFT (WITH FREE POWER TURBINE) ☐ THREE-SHAFT (WITH FREE POWER TURBINE)
☐ TWO-SHAFT (WITHOUT FREE POWER TURBINE) ☐ THREE-SHAFT (WITHOUT FREE POWER TURBINE)

SEISMIC DESIGN CRITERIA (6.6.3, 7.7.1.10)
○ APPLICABLE CODE ____ ○ APPLICABLE SPECIFICATION ____

WIND DESIGN CRITERIA (6.6.4, 7.7.1.10)
○ APPLICABLE CODE ____ ○ APPLICABLE SPECIFICATION ____
○ NON OPERATING EXTREME WIND DESIGN SPEED (6.6.5) ____ km/h ____
(See also Page 16)

ELECTRICAL AREA CLASSIFICATION (6.5.4)
○ UNCLASSIFIED ○ HAZARDOUS
○ CLASS ____ DIV/ZONE ____ GROUP ____ TEMP. CODE ____

ELECTRICAL CODES (6.5.3)
○ NFPA 70 (NEC) ○ ATEX 2014/34/EU
○ IEC 60079 ○ CSA C22-1-06
○ OTHER ____

COMPONENTS IN UNCLASSIFIED LOCATION (7.5.1.6)
CODE: ○ NEC 500 ○ NEC 505 ○ IEC
○ OUTSIDE GT ENCLOSURES CLASS ____ DIV/ZONE ____ GROUP ____ TEMP. CODE ____
○ INSIDE GT ENCLOSURES CLASS ____ DIV/ZONE ____ GROUP ____ TEMP. CODE ____
○ THIRD-PARTY CERTIFICATION ____

UNUSUAL CONDITIONS: (6.1 and 6.6):
○ DUST ○ FUMES
○ APPLICABLE SPECIFICATION FOR DUST LOADING ____
○ APPLICABLE SPECIFICATION FOR SNOW/ICE LOADING (7.7.1.10) ____

NOISE LIMIT REQUIREMENTS: (6.3.1, 6.3.2)
○ GAS TURBINE ENCLOSURE ____ dBA ○ PRESSURE ○ POWER
○ INLET SYSTEM ____ dBA ○ PRESSURE ○ POWER
○ EXHAUST SYSTEM ____ dBA ○ PRESSURE ○ POWER
○ OVERALL FAR FIELD REQUIREMENT

DOCUMENT HIERARCHY: (5.3)
○ 1 ____ 5 ____
2 ____ 6 ____
3 ____ 7 ____
4 ____ 8 ____
○ VENDOR HAVING UNIT RESPONSIBILITY (4) ____
○ OTHER

PAINTING: (8.4.3.1)
○ MANUFACTURER'S STANDARD
○ MANUFACTURER'S STANDARD FOR MARINE ENVIRONMENT
○ OTHER ____

CASING CONNECTIONS
CASING BOLT THREADING (6.8.1)
☐ ISO 261 ☐ ASME B1.1 ☐ MIL-S-8879
THREADS TYPE ☐ TAPERED ☐ STRAIGHT
CASING FLANGES: ☐ ISO ☐ ASME
MACHINED & STUDDED ☐ ISO ☐ ASME

SHIPMENT: (8.4) ○ TRUCK ○ RAIL ○ SHIP
○ ENVIRONMENTAL CONDITIONS (6.6.2) ____
○ TRANSPORTATION LOADS (6.5.14, 7.7.1.10) ____
○ DOMESTIC ○ EXPORT ○ EXPORT BOXING REQUIRED
○ DURATION OF OUTDOOR STORAGE IF MORE THAN 6 MONTHS (8.4.1.b) ____

SPARE ROTOR ASSEMBLY PACKAGED FOR (8.4.3.11)
○ DOMESTIC SHIPMENT ○ EXPORT SHIPMENT ○ VERTICAL STORAGE (8.4.3.11.e)
○ OTHER SPECIFIED LANGUAGE FOR SHIPPING UNIT MARKINGS (8.4.12.1) ____

REMARKS: ____

REMARKS: ____

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GENERAL

CYCLE: REGEN SIMPLE EXHAUST HEAT RECOVERY (7.7.3.1.1.b)

DRIVEN EQUIPMENT POWER RANGE: ______ MW DRIVEN EQUIPMENT SPEED RANGE ______ RPM

GAS TURBINE DRIVER OUTPUT SHAFT SPEED RANGE (6.1.15, 6.1.16, 7.5.3.4) ______ RPM

OPERATION ATTENDED UNATTENDED

POTENTIAL MAXIMUM POWER (3.1.48) ______ MW LIMITING CONDITIONS ______

PERFORMANCE

STEAM OR WATER INJECTION

EMISSIONS (6.2.7) AUGMENTATION (6.2.7)

PERFORMANCE PARAMETERS (6.6)			SITE RATED (3.1.65)	NORMAL OPERATING (3.1.39)	SITE MAX TEMP	SITE MIN TEMP				SITE MIN TURNDOWN
DRIVEN EQUIPMENT PWR	MW	(6.1.7, 7.9.6.1)								
POWER FACTOR (GEN-SET)		(6.1.23)								
INLET DP	mm H_2O	(7.7.2.1.3.2)								
EXHAUST DP	mm H_2O	(7.7.3.1.1)								
AIR DRY BULB TEMP (INLET)	°C	(6.1.24)								
GT INLET AIR COOLING (Y/N)										
GT INLET AIR HEATING (Y/N)										
GT INLET TEMP	°C									
RELATIVE HUMIDITY	%	(6.1.24)								
BAROMETRIC PRESS	kPa	(6.1.24)								
GT OUTPUT SHAFT POWER	MW									
GG SHAFT SPEED	RPM									
PT OUTPUT SHAFT SPEED	RPM	(6.1.15)								
HEAT RATE (LHV)	kJ/kW-h									
NO_X EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
CO EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
CO_2 EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
SO_X EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
HYDROCARBON EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
PARTICULATE EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
FIRING TEMPERATURE	°C									
AIR FLOW	kg/s									
GG EXHAUST TEMP	°C									
PT EXHAUST FLOW	kg/s									
PT EXHAUST TEMP	°C									
FUEL TYPE		(6.1.24)								
FUEL FLOWRATE	kg/h									
FUEL TEMPERATURE	°C									
STEAM FLOW	kg/h	(6.2.7)								
WATER FLOW	m³/h	(6.2.7)								

AIR COMPRESSOR:

STAGES ______ MAXIMUM TIP SPEED ______ m/s

TYPE ______ PRESSURE RATIO ______

CASING SPLIT (6.7.3) AXIAL RADIAL

ROTOR SOLID BUILT UP

TURBINE:

STAGES ______ MAXIMUM TIP SPEED ______ m/s

CASING SPLIT (6.7.3) AXIAL RADIAL

ROTOR SOLID BUILT-UP

MATERIALS:

COMPRESSOR CASING ______

TURBINE CASING ______

COMBUSTOR LINER ______

COMBUSTOR HEAT SHIELD

COMBUSTORS: (6.10)

NUMBER OF COMBUSTORS ______

FUEL NOZZLES PER COMBUSTOR ______

CONFIGURATION ______

MAXIMUM ALLOWABLE TEMP. VARIATION ______ °C

APPLICABLE PLANE ______

COMBUSTOR FLAMEOUT DETECTION (7.5.9.8.2)

FLAME TEMPERATURE SPEED CHANGE

REMARKS: ______

REMARKS: ______

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1	**FUEL SYSTEM** (7.9)					
2	TYPE ○ GAS (7.9.1.2) ○ LIQUID (7.9.3) ○ DUAL (7.9.3.10, 7.9.5)					
3	**DUAL SYSTEM REQMTS** (7.9.3.10, 7.9.5) ○ GAS/GAS ○ LIQUID/GAS ○ LIQUID/LIQUID					
4	○ FUEL GAS COMPRESSION SYSTEM REQD (7.9.1.2.1.4)					☐ MAX TRANSFER TIME (7.9.5.2.a) ______ sec
5						☐ MIN TRANSFER TIME (7.9.5.2.b) ______ sec
6	**GAS FUELS** (7.9.2)					**GAS FUEL SYSTEM AND COMPONENTS**
7	○ HC DEW PT,°C @ kPa		@	@	@	
8						☐ MANUAL ISOLATION VALVE MFR (7.9.1.2.1.1)
9	○ FUEL ANALYSIS - MOL % (6.1.24.e, 7.9.2.1)					○ VALVE PRESSURE PROVING (7.9.1.2.7.4)
10	COMPOSITION (7.9.1.1.2)	MW	NORMAL	START-UP	ALTERNATE	○ EXTERIOR VENT VALVE (7.9.1.2.5.3)
11	AIR	29				☐ PRIMARY FAST SHUT OFF MFR (7.9.1.2.4.4)
12	OXYGEN	32				☐ LEAK TIGHT SHUT OFF MFR (7.9.1.2.4.3)
13	NITROGEN	38				○ FUEL SHUT-OFF VALVE SUPLLIED BY VENDOR (7.9.1.2.5.1)
14	WATER VAPOR	18				☐ MANUFACTURER
15	CARBON MONOXIDE	28				○ DUAL Y-TYPE STRAINERS REQ'D (7.9.1.2.6.2)
16	CARBON DIOXIDE	44				○ GAS FUEL HEATER SUPPLIED BY VENDOR (7.9.2.5.4)
17	HYDROGEN	2				☐ LIQUID FUEL HEATER SUPPLIED BY PURCHASER (7.9.3.13.2)
18	METHANE	16				
19	ETHYLENE	26				☐ GAS FUEL SUPERHEAT REQMT (7.9.2.1.3) ______ °C
20	ETHANE	30				○ COALESCING FILTER SIZED FOR DEW POINT CONTROL (7.9.2.2.2)
21	PROPYLENE	42				○ RATE OF CHANGE OF WI (7.9.2.4.2) ______ MJ/m³
22	PROPANE	44				○ RATE OF CHANGE OF MWI (7.9.2.4.2) ______ MJ/m³/√K
23	I-BUTANE	58				○ SPECIAL FUEL ANALYSIS EQUIPMT SUPPLIED BY VENDOR (7.9.2.4.3)
24	N-BUTANE	58				☐ CALORIMETER
25	I-PENTANE	72				☐ GAS CHROMATOGRAPH
26	N-PENTANE	72				☐ WOBBE METER
27	HEXANE PLUS					○ FUEL GAS LINE PRE-START PURGE SYSTEM (7.9.1.2.1.5)
28						○ FUEL GAS PRESSURE REGULATOR SUPPLIED BY VENDOR(7.9.1.2.1.6)
29	TOTAL	%	**100.00**	**100.00**	**100.00**	○ VALVE CERTIFICATION REGULATORY AGENCY (7.9.1.2.1.3)
30	AVG. MOL. WT.					
31	☐ LHV	MJ/m^3				
32	☐ WOBBE INDEX	MJ/m^3				**REMARKS:**
33	☐ FUEL TEMP REQ'D	°C				
34	☐ FUEL PRESS REQ'D	kPag				
35						**PIPING, TUBING & DESIGN DETAILS**
36						NACE STANDARD (6.20.13)
37	**CONTAMINENTS** (7.9.1.1.3, 7.9.2.2)					○ NACE MR0103 ○ MR0175
38	○ TAR	PPM				○ FUEL SYSTEM FLANGE RATING
39	○ CARBON BLACK	PPM				○ PIPING / TUBING GRADE
40	○ COKE	PPM				○ TUBE FITTING MFR (7.6.1.9)
41	○ SOLIDS	PPM				○ MAXIMUM VENT BACKPRESSURE (7.9.1.2.4.7) ______ kPag
42	○ NAPHTHALENE	PPM				
43	○ GAS HYDRATES	PPM				**"SHIP LOOSE" FUEL GAS SYSTEM COMPONENTS**
44	○	PPM				☐ Y-TYPE STRAINERS
45	**CORROSIVE AGENTS** (7.9.1.1.3, 7.9.2.3, 6.20.13)					☐ DUPLEX FUEL GAS FILTERS
46	○ HYD SULFIDE (H2S)	PPM				☐ PIPING
47	○ SULPHUR DIOXIDE	PPM				☐ HEATERS
48	○ SULPHUR TRIOXIDE	PPM				☐ GAS ANALYSIS EQUIPMENT
49	○ TOTAL SULPHUR	PPM				
50	○ ALKALI METALS	PPM				**REMARKS:**
51	○ CHLORIDES	PPM				
52	○	PPM				

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FUEL SYSTEM (7.9)

TYPE ○ GAS (7.9.1.2) ○ LIQUID (7.9.3) ○ DUAL (7.9.3.10, 7.9.5)

DUAL SYSTEM REQMTS (7.9.3.10, 7.9.5) ○ GAS/GAS ○ LIQUID/GAS ○ LIQUID/LIQUID

○ FUEL GAS COMPRESSION SYSTEM REQD (7.9.1.2.1.4) ☐ MAX TRANSFER TIME (7.9.5.2.a) ________ sec

☐ MIN TRANSFER TIME (7.9.5.2.b) sec

LIQUID FUEL SYSTEM (7.9.3)

FUEL GRADES (7.9.1.1.2, 7.9.4.1):

- ○ ASTM D2880 GRADE (7.9.4.3)
  - ○ GRADE 0-GT
  - ○ GRADE 1-GT
  - ○ GRADE 2-GT
  - ○ GRADE 3-GT
  - ○ GRADE 4-GT
- ○ ASTM D1655 (7.9.4.3)
  - ○ JET A OR JET A-1
  - ○ JET B
- ○ OTHER, INDICATE ANALYSIS (7.9.4.3)
- ○ FUEL SHUT-OFF VALVE SUPPLIED BY VENDOR(7.9.3.5.2)
- ○ SECOND STRAINER REQUIRED (7.9.3.7.2)
- ○ FUEL TRANSFER EQUIPMENT SUPPLIED BY VENDOR(7.9.3.14)

LIQUID FUEL TREATMENT REQUIRED ☐ YES ☐ NO

☐ LIQUID FUEL HEATER SUPPLIED BY PURCHASER (7.9.3.13.1, 7.9.3.13.2)

☐ LIQUID FUEL PRESS RANGE ________ kPag

REMARKS:

FUEL PUMP SYSTEM DETAILS

☐ FUEL PUMP PRV SET POINT ________ kPag

☐ PUMP RATED CAPACITY ________ l/min

PIPING, TUBING & DESIGN DETAILS

NACE STANDARD (6.20.13)

○ NACE MR0103 ○ MR0175

- ○ FUEL SYSTEM FLANGE RATING
- ○ PIPING / TUBING GRADE
- ○ TUBE FITTING MFR (7.6.1.9)
- ○ MAXIMUM VENT BACKPRESSURE (7.9.1.2.4.7) kPag

LIQUID FUEL ANALYSIS (7.9.4)

FUEL ANALYSIS DATA (7.9.4.1) PROPERTY (7.9.1.1.2, 7.9.1.1.3)	ASTM METHOD	MEASURED VALUE
VISCOSITY, cSt @ 38°C	D-445	○
DISTILLATION DATA	D-86	
10% / 50% / 90% RECOVERY, °C MAX		○
END POINT, °C MAX		○
SULFUR CONTENT %WEIGHT, MAX. (SELECT APPL. METHOD)		
BOMB METHOD	D-129	○
LAMP METHOD	D-1266	○
HIGH-TEMP METHOD	D-1552	○
CARBON RESIDUE (ON 10% BOTTOMS)		
% WT. MAX.		○
CONRADSON	D-189	○
RAMSBOTTOM	D-524	○
COPPER STRIP CORROSION PLATE	D-130	
3 HOURS AT 38°C MAXIMUM		○
AROMATIC CONTENT % WT	D-5186	○
ASH CONTENT	D-482	○
SPECIFIC GRAVITY, kg/m^3 @ 15°C	D-4052	○
FLASH POINT, °C	D-56	○
CLOUD POINT, °C	D-2500	○
POUR POINT, °C	D-97	○
WATER	D-95	○
PARTICULATES, mg/100 ml	D-2276	○
TRACE METALS (ATOMIC		
ABSORPTION PREFERRED)	D-3605	○
SODIUM		○
POTASSIUM		○
VANADIUM		○
CALCIUM		○
LEAD		○
OTHER METALS		○
LOWER HEATING VALUE, MJ/kg	D-2382	○
REID VAPOR PRESSURE, bar	D-323	○
OLEFIN CONTENT, % VOL	D-1319	○

REMARKS:

REMARKS:

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CONSTRUCTION FEATURES - ROTOR No. 1 DESCRIPTION:

☐ SPEEDS: 100 % SPEED ______ RPM
☐ MAX. CONT. ______ RPM ☐ TRIP ______ RPM
☐ LATERAL CRITICAL SPEEDS (DAMPED)(6.16.2.1)

FIRST CRITICAL		RPM		MODE
SECOND CRITICAL		RPM		MODE
THIRD CRITICAL		RPM		MODE
FOURTH CRITICAL		RPM		MODE

☐ PROTOTYPE OR MODIFIED ROTOR SUPPORT (6.16.2.21)
○ TRAIN LATERAL ANALYSIS (6.16.2.8)
○ TRAIN TORSIONAL ANALYSIS (6.16.4.2) TORS SF (6.16.4.8) ______
☐ TORSIONAL CRITICAL SPEEDS:

FIRST CRITICAL		RPM
SECOND CRITICAL		RPM
THIRD CRITICAL		RPM
FOURTH CRITICAL		RPM

○ PURCHASER REVIEW OF CAMPBELL/GOODMAN DIAGRAM (6.14.3.4.6)
VIBRATION: (6.16.6.2) (6.16.6.3)
☐ ACCEPTANCE LIMITS: SHAFT ______ µm P-P
CASE ______ mm/s
○ INCLUDE MODEL DATA IN LATERAL ANALYSIS (6.16.2.20)
ROTATION, VIEWED FROM DRIVE END ☐ CW ☐ CCW

MATERIALS OF CONSTRUCTION (6.20)

☐ ROTOR BLADES ______
☐ STATOR VANES ______
☐ BLADE/VANE COATING ______
☐ SHAFT ______
☐ TURBINE:

TURBINE STAGE	NOZZLES	BLADES	DISKS or SHROUDS

BALANCING:
○ RESIDUAL UNBALANCE CHECK (6.16.5.2.5)
○ HS BALANCING (6.16.5.3.1)
○ LS RESIDUAL UNBALANCE CHECK AFTER HS BALANCE(6.16.5.3.15)
HIGH-SPEED BALANCING ACCEPTANCE CRITERIA (6.16.5.3.2)
○ GRADE 2.5 ○ ISO 11342 ○ 1.0 mm/s
○ EXTRA VIBRATION PROBES DURING TESTING (6.16.5.3.7)

ROLLING ELEMENT BEARINGS AND BEARING HOUSINGS (6.17.2)

RADIAL BEARINGS		DE	NDE
		BRG No:	BRG No:
☐ TYPE			
☐ MANUFACTURER			
☐ SIZE	mm		
☐ RATED SHAFT SPEED	RPM		
☐ RADIAL LOAD	N		
☐ BEARING 'C' RATING	N		
☐ L-10 BEARING LIFE	hr		
☐ INNER / OUTER RACE MAT'L			
☐ ROLLING ELEMENT MAT'L			
☐ CAGE MATERIAL			

☐ BEARING SPAN ______ mm

RADIAL / THRUST		RADIAL	THRUST
		BRG No:	BRG No:
☐ TYPE			
☐ MANUFACTURER			
☐ SIZE	mm		
☐ RATED SHAFT SPEED	RPM		
☐ RADIAL/THRUST LOAD	N		
☐ BEARING 'C' RATING	N		
☐ L-10 BEARING LIFE	hr		
☐ INNER / OUTER RACE MAT'L			
☐ ROLLING ELEMENT MAT'L			
☐ CAGE MATERIAL			

HYDRODYNAMIC BEARINGS AND BEARING HOUSINGS (6.17.3, 6.17.5, 6.18)

RADIAL		DE	NDE
		BRG No.	BRG No.
☐ TYPE			
☐ MANUFACTURER			
☐ SHAFT DIAMETER	mm		
☐ BEARING LENGTH	mm		
☐ AREA,	mm^2		
☐ UNIT LOAD (ACT/ALLOW	N/mm^2		
☐ BASE MATERIAL			
☐ BABBITT THICKNESS	mm		
☐ NO. PADS			
☐ LOAD: BETWEEN/ON PAD			
☐ PIVOT: CENTER/OFFSET	%		

☐ BEARING SPAN ______ mm
☐ DAMPER BEARING
○ BABBITT TO BACKING ULTRASONIC INSPECTIONS (6.17.3.6)

THRUST		ACTIVE	INACTIVE
		DE/NDE	DE/NDE
☐ TYPE			
☐ MANUFACTURER			
☐ SHAFT DIAMETER	mm		
☐ BEARING SIZE	mm		
☐ AREA	mm^2		
☐ UNIT LOAD (ACT/ALLOW	N/mm^2		
☐ BASE MATERIAL			
☐ BABBITT THICKNESS	mm		
☐ NO. PADS			
☐ PIVOT: CENTER/OFFSET	%		

LUBRICATION: ☐ FLOODED ☐ DIRECTED
THRUST COLLAR: ☐ INTEGRAL ☐ REPLACEABLE
○ BABBITT TO BACKING ULTRSONIC INSPECTIONS (6.17.5.11)

REMARKS:

COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
SI UNITS

JOB NO. ______ ITEM NO. ______
REVISION ______ DATE ______
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REV

☐ **CONSTRUCTION FEATURES - ROTOR No. 1 DESCRIPTION:**

BEARING TEMPERATURE SENSORS (7.5.9.3)

○ USE ATTACHED API 670 DATASHEETS INSTEAD OF THIS DATA SHEET
☐ THERMOCOUPLE TYPE ______
☐ RTD MATERIAL ______ RESISTANCE ______ Ω

SENSOR LOCATION-JOURNAL BEARING:
☐ NUMBER ____ EA PD ____ EVERY OTH PAD ____ PER BRG
OTHER ______
SENSOR LOCATION-THRUST BEARING
☐ NO. (ACT) ____ EA PD ____ EVERY OTH PAD ____ PER BRG
OTHER ______
NO.(INACT) ____ EA PD ____ EVERY OTH PAD ____ PER BRG
OTHER ______
○ MONITOR SUPPLIED, INSTALLED AND CALIBRATED (7.5.9.3.4)
○ MONITOR SUPPLIED BY ______
○ LOCATION ______
○ MFR ______ ○ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ °C
☐ SHUTDOWN SET POINT ______ °C ☐ TIME DELAY ______ sec

CASING AND ROLLING ELEMENT VIBRATION TRANSDUCERS (7.5.9.6.2)

○ SEE ATTACHED API-670 DATASHEETS
○ MFR ______ ○ MODEL ______
○ LOCATION ______ ○ NUMBER ______
○ MONITOR SUPPLIED BY ______
○ LOCATION ______
○ MFR ______ ○ MODEL ______
☐ SCALE RGE ______ ☐ ALARM SET POINT ______ mm/s
☐ SHUTDOWN SET POINT ______ mm/s ☐ TIME DELAY ______ sec

REMARKS:

PROXIMITY PROBES

RADIAL SHAFT VIBRATION PROBES (7.5.9.6.1)

○ SEE ATTACHED API-670 DATASHEETS
○ TYPE ______ ○ MODEL ______
○ MFR ______
○ NO. AT EACH SHAFT BRG ______ TOTAL NO. ______
○ OSCILLATOR-DEMODULATOR SUPPLIED BY ______
○ MFR ______ ○ MODEL ______
○ MONITOR SUPPLIED BY ______
○ LOCATION ______
○ MFR ______ ○ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ µm
☐ SHUTDOWN SET POINT ______ µm ☐ TIME DELAY ______ seconds

AXIAL POSITION PROBES (7.5.9.6.1)

○ SEE ATTACHED API-670 DATASHEETS
○ TYPE ______ ○ MODEL ______
○ MFR ______ ○ NUMBER ______
○ OSCILLATOR-DEMODULATOR SUPPLIED BY ______
○ MFR ______ ○ MODEL ______
○ MONITOR SUPPLIED BY ______
○ LOCATION ______
○ MFR ______ ○ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ µm
☐ SHUTDOWN SET POINT ______ µm ☐ TIME DELAY ______ sec

REMARKS:

COMBUSTION GAS TURBINE (API 616-6th)	JOB NO. ____ ITEM NO. ____	REV
DATASHEET SI UNITS	REVISION ____ DATE ____ PAGE 7 OF ____ BY ____	

CONSTRUCTION FEATURES - ROTOR No. 2 DESCRIPTION:

☐ SPEEDS: 100 % SPEED ____ RPM
☐ MAX. CONT. ____ RPM ☐ TRIP ____ RPM
☐ LATERAL CRITICAL SPEEDS (DAMPED)(6.16.2.1)

FIRST CRITICAL		RPM		MODE
SECOND CRITICAL		RPM		MODE
THIRD CRITICAL		RPM		MODE
FOURTH CRITICAL		RPM		MODE

☐ PROTOTYPE OR MODIFIED ROTOR SUPPORT (6.16.2.21)
○ TRAIN LATERAL ANALYSIS (6.16.2.8)
○ TRAIN TORSIONAL ANALYSIS (6.16.4.2) TORS SF (6.16.4.8) ____
☐ TORSIONAL CRITICAL SPEEDS:

FIRST CRITICAL		RPM
SECOND CRITICAL		RPM
THIRD CRITICAL		RPM
FOURTH CRITICAL		RPM

○ PURCHASER REVIEW OF CAMPBELL/GOODMAN DIAGRAM (6.14.3.4.6)
VIBRATION: (6.16.6.2) (6.16.6.3)
☐ ACCEPTANCE LIMITS: SHAFT ____ μm P-P
CASE ____ mm/s
○ INCLUDE MODEL DATA IN LATERAL ANALYSIS (6.16.2.20)
ROTATION, VIEWED FROM DRIVE END ☐ CW ☐ CCW

MATERIALS OF CONSTRUCTION (6.20)

☐ ROTOR BLADES ____
☐ STATOR VANES ____
☐ BLADE/VANE COATING ____
☐ SHAFT ____
☐ TURBINE:

TURBINE STAGE	NOZZLES	BLADES	DISKS or SHROUDS

BALANCING:
○ RESIDUAL UNBALANCE CHECK (6.16.5.2.5)
○ HS BALANCING (6.16.5.3.1)
○ LS RESIDUAL UNBALANCE CHECK AFTER HS BALANCE(6.16.5.3.15)
HIGH-SPEED BALANCING ACCEPTANCE CRITERIA (6.16.5.3.2)
○ GRADE 2.5 ○ ISO 11342 ○ 1.0 mm/s
○ EXTRA VIBRATION PROBES DURING TESTING (6.16.5.3.7)

ROLLING ELEMENT BEARINGS AND BEARING HOUSINGS (6.17.2, 6.18)

RADIAL BEARINGS		DE	NDE	RADIAL / THRUST		RADIAL	THRUST
		BRG No:	BRG No:			BRG No:	BRG No:
☐ TYPE				☐ TYPE			
☐ MANUFACTURER				☐ MANUFACTURER			
☐ SIZE	mm			☐ SIZE	mm		
☐ RATED SHAFT SPEED	RPM			☐ RATED SHAFT SPEED	RPM		
☐ RADIAL LOAD	N			☐ RADIAL/THRUST LOAD	N		
☐ BEARING 'C' RATING	N			☐ BEARING 'C' RATING	N		
☐ L-10 BEARING LIFE	hr			☐ L-10 BEARING LIFE	hr		
☐ INNER / OUTER RACE MAT'L				☐ INNER / OUTER RACE MAT'L			
☐ ROLLING ELEMENT MAT'L				☐ ROLLING ELEMENT MAT'L			
☐ CAGE MATERIAL				☐ CAGE MATERIAL			
☐ BEARING SPAN			____ mm				

HYDRODYNAMIC BEARINGS AND BEARING HOUSINGS (6.17.3, 6.17.5, 6.18)

RADIAL		DE	NDE	THRUST		ACTIVE	INACTIVE
		BRG No.	BRG No.			DE/NDE	DE/NDE
☐ TYPE				☐ TYPE			
☐ MANUFACTURER				☐ MANUFACTURER			
☐ SHAFT DIAMETER	mm			☐ SHAFT DIAMETER	mm		
☐ BEARING LENGTH	mm			☐ BEARING SIZE	mm		
☐ AREA,	mm^2			☐ AREA	mm^2		
☐ UNIT LOAD (ACT/ALLOW	N/mm^2			☐ UNIT LOAD (ACT/ALLOW	N/mm^2		
☐ BASE MATERIAL				☐ BASE MATERIAL			
☐ BABBITT THICKNESS	mm			☐ BABBITT THICKNESS	mm		
☐ NO. PADS				☐ NO. PADS			
☐ LOAD: BETWEEN/ON PAD				☐ PIVOT: CENTER/OFFSET	%		
☐ PIVOT: CENTER/OFFSET	%						

LUBRICATION: ☐ FLOODED ☐ DIRECTED
THRUST COLLAR: ☐ INTEGRAL ☐ REPLACEABLE

☐ BEARING SPAN ____ mm
☐ DAMPER BEARING
○ BABBITT TO BACKING ULTRASONIC INSPECTIONS (6.17.3.6)
○ BABBITT TO BACKING ULTRSONIC INSPECTIONS (6.17.5.11)

REMARKS:

COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
SI UNITS

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CONSTRUCTION FEATURES - ROTOR No. 2 DESCRIPTION:

BEARING TEMPERATURE SENSORS (7.5.9.3)

USE ATTACHED API 670 DATASHEETS INSTEAD OF THIS DATA SHEET
THERMOCOUPLE TYPE
RTD MATERIAL RESISTANCE Ω

SENSOR LOCATION-JOURNAL BEARING:
NUMBER EA PD EVERY OTH PAD PER BRG
OTHER
SENSOR LOCATION-THRUST BEARING
NO. (ACT) EA PD EVERY OTH PAD PER BRG
OTHER
NO.(INACT) EA PD EVERY OTH PAD PER BRG
OTHER
MONITOR SUPPLIED, INSTALLED AND CALIBRATED (7.5.9.3.4)
MONITOR SUPPLIED BY
LOCATION
MFR MODEL
SCALE RANGE ALARM SET POINT °C
SHUTDOWN SET POINT °C TIME DELAY sec

CASING AND ROLLING ELEMENT VIBRATION TRANSDUCERS (7.5.9.6.2)

SEE ATTACHED API-670 DATASHEETS
MFR MODEL
LOCATION NUMBER
MONITOR SUPPLIED BY
LOCATION
MFR MODEL
SCALE RGE ALARM SET POINT mm/s
SHUTDOWN SET POINT mm/s TIME DELAY sec

REMARKS:

PROXIMITY PROBES

RADIAL SHAFT VIBRATION PROBES (7.5.9.6.1)

SEE ATTACHED API-670 DATASHEETS
TYPE MODEL
MFR
NO. AT EACH SHAFT BRG TOTAL NO.
OSCILLATOR-DEMODULATOR SUPPLIED BY
MFR MODEL
MONITOR SUPPLIED BY
LOCATION
MFR MODEL
SCALE RANGE ALARM SET POINT μm
SHUTDOWN SET POINT μm TIME DELAY seconds

AXIAL POSITION PROBES (7.5.9.6.1)

SEE ATTACHED API-670 DATASHEETS
TYPE MODEL
MFR NUMBER
OSCILLATOR-DEMODULATOR SUPPLIED BY
MFR MODEL
MONITOR SUPPLIED BY
LOCATION
MFR MODEL
SCALE RANGE ALARM SET POINT μm
SHUTDOWN SET POINT μm TIME DELAY sec

REMARKS:

COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
SI UNITS

JOB NO.		ITEM NO.	
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CONSTRUCTION FEATURES - ROTOR No. 3 DESCRIPTION:

☐ SPEEDS: 100 % SPEED ______ RPM
☐ MAX. CONT. ______ RPM ☐ TRIP ______ RPM
☐ LATERAL CRITICAL SPEEDS (DAMPED)(6.16.2.1)
FIRST CRITICAL ______ RPM ______ MODE
SECOND CRITICAL ______ RPM ______ MODE
THIRD CRITICAL ______ RPM ______ MODE
FOURTH CRITICAL ______ RPM ______ MODE
☐ PROTOTYPE OR MODIFIED ROTOR SUPPORT (6.16.2.21)
○ TRAIN LATERAL ANALYSIS (6.16.2.8)
○ TRAIN TORSIONAL ANALYSIS (6.16.4.2) TORS SF (6.16.4.8) ______
☐ TORSIONAL CRITICAL SPEEDS:
FIRST CRITICAL ______ RPM
SECOND CRITICAL ______ RPM
THIRD CRITICAL ______ RPM
FOURTH CRITICAL ______ RPM
○ PURCHASER REVIEW OF CAMPBELL/GOODMAN DIAGRAM (6.14.3.4.6)
VIBRATION: (6.16.6.2) (6.16.6.3)
☐ ACCEPTANCE LIMITS: SHAFT ______ µm P-P
CASE ______ mm/s
○ INCLUDE MODEL DATA IN LATERAL ANALYSIS (6.16.2.20)
ROTATION, VIEWED FROM DRIVE END ☐ CW ☐ CCW

MATERIALS OF CONSTRUCTION (6.20)

☐ ROTOR BLADES ______
☐ STATOR VANES ______
☐ BLADE/VANE COATING ______
☐ SHAFT ______
☐ TURBINE:

TURBINE STAGE	NOZZLES	BLADES	DISKS or SHROUDS

BALANCING:
○ RESIDUAL UNBALANCE CHECK (6.16.5.2.5)
○ HS BALANCING (6.16.5.3.1)
○ LS RESIDUAL UNBALANCE CHECK AFTER HS BALANCE(6.16.5.3.15)
HIGH-SPEED BALANCING ACCEPTANCE CRITERIA (6.16.5.3.2)
○ GRADE 2.5 ○ ISO 11342 ○ 1.0 mm/s
○ EXTRA VIBRATION PROBES DURING TESTING (6.16.5.3.7)

ROLLING ELEMENT BEARINGS AND BEARING HOUSINGS (6.17.2)

RADIAL BEARINGS		DE	NDE
		BRG No:	BRG No:
☐ TYPE			
☐ MANUFACTURER			
☐ SIZE	mm		
☐ RATED SHAFT SPEED	RPM		
☐ RADIAL LOAD	N		
☐ BEARING 'C' RATING	N		
☐ L-10 BEARING LIFE	hr		
☐ INNER / OUTER RACE MAT'L			
☐ ROLLING ELEMENT MAT'L			
☐ CAGE MATERIAL			

☐ BEARING SPAN ______ mm

RADIAL / THRUST		RADIAL	THRUST
		BRG No:	BRG No:
☐ TYPE			
☐ MANUFACTURER			
☐ SIZE	mm		
☐ RATED SHAFT SPEED	RPM		
☐ RADIAL/THRUST LOAD	N		
☐ BEARING 'C' RATING	N		
☐ L-10 BEARING LIFE	hr		
☐ INNER / OUTER RACE MAT'L			
☐ ROLLING ELEMENT MAT'L			
☐ CAGE MATERIAL			

HYDRODYNAMIC BEARINGS AND BEARING HOUSINGS (6.17.3, 6.17.5, 6.18)

RADIAL		DE	NDE
		BRG No.	BRG No.
☐ TYPE			
☐ MANUFACTURER			
☐ SHAFT DIAMETER	mm		
☐ BEARING LENGTH	mm		
☐ AREA,	mm^2		
☐ UNIT LOAD (ACT/ALLOW)	N/mm^2		
☐ BASE MATERIAL			
☐ BABBITT THICKNESS	mm		
☐ NO. PADS			
☐ LOAD: BETWEEN/ON PAD			
☐ PIVOT: CENTER/OFFSET	%		

☐ BEARING SPAN ______ mm
☐ DAMPER BEARING
○ BABBITT TO BACKING ULTRASONIC INSPECTIONS (6.17.3.6)

THRUST		ACTIVE	INACTIVE
		DE/NDE	DE/NDE
☐ TYPE			
☐ MANUFACTURER			
☐ SHAFT DIAMETER	mm		
☐ BEARING SIZE	mm		
☐ AREA	mm^2		
☐ UNIT LOAD (ACT/ALLOW)	N/mm^2		
☐ BASE MATERIAL			
☐ BABBITT THICKNESS	mm		
☐ NO. PADS			
☐ PIVOT: CENTER/OFFSET	%		

LUBRICATION: ☐ FLOODED ☐ DIRECTED
THRUST COLLAR: ☐ INTEGRAL ☐ REPLACEABLE
○ BABBITT TO BACKING ULTRASONIC INSPECTIONS (6.17.5.11)

REMARKS:

COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
SI UNITS

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☐ CONSTRUCTION FEATURES - ROTOR No. 3 DESCRIPTION:

BEARING TEMPERATURE SENSORS (7.5.9.3)

○ USE ATTACHED API 670 DATASHEETS INSTEAD OF THIS DATASHEET
☐ THERMOCOUPLE TYPE ______
☐ RTD MATERIAL ______ RESISTANCE ______ Ω

SENSOR LOCATION-JOURNAL BEARING:
☐ NUMBER ____ EA PD ____ EVERY OTH PAD ____ PER BRG
OTHER ______
SENSOR LOCATION-THRUST BEARING
☐ NO. (ACT) ____ EA PD ____ EVERY OTH PAD ____ PER BRG
OTHER ______
NO.(INACT) ____ EA PD ____ EVERY OTH PAD ____ PER BRG
OTHER ______
○ MONITOR SUPPLIED, INSTALLED AND CALIBRATED (7.5.9.3.4)
◙ MONITOR SUPPLIED BY ______
○ LOCATION ______
◙ MFR ______ ◙ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ °C
☐ SHUTDOWN SET POINT ______ °C ☐ TIME DELAY ______ sec

CASING AND ROLLING ELEMENT VIBRATION TRANSDUCERS (7.5.9.6.2)

○ SEE ATTACHED API-670 DATASHEETS
◙ MFR ______ ◙ MODEL ______
○ LOCATION ______ ◙ NUMBER ______
◙ MONITOR SUPPLIED BY ______
○ LOCATION ______
◙ MFR ______ ◙ MODEL ______
☐ SCALE RGE ______ ☐ ALARM SET POINT ______ mm/s
☐ SHUTDOWN SET POINT ______ mm/s ☐ TIME DELAY ______ sec

REMARKS:

PROXIMITY PROBES

RADIAL SHAFT VIBRATION PROBES (7.5.9.6.1)

○ SEE ATTACHED API-670 DATASHEETS
◙ TYPE ______ ◙ MODEL ______
◙ MFR ______
◙ NO. AT EACH SHAFT BRG ______ TOTAL NO. ______
◙ OSCILLATOR-DEMODULATOR SUPPLIED BY ______
◙ MFR ______ ◙ MODEL ______
◙ MONITOR SUPPLIED BY ______
◙ LOCATION ______
◙ MFR ______ ◙ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ μm
☐ SHUTDOWN SET POINT ______ μm ☐ TIME DELAY ______ seconds

AXIAL POSITION PROBES (7.5.9.6.1)

○ SEE ATTACHED API-670 DATASHEETS
◙ TYPE ______ ◙ MODEL ______
◙ MFR ______ ◙ NUMBER ______
◙ OSCILLATOR-DEMODULATOR SUPPLIED BY ______
◙ MFR ______ ◙ MODEL ______
◙ MONITOR SUPPLIED BY ______
○ LOCATION ______
◙ MFR ______ ◙ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ μm
☐ SHUTDOWN SET POINT ______ μm ☐ TIME DELAY ______ sec

REMARKS:

COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
SI UNITS

JOB NO. ______ ITEM NO. ______
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UTILITIES (9.2.3.2.i)

☐ **UTILITY CONDITIONS:**

STEAM:	**AUXILIARY DRIVERS**		**HEATING**	
INLET MIN	MPag	°C	MPag	°C
NORM	MPag	°C	MPag	°C
MAX	MPag	°C	MPag	°C
EXHST MIN.	MPag	°C	MPag	°C
NORM	MPag	°C	MPag	°C
MAX	MPag	°C	MPag	°C
	STARTING		**INJECTION**	
INLET MIN	MPag	°C	MPag	°C
NORM	MPag	°C	MPag	°C
MAX	MPag	°C	MPag	°C
EXHST MIN.	MPag	°C		
NORM	MPag	°C		
MAX	MPag	°C		

○ INLET AIR EVAPORATIVE COOLING / FOGGING WATER:
INLET TEMPERATURE ______ °C
DESIGN TEMPERATURE ______ °C
NORM PRESS ______ MPag
DESIGN PRESS ______ MPag
WATER QUALITY ______

○ COOLING WATER:
INLET TEMPERATURE ______ °C MAX RETURN ______ °C
DESIGN TEMPERATURE ______ °C
NORM PRESS ______ MPag MIN RETURN ______ MPag
DESIGN PRESS ______ MPag MAX ALLOW ΔP ______ MPa D
WATER SOURCE ______

○ INLET AIR CHILLING (IAC) WATER:
INLET TEMPERATURE ______ °C MAX RETURN ______ °C
DESIGN TEMPERATURE ______ °C
NORM PRESS ______ MPag MIN RETURN ______ MPag
DESIGN PRESS ______ MPag MAX ALLOW Δ P ______ MPag

☐ **TOTAL UTILITY CONSUMPTION:**
IAH / COOLING / IAC WATER ______ / ______ / ______ m^3/hr
STEAM LEVEL ______ MPag ______ MPag ______ MPag
STEAM, NORMAL ______ kg/h ______ kg/h ______ kg/h
STEAM, MAX ______ kg/h ______ kg/h ______ kg/h
INSTRUMENT AIR ______ Nm^3/h
NITROGEN ______ Nm^3/h
MOTORS (AUXILIARIES) ______ kW
BATTERY CHARGERS ______ kW
HEATERS ______ kW

GAS TURBINE AIR EXTRACTION (7.7.2.8.1, 7.7.2.9.4.5)
○ FLOW ______ Nm^3/h PRESS ______ MPag TEMP ______ °C
☐ MAXIMUM PRESSURE AVAILABLE AT MINIMUM SPEED: ______ MPag
☐ MINIMUM SPEED: ______ RPM
☐ DISCHARGE TEMPERATURE ______ °C
☐ COMPRESSOR EXTRACTION STAGE NUMBER: ______
○ BLEED VALVE DESIGN APPROVAL REQUIRED (7.7.2.8.7)

○ INSTRUMENT AIR PRESSURE DESIGN, MPag ______
MAX ______ NORMAL ______ MIN ______
○ NITROGEN PRESSURE DESIGN ______ MPag
MAX ______ NORMAL ______ MIN ______

ELECTRICITY: (7.5.8.1)

	MOTORS	HEATING	CONTROL	SHUTDOWN
VOLTAGE				
HERTZ				
PHASE				

☐ ALARM IN LIEU OF PILOT LIGHTS (7.5.8.3.2)

REMARKS:

PURCHASER CONNECTIONS (6.13) (7.6)

MAIN CONNECTION	○ WELDING DESIGN APPROVAL (6.24.6.4)	☐ SIZE	☐ FACING AND RATING	☐ INLET & EXHAUST ORIENTATION (7.7.1.2)	☐ FLANGED OR STUDDED	☐ MATING FLG AND GASKET BY VENDOR (6,13,6)	☐ GAS VELOCITY m/s

COMBUSTION GAS TURBINE (API 616-6th)	JOB NO.		ITEM NO.		REV
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INSTRUMENTATION, LUBRICATION & HARDWARE

OUTDOOR CONTROLS AND INSTRUMENTATION CODE (7.5.1.2.1, 7.5.8.18)
○ IEC 60529 IP66 ○ NEMA 250 4X ○ OTHER ______
INSTRUMENTATION MOUNTING (7.5.1.2) ○ INDOOR ○ OUTDOOR

○ REDUNDANT CONTROL SYSTEM EQUIPMENT (7.5.2.15)
○ REDUNDANT SENSORS AND INPUTS PER API 614 (7.5.2.16)
○ UPS DURATION (7.5.2.18) ______ MINUTES
CONTROL SYSTEM POWER (7.5.6.5) ○ AC ○ DC
○ DCS LINK REQD (7.5.2.19)
DCS DATA COMMUNICATION FREQUENCY (7.5.2.20) ______ ms
○ SIL RATING (7.5.2.24) ______
○ SPECIAL MOUNTING ARRANGEMENTS REQD (7.5.5.13)
○ SHUTDOWN SENSING DEVICE ISOLATION REQ'D (7.5.5.29)
○ CONFORMAL COATINGS ON PRINTED CIRCUIT BOARDS (7.5.6.11)
○ EVENT RECORDER REQUIRED (7.5.5.27)
☐ GAUGE BOARD LOCATION
○ SEPARATE TACHOMETER DISPLAY (7.5.9.1.2)
SPEED SENSOR (7.5.9.1.3) ○ ACTIVE ○ PASSIVE
◙ TACHOMETER MANUFACTURER ______
○ GLYCERINE-FILLED GAUGES (7.5.9.4.2)
CONTROL WIRING (7.5.8.21.8): ○ ARMORED ○ METAL CONDUIT
CONTROL SYSTEM DETAILS:
MACHINERY PROTECTION ARRANGEMENTS (7.5.5.1)
☐ DISTRIBUTED ☐ INTEGRATED
○ SWITCHES ALLOWED FOR ALARM, TRIP & SHUTDOWN (7.5.5.14.2)
○ REQ'D COMMUNICATION PROTOCOL (7.5.7.5) ______
○ FIRST-OUT ANNUNCIATOR REQ'D (7.5.5.23)

LOAD CONTROL - GOVERNOR (7.5.3)

◙ MAKE ______ ◙ MODEL ______
◙ ISOCHRONOUS ◙ DROOP
◙ REMOTE SHUTDOWN SIGNAL TYPE: ______
☐ CONTROL SIGNAL RANGE (7.5.3.4) mA

CONTROL SYSTEMS

NON-LOGIC SOLVER CONTROL TYPES (7.5.2.11):
☐ MECH | ○ PNEU ☐ HYDRAULIC ☐ ELECTRIC
☐ MICROPROCESSOR BASED ☐ ELECTRONIC
CONTROL CONSOLES (7.5.6.2)
○ OFF-SKID INDOOR ○ OFF-SKID OUTDOOR ○ ON-SKID (7.5.6.3)
○ OFF-SKID CONTROL PANEL CABLE LENGTH (7.5.6.2 b) ______ m
ADDITIONAL HMI QUANTITY (7.5.7.4)
○ PORTABLE ______ ○ DESKTOP ______ ○ PANEL ______
○ HMI START-UP GRAPHICS REQ'D (7.5.7.6.3)
STARTING SYSTEM (7.5.2.5)
○ MANUAL ○ SEMI-AUTOMATIC ○ AUTOMATIC
☐ PURGE PERIOD (7.5.4, 7.5.4.2) ______ MINUTES

REMARKS:

LUBRICATION SYSTEMS
○ API 614 (6.19.6)
MINERAL LUBE SYSTEM (6.19.5)
◙ OIL VISCOSITY
◙ LUBE SPECIFICATION ______
COMMON TO ◙ GAS GENERATOR or SINGLE SHAFT GT
◙ FREE POWER TURBINE ◙ LOAD GEAR
◙ DRIVEN EQUIPMENT ◙ AUXILIARIES
SYNTHETIC LUBE OIL SYSTEM (6.19.3, 6.19.5)
◙ USE SYNTHETIC LUBE (6.19.3, 6.19.5)
◙ OIL VISCOSITY
◙ LUBE SPECIFICATION ______
COMMON TO ◙ GAS GENERATOR or SINGLE SHAFT GT
◙ FREE POWER TURBINE ◙ LOAD GEAR
◙ DRIVEN EQUIPMENT ◙ AUXILIARIES
○ REAL-TIME OIL DEBRIS DETECTION AND DISPLAY (7.5.9.7.2)

☐ **OIL REQUIREMENTS**

	FLOW (m^3/h)	PRESSURE MPag	HEAT LOAD (kW)
GAS GENERATOR			
POWER TURBINE			
HYD START SYSTEM			

MINERAL OIL RESERVOIR CAPACITY ______ liters
SYNTHETIC OIL RESERVOIR CAPACITY ______ liters
HYDRAULIC OIL RESERVOIR CAPACITY ______ liters
HYDRAULIC OIL SPECIFICATION

WEIGHTS & DIMENSIONS

	☐ INSTALLED (kg)	☐ SHIPPING (kg)	☐ DIMENSIONS LxWxH (m)
GAS GENERATOR			
POWER TURBINE			
GT ENCLOSURE			
INLET FILTER HOUSE			
INLET AIR DUCTING			
VENT DUCTING			
EXHAUST DUCTING			
MIN OIL CONSOLE			
SYN OIL CONSOLE			
MIN OIL SEPARATOR			
SYN OIL SEPARATOR			
MIN OIL AIR COOLER			
SYN OIL AIR COOLER			
HYD START SKID			
CO_2 CYLINDER SKID			
WATER WASH SKID			
TOTAL PACKAGE WT			
MAX ERECTION WT		ITEM	
MAX MAINT WT		ITEM	

○ MEASURE GT PACKAGE WEIGHT AND CENTER OF GRAVITY (8.4.3.9)

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INSTRUMENTATION & HARDWARE

	INSTRUMENT TYPE		INSTRUMENT LOCATION			TRANS-MITTERS FURNISHED BY		CONTROL ROOM RECEIVERS FURN BY		
DESCRIPTION (7.5.5.13.1)	INDICATING	RECORDING	LOCAL	LOCAL PANEL	CONTROL ROOM	VENDOR	OTHERS	VENDOR	OTHERS	
SINGLE OR MULTI-SHAFT GAS TURBINE										
TACHOMETER(S)	○	○	○	○	○	○	○	○	○	
AIR INLET SYSTEM ΔP	○	○	○	○	○	○	○	○	○	
COMPRESSOR DISCHARGE PRESSURE	○	○	○	○	○	○	○	○	○	
FUEL FILTER DP	○	○	○	○	○	○	○	○	○	
FUEL SUPPLY PRESSURE	○	○	○	○	○	○	○	○	○	
STARTING GAS SUPPLY PRESSURE	○	○	○	○	○	○	○	○	○	
STARTING GAS EXHAUST PRESSURE	○	○	○	○	○	○	○	○	○	
TEMP COMBUSTOR MEASUREMENT	○	○	○	○	○	○	○	○	○	
TEMP GAS TURB CONTROL PANEL	○	○	○	○	○	○	○	○	○	
INLET AIR TEMPERATURE	○	○	○	○	○	○	○	○	○	
TEMPERATURE, GG COMPRESSOR DISCHARGE	○	○	○	○	○	○	○	○	○	
TEMPERATURE, RADIAL BEARING	○	○	○	○	○	○	○	○	○	
TEMPERATURE, THRUST BEARING	○	○	○	○	○	○	○	○	○	
TEMPERATURE, FUEL MANIFOLD	○	○	○	○	○	○	○	○	○	
TEMPERATURE, LUBE OIL RESERVOIR	○	○	○	○	○	○	○	○	○	
FIRED HOUR METER										
A) NUMBER STARTS COUNTER	○	○	○	○	○	○	○	○	○	
B) START SEQUENCE TIMER	○	○	○	○	○	○	○	○	○	
LUBE OIL INLET PRESSURE	○	○	○	○	○	○	○	○	○	
LUBE OIL INLET TEMPERATURE	○	○	○	○	○	○	○	○	○	
LUBE OIL RESERVOIR LEVEL	○	○	○	○	○	○	○	○	○	
LUBE OIL PUMP PRESSURE INDICATORS (NO.)	○	○	○	○	○	○	○	○	○	
LUBE OIL COOLER OIL INLET TEMPERATURE	○	○	○	○	○	○	○	○	○	
LUBE OIL COOLER OIL OUTLET TEMPERATURE	○	○	○	○	○	○	○	○	○	
LUBE OIL COOLER COOLANT INLET TEMPERATURE	○	○	○	○	○	○	○	○	○	
LUBE OIL COOLER COOLANT OUTLET TEMPERATURE	○	○	○	○	○	○	○	○	○	
LUBE OIL FILTER DP	○	○	○	○	○	○	○	○	○	
LUBE OIL PRESSURE EACH LEVEL (NO.)	○	○	○	○	○	○	○	○	○	
CONTROL OIL PRESSURE	○	○	○	○	○	○	○	○	○	
SITE FLOW INDICATOR EACH DRAIN (NO.)	○	○	○	○	○	○	○	○	○	
INLET GUIDE VANE POSITION INDICATOR	○	○	○	○	○	○	○	○	○	
EXHAUST DUCT DIFFERENTIAL PRESSURE INDICATOR	○	○	○	○	○	○	○	○	○	
TEMPERATURE, EXHAUST	○	○	○	○	○	○	○	○	○	
ENCLOSURE COOLING AIR EXHAUST TEMPERATURE	○	○	○	○	○	○	○	○	○	
POWER TURBINE										
TACHOMETER(S) (NO.)	○	○	○	○	○	○	○	○	○	
TEMPERATURE, EXHAUST	○	○	○	○	○	○	○	○	○	
TEMPERATURE, RADIAL BEARING	○	○	○	○	○	○	○	○	○	
TEMPERATURE, THRUST BEARING	○	○	○	○	○	○	○	○	○	
SITE FLOW INDICATOR EACH DRAIN (NO.)	○	○	○	○	○	○	○	○	○	
LUBE OIL INLET PRESSURE	○	○	○	○	○	○	○	○	○	
LUBE OIL INLET TEMPERATURE	○	○	○	○	○	○	○	○	○	

REMARKS:

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ALARMS AND SHUTDOWNS (7.5.5.13, 7.5.5.13.1)

	DESCRIPTION	APPLIES TO: SINGLE SHAFT OR GG	APPLIES TO: FREE PT	ANNUNCIATED IN FIRST OUT PANEL SUPPLIED BY VENDOR (7.5.5.23): ALARM	ANNUNCIATED IN FIRST OUT PANEL SUPPLIED BY VENDOR (7.5.5.23): SHUT-DOWN	SENSING DEVICES TO BE FURNISHED BY: VENDOR	SENSING DEVICES TO BE FURNISHED BY: OTHERS	INDICATING LIGHT ONLY
4	○ SEE ATTACHED API 614 DATA SHEET (7.5.5.14)							
6	RADIAL SHAFT VIBRATION	○	○	○	○	○	○	□
7	AXIAL THRUST POSITION	○	○	○	○	○	○	□
8	OVERSPEED	○	○	○	○	○	○	□
9	CASING VIBRATION	○	○	○	○	○	○	□
10	HIGH THRUST BEARING TEMPERATURE	○	○	○	○	○	○	□
11	HIGH RADIAL BEARING TEMPERATURE	○	○	○	○	○	○	□
12	LOW FUEL SUPPLY PRESSURE	○	○	○	○	○	○	□
13	HIGH FUEL FILTER Δ P	○	○	○	○	○	○	□
14	GAS TURBINE TEMPERATURE SPREAD HIGH	○	○	○	○	○	○	□
15	EXHAUST OVER TEMPERATURE	○	○	○	○	○	○	□
16	FAILURE OF OVER-TEMPERATURE SHUTDOWN DEVICE	○	○	○	○	○	○	□
17	HIGH INLET AIR Δ P EACH FILTER	○	○	○	○	○	○	□
18	COMBUSTOR FLAME-OUT	○	○	○	○	○	○	□
19	CHIP DETECTOR, BEARING	○	○	○	○	○	○	□
20	FAILURE STARTING CLUTCH TO ENGAGE OR DISENGAGE	○	○	○	○	○	○	□
21	LOW OIL PRESSURE	○	○	○	○	○	○	□
22	HIGH LUBE OIL TEMPERATURE	○	○	○	○	○	○	□
23	LOW LUBE OIL RESERVOIR LEVEL	○	○	○	○	○	○	□
24	HIGH LUBE OIL RESERVOIR LEVEL	○	○	○	○	○	○	□
25	HIGH OIL FILTER Δ P	○	○	○	○	○	○	□
26	LUBE OIL SPARE PUMP OPERATING	○	○	○	○	○	○	□
27	LOW CONTROL OIL PRESSURE	○	○	○	○	○	○	□
28	LOW STARTING GAS PRESSURE	○	○	○	○	○	○	□
29	ANTI-ICING SYSTEM - NOT OPERATING	○	○	○	○	○	○	□
30	LOW D.C. VOLTAGE	○	○	○	○	○	○	□
31	EMERGENCY D.C. PUMP OPERATING	○	○	○	○	○	○	□
32	RESERVOIR HEATER "ON"	○	○	○	○	○	○	□
33	IMPLOSION DOOR OPEN	○	○	○	○	○	○	□
34	EXTERNAL PERMISSIVE START SIGNAL	○	○	○	○	○	○	□
35	EXTERNAL SHUTDOWN SIGNAL	○	○	○	○	○	○	□
36	LOSS OF AUXILIARY COOLING AIR	○	○	○	○	○	○	□
37	LAMP TEST PUSH BUTTON	○	○	○	○	○	○	□
38	ENCLOSURE HIGH TEMPERATURE	○	○	○	○	○	○	□
39	CONTROL SIGNAL FAILURE	○	○	○	○	○	○	□
40	CONTROL SYSTEM ACTUATOR FAILURE	○	○	○	○	○	○	□
41	GOVERNOR FAILURE	○	○	○	○	○	○	□
42	ENCLOSURE VENT FAN FAILURE	○	○	○	○	○	○	□
43	SPARE ENCLOSURE VENT FAN OPERATING	○	○	○	○	○	○	□
44	WOBBE METER	○	○	○	○	○	○	□
45	GAS CHROMATOGRAPH	○	○	○	○	○	○	□
46	EXHAUST GAS ANALYZER	○	○	○	○	○	○	□

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COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
SI UNITS

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ACCESSORIES SUPPLIED BY MANUFACTURER OR PACKAGER

STARTING AND HELPER DRIVERS (7.1.1.1, 7.1.2.1)

○ STARTER ONLY ○ STARTER/HELPER
TYPE (7.1.2.1) ○ MOTOR: ○ API 541 ○ API 546 ○ IEC 60034-1
○ GAS EXPANDER ○ IC ENGINE ○ HYDRAULIC
☐ STARTER IS CLUTCHED (7.1.1.5)
☐ HELPER RATING (7.1.3.3) ______ kW
☐ STARTER RATING (7.1.3) ______ kW
○ SHAFT TURNING GEAR OR RACHET DEVICE REQUIRED (7.1.4.1)

☐ **MOTOR (STARTER ONLY):**
TYPE ______ RATING ______ MW
MFR ______ MODEL ______
○ REDUCED VOLTAGE STARTING (7.1.2.6) ______ %

☐ **MOTOR (STARTER / HELPER):**
TYPE ______ RATING ______ MW
MFR ______ MODEL ______
○ REDUCED VOLTAGE STARTING (7.1.2.6) ______ %

GAS EXPANDER
○ APPLICABLE SPEC. (7.1.1.4) ______
☐ MFR ______ MODEL ______
☐ RATING ______ MW
☐ TOTAL/START ______ kg ☐ MAX. GAS FLOW ______ kg/h
GAS FOR EXPANDER: ○ AIR ○ NATURAL GAS

	MIN	MAX	NORMAL
☐ INLET PRESSURE MPag			
☐ EXHAUST PRESS MPag			
☐ GAS TEMPERATURE, °C INLET			
☐ GAS TEMPERATURE, °C EXHAUST			
○ MOLECULAR WEIGHT			

SPEED CONTROL ☐ GOVERNOR ☐ PRESSURE REGULATOR

DESIGN DETAILS:	YES	NO
INLET CONTROL VALVE FURNISHED	☐	☐
STAINLESS STEEL PIPING MANIFOLD	☐	☐
CARBON STEEL FLANGES	☐	☐
Y-STRAINER W/BREAKOUT FLANGES	☐	☐
LOW SPEED CAPABILITY (FOR COMPRESSOR CLEANING)	☐	☐

☐ RELIEF VALVE PRESSURE SET POINT ______ MPag
☐ CASING MATERIAL ______
☐ SEAL TYPE ______

INTERNAL COMBUSTION ENGINE
TYPE ○ SPARK IGNITED ○ DIESEL
○ APPLICABLE SPEC. (7.1.1.4) ______
☐ MFR ______ ☐ MODEL ______
☐ SPEED ______ RPM ☐ RATING ______ MW

STEAM TURBINE (REFER TO API DATASHEETS)
○ APPLICABLE SPEC. (7.1.1.4) ______
☐ MFR ______ ☐ MODEL ______
☐ RATING ______ MW ☐ MAX. STEAM FLOW ______ kg/h
☐ TOTAL FLOW / START ______ kg

GEARS
○ LOAD GEAR SUPPLIED BY GAS TURBINE OEM (7.2.1.2)
○ LOAD AND HELPER SEE API 613 GEAR DATASHEETS (7.2.1.1)
○ STARTERS SEE API 677 GEAR DATASHEETS (7.1.1.6)

MOUNTING PLATES (7.3)
TYPE ○ SOLEPLATE ○ BASEPLATE
☐ SHIM PACK THICKNESS ______ mm
SPECIFIED GROUT (7.3.1.1) ○ EPOXY ○ CEMENTITIOUS

BASEPLATE (7.4)
TYPE (7.4.1.1, 7.4.1.12)
○ 3-POINT ○ COLUMN ○ PERIMETER
○ FULL GROUT (7.4.1.20)
BASEPLATE CONTAINS
☐ GAS TURBINE ☐ GEAR ☐ ACCESSORIES ☐ DRIVEN EQUIPMENT
○ PROVIDE LIFTING EQUIPMENT (7.4.1.17)
GRATING REQUIREMENTS (7.4.1.23) ○ SS ○ GRP
○ DESIGN FOR OPTICAL/LASER FIELD LEVELING (7.4.1.11)
○ SUB-SOLEPLATES REQUIRED (7.4.2.1)
○ LESS 25 kg MANWAY DOORS REQ DAVIT (7.7.1.11.2)

ENCLOSURES
○ AUXILIARY EQUIPMENT ENCLOSURE(S) (7.8.4.2)
○ DRIVEN EQUIPMENT ENCLOSURE(S) (7.8.4.3)
ADDITIONAL VENTILATION FANS (7.8.4.19.2)
○ 1X100% ○ 2X100% ○ 3X50%
○ OTHER ______

COUPLINGS AND GUARDS (7.2.2)

COUPLINGS
SEE ATTACHED API 671 DATA SHEETS
○ LESS THAN 4000 RPM COUPLINGS DESIGNED TO ISO 14691 (7.2.2.7):
☐ MFR ______ ☐ TYPE ______
☐ MODEL ______ ☐ GUARD SUPPLIED BY ______
☐ MAXIMUM OUTSIDE DIAMETER ______ mm
☐ HUB WEIGHT ______ kg
☐ SPACER LENGTH ______ mm ☐ SPACER WEIGHT kg ______
○ TORQUE MONITORING SYSTEM (7.2.2.3)

COUPLING GUARDS ______
TYPE: ○ FULLY-ENCLOSED ○ SEMI-OPEN ○ OTHER ______

MAINTENANCE INTERVALS, HOURS / DURATION, HOURS
☐ BORESCOPE INSPECTION ______ / ______
☐ HOT SECTION OVERHAUL ______ / ______
☐ MAJOR OVERHAULS ______ / ______

REMARKS ______

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ACCESSORIES SUPPLIED BY GAS TURBINE MANUFACTURER

ENVIRONMENTAL CONDITIONS (6.6)	**INLET SYSTEM** (7.7.2)
INLET METEOROLOGICAL CONDITIONS (6.6.1, 6.6.6):	☐ INLET HEATING (7.7.2.9.4.1) ☐ FOD SCREEN (7.7.2.1.7)
○ WIND SPEED & DIRECTION ______ km/h	
○ SEE ATTACHED WIND ROSE	☐ INLET PLENUM WINDOW (7.7.1.12)
○ RAINFALL MAX RATE ______ mm/h	○ INLET DUCTWORK INTERFACE POINTS (7.7.1.4.1)
○ SNOWFALL MAX RATE ______ mm/h	______
○ FOG OR MIST CONDITIONS	______
○ ICING CONDITIONS	○ OFFSHORE MIN AIR ENTRANCE HEIGHT (7.7.2.3.20) ______ m
REMARKS ______	☐ SELF-CLEANING (7.7.2.3.21) ○ ISOLATION VALVES (7.7.2.4.3)
______	○ RELATIVE HUMIDITY SENSOR (7.7.2.4.7)
	☐ HIGH VELOCITY INLET SYSTEM
CHEMICAL CONTAMINANTS IN THE AIR (6.6.7): (ppmv)	☐ FINAL ELEMENT FILTER CLASS (7.7.2.3.5) ______
○ SODIUM (Na) ______	☐ ADDITIONAL VANE SEPARATOR (7.7.2.2.4)
○ POTASSIUM (K) ______	☐ FILTER MFR. ______ MODEL ______
○ CALCIUM (Ca) ______	☐ MAINTENANCE INTERVAL ______ MONTHS
○ CHLORIDE (Cl) ______	☐ INLET FILTERS REPLACEABLE DURING OPERATION (7.7.2.6.1)
○ SULPHATE (SO_4) ______	☐ MANOMETER MFR ______ MODEL ______
○ NITRATE (NO_3) ______	RANGE ______ mm H_2O
○ TRACE METALS (V, Pb, Ni, Zn) ______	☐ DUCTING GAUGE / MATERIAL ______ / ______
○ SULPHUR DIOXIDE (SO_2) ______	☐ EXPANSION JOINT MFR ______ TYPE ______
○ AMMONIA (NH_3) ______	☐ EXPANSION JOINT SOUND-ABSORBING MATERIAL PROVISIONS (7.7.1.15)
○ NITROUS OXIDES (NO_X) ______	○ COMBUSTION AND VENT. AIR INTAKE GAS DETECTORS (7.7.2.1.4,7.8.3.13)
○ HYDROCARBONS (VOC) ______	○ FILTER HOUSE LIGHTING ON UPS (7.7.2.3.17.c)
○ HYDROGEN SULFIDE (H_2S) ______	○ ONLINE GAS TURBINE WASH SYSTEM (7.7.2.10.2)
○ CHLORINE GAS (Cl_2) ______	○ NUMBER OF WASH SKIDS (7.7.2.10.3)
○ HYDROCHLORIC ACID (HCl) ______	______ PORTABLE CARTS ______ FIXED WASH SKIDS
○ NEON (Ne) ______	☐ CLEANING FREQUENCY ______ DAYS
○ OZONE (O_3) ______	REMARKS ______
○ HELIUM (He) ______	______
○ METHANE (CH_4) ______	______
○ KRYPTON (Kr) ______	______
○ HYDROGEN (H_2) ______	
○ NITROUS OXIDE (N_2O) ______	**INLET SILENCERS** (7.7.2.7):
○ CARBON MONOXIDE (CO) ______	☐ SILENCER MFR ______ Δ P ______ mm H_2O
○ XENON (Xe) ______	☐ SILENCER MATERALS ______
○ NITROGEN DIOXIDE (NO_2)	**INLET COOLER TYPE**:
PARTICULATE CONTAMINANTS IN AIR (6.6.8):	○ WETTED-MEDIA (7.7.2.9.2.2.1) ○ ATOMIZING SPRAY (7.7.2.9.2.3.1)
○ SEAWATER ______	○ HEAT EXCHANGER (7.7.2.9.3.1)
○ COASTAL WATER ______	COOLANT-SIDE CONDITIONS (7.7.2.9.3.5):
○ ROADS WITH HEAVY TRAFFIC ______	☐ MAX. AVAILABLE FLOW (L/MIN) ______
○ DRY LAKE BED ______	☐ MAX. TEMP (°C) ______ MIN TEMP (°C) ______
○ NEARBY COOLING TOWER ______	☐ MAX. PRESS. (kPa) ______ MIN. PRESS. (kPa) ______
○ PETROCHEMICAL INDUSTRY ______	☐ COOLANT COMPOSITION OR ANALYSIS ______
○ FOSSIL FIRED POWER PLANT ______	☐ EXCHANGER MFR ______
○ GENERAL CHEMICAL INDUSTRY ______	☐ MODEL ______ Δ P ______ mm H_2O
○ PAPER AND PULP INDUSTRY ______	
○ CEMENT PRODUCTION ______	**REMARKS** ______
○ QUARRIES ______	______
○ AGRICULTURAL ACTIVITIES ______	______
○ PRODUCTION OF FERTILIZERS ______	______
○ MINING AND METALLURGICAL ACTIVITIES	

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ACCESSORIES SUPPLIED BY GAS TURBINE MANUFACTURER

EXHAUST SYSTEM (7.7.3)

☐ EXPANSION JOINT MFR ________ TYPE ________

HEAT RECOVERY SYSTEM

○ RELIEF VALVE ○ DIVERSION VALVE

○ ATMOSPHERIC RELIEF DEVICE (7.7.3.3.2)

☐ TYPE ________ MFR ________

☐ HEAT RECOVERY DEVICE TYPE ________

☐ MFR ________ ΔP ________ mm H_2O

☐ HEAT RECOVERY STEAM GENERATOR

RATE ________ kg/hr PRESS ________ MPag TEMP ________ °C

○ EXHAUST SILENCER PLATE MATERIAL (7.7.3.2.2)

____

○ EXHAUST DUCTWORK INTERFACE POINTS (7.7.1.4.1)

____

☐ SILENCER ________ Δ P ________ mm H_2O

☐ DUCTING GAUGE / MATERIAL ________ / ________

○ EMISSIONS TEST PORTS (7.7.3.3.3) ________

○ EMISSION CONTROL SYSTEM ________

○ EXTENT OF FURNISHED INSULATION (SEE SKETCH) (7.8.1.3)

○ EXHAUST STACK MTL. ________

☐ MANOMETER MFR ________

MODEL ________ RANGE ________ mm H_2O

FIRE PROTECTION (7.8.3)

FIRE EXTINGUISHING SYSTEM (7.8.3.2):

○ NFPA 2001 CLEAN AGENT ○ NFPA 2010 AEROSOL

○ NFPA 750 WATER MIST ○ ISO 14520 CLEAN AGENT

○ NFPA 12 CARBON DIOXIDE ○ ISO 6183 CARBON DIOXIDE

○ MANUAL ACTUATION (7.8.3.4.a)

○ CONTROL ROOM ACTUATION (7.8.3.4.b)

TYPE OF DETECTOR: (7.8.3.7) QUANTITY

☐ ULTRAVIOLET ________

☐ INFRARED ________

☐ HEAT RISE (REQUIRED) ________

GAS DETECTION SYSTEM (7.8.3.9)

○ NFPA 72

○ IEC 60079-29-1 and IEC 60079-29-2

REMARKS: ________

ATMOSPHERIC EMISSIONS (SEE ALSO PAGE 2)

EMISSIONS REDUCTION METHOD (7.9.6.2)

○ WATER INJECTION ○ SCR (7.9.6.3)

○ STEAM ☐ DRY LOW EMISSIONS

○ OTHER ________

APPLICABLE EMISSION CODES OR REGULATIONS

○ EPA - TITLE 40 - CFR ○ OTHERS ________

EMISSION LEVEL (7.9.6.5)

○ INSTANTANEOUS (PPMV) ○ ANNUAL RATE (tons/yr)

REMARKS ________

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INSPECTION AND TESTING; CONTROLS AND INSTRUMENTATION (8.1.1)

SHOP INSPECTION AND TESTS:	REQ	WIT	OBS
CLEANLINESS PRIOR TO ASSEMBLY (8.2.3.3)	○	○	
HYDROSTATIC (8.3.2)		○	○
GAS FUEL SYSTEM PNEUMATIC TEST (8.3.3.1)	○	○	○
MECHANICAL RUN TEST (MRT) (8.3.4)		○	○
ON BASE AUX SYSTEMS INCL IN MRT (8.3.4.1.10)	○	○	○
JOB AUX SYSTEMS INCL IN MRT (8.3.4.2.10)	○	○	○
○ CONTRACT CPLG ○ IDLING ADAPTOR(S)			
○ CONTRACT VIBRATION PROBES			
POLAR VIBRATION PLOTS (8.3.4.3.6.a)	○		
COPY OF VIB DATA (8.3.4.3.8)	○		
SPARE ROTOR IN MRT (8.3.4.2.9)		○	○
PERFORMANCE TEST (8.3.5.1)	○	○	○
○ ISO 2314 ○ ASME PTC			
COMPLETE UNIT TEST (8.3.5.2.1)	○	○	○
FUEL CHANGEOVER TESTS (8.3.5.2.7.a)	○	○	○
STARTS WITH SITE FUEL (8.3.5.2.7.b)	○	○	○
TORSIONAL VIBRATION (8.3.5.2.3)	○	○	○
SOUND PRESSURE LEVEL TEST (8.3.5.3.1)	○	○	○
SOUND POWER LEVEL TEST (8.3.5.3.2)	○	○	○
ROTOR OVERSPEED TEST (8.3.5.4)	○	○	○
AUXILIARY EQUIPMENT TEST (8.3.5.5)	○	○	○
VENTILATION SYSTEM VALIDATION (8.3.5.6)	○	○	○
ENCLOSURE LEAK TEST (8.3.5.7)	○	○	○
GAS TURBINE POST TEST INSPECTION (8.3.5.8)	○	○	○
HYDRAULIC COUPLING HUB/SHAFT FIT (8.3.5.9)	○	○	○
GEN GOV RESPONSE TEST (8.3.5.2.8)	○	○	○
GOV RESPONSE TIME RECORDED (8.3.5.10.1)	○		
OVERSPEED RESP TIME RECORDED (8.3.5.10.2)	○		
SPARE PARTS TEST (8.3.5.11)	○	○	○
FIRE PROTECTION TEST (8.3.5.12)	○	○	○
UNIT CONTROL PANEL FAT (8.3.7)	○	○	○
OTHER TESTS AND INSPECTIONS (8.3.5.13)	○ SEE ATTACHED		
GT FIELD PERFORMANCE TEST (8.3.6)	○	○	○
FIT UP & ASSEMBLY OF PARTS (8.4.9)		○	○
○ SUCCESSFUL PRELIM TESTS PRIOR TO WITNESSED TESTS (8.1.8.2)			
INSPECTOR'S CHECKLIST VERIFIED BY (8.1.6)			
○ PURCHASER ○ VENDOR			

REMARKS: ______

MATERIALS INSPECTION REQUIREMENTS

○ PARTS REQUIRING RADIOGRAPHY TEST, SEE ATTACHED LIST (8.2.1.3)
○ PARTS REQUIRING MAGNETIC PARTICLE TEST, SEE ATTACHED LIST (8.2.1.3)
○ PARTS REQUIRING LIQUID PENETRANT TEST, SEE ATTACHED LIST (8.2.1.3)
○ PARTS REQUIRING ULTRASONIC TEST, SEE ATTACHED LIST (8.2.1.3)
○ 100% WELD INSPECTION (6.24.6.1) ○ X-RAY ○ MAG ○ LPI
○ WELDING HARDNESS TESTING (8.2.3.4)
○ PMI (6.20.17.a through m)
○ PMI ADDITIONAL COMPONENTS (6.20.17.n) - SEE ATTACHED LIST
○ CONNECTION DRAWINGS (6.24.6.4)

MISCELLANEOUS INSPECTION AND TESTING:

○ VENDOR REVIEW & COMMENTS ON PIPING & FOUNDATION (6.5.10.a)
○ SUPPLIER TO OBSERVE PARTING OF FLANGES (6.5.10.b)
○ SUPPLIER CHECK ALIGNMENT AT OPERATING TEMPERATURE (6.5.10.c)
○ SUPPLIER WITNESS INITIAL ALIGNMENT CHECK (6.5.10.d)
○ LIST OF DATA TO KEEP 20 YRS (8.2.1.1.a, 8.2.1.1.g) - SEE ATTACHED LIST

VENDOR'S DATA:

○ DATA TRANSMITTAL IDENTIFIER (9.1.3) ______
○ NUMBER OF PROPOSAL HARDCOPY (9.2.1.a) ______
○ SPARE PARTS OPTIMIZATION ANALYSIS (9.2.3.2.w)
○ FAILURE MODES AND EFFECTS ANALYSIS (9.2.3.2.x)
○ LIFECYCLE ANALYSIS (9.2.3.2.y) ○ DISCOUNT RATE ______ %

PERFORMANCE CURVES (9.2.4)

○ SPEED-TORQUE CURVE OF OUTPUT SHAFT (9.2.4.4.a)
○ INCREMENTAL POWER FOR STEAM/WATER (9.2.4.4.b)
○ EFFECTS OF AIR TEMPERATURE ON EXHAUST FLOW (9.2.4.4.c)
○ RUN DOWN CURVES (9.2.4.4.d)
○ AIR EMISSIONS (9.2.4.4.e)

○ NUMBER OF CONTRACT DATA HARDCOPIES (9.3.1.6) ______

SOFTCOPY DRAWING FORMAT (9.3.2.4)
○ PDF ○ NATIVE CAD ○ OTHER ______

SOFTCOPY IOM MANUAL FORMAT (9.3.6.1.c)
○ PDF ○ OTHER ______

REMARKS: ______

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APPLICABLE TO: PROPOSAL PURCHASE AS-BUILT TECH READINESS LEVEL (6.1.1.1) ____

FOR (9.1.3) ____ UNIT (9.1.3) ____ TRL DOCUMENTATION REQUIRED (6.1.1.2)

SITE (9.1.3) ____ POWER MARGIN (6.1.7) ____ % SERVICE LIFE (6.1.2, 9.2.3.2.y) ____ yrs

SERVICE (9.1.3) ____ NUMBER REQUIRED ____ MINIMUM AVAILABILITY (6.1.5) ____ %

CONTINUOUS INTERMITTENT STANDBY DRIVEN EQUIPMENT ____ MINIMUM RELIABILITY (6.1.5) ____ %

MANUFACTURER ____ MODEL ____ SERIAL NUMBER ____ ISO RATING (3.1.25) ____ HP ____ RPM

NOTE: INFORMATION TO BE COMPLETED: BY PURCHASER BY MANUFACTURER BY MFR IF NOT BY PURCHASER

LOCATION AND SITE CONDITIONS (6.1, 6.6)

INDOOR OUTDOOR UNDER ROOF PARTIAL SIDES IN BUILDING GRADE MEZZANINE HEATED UNHEATED

OTHER ____

EXTREME MAXIMUM AMBIENT TEMPERATURE ____ °F BUILDIING CODE (6.5.13)

EXTREME MINIMUM AMBIENT TEMPERATURE ____ °F ____

MINIMUM DESIGN METAL TEMPERATURE (6.25.7) ____ °F

PIPING STANDARD (6.13.1) ____

ALTITIUDE (6.1.24) ft WINTERIZATION REQD TROPICALIZATION REQD (7.5.8.11, 7.7.2.3.3)

GAS TURBINE ARRANGEMENT (6.1.10 Figure 1):

SINGLE SHAFT

TWO-SHAFT (WITH FREE POWER TURBINE) THREE-SHAFT (WITH FREE POWER TURBINE)

TWO-SHAFT (WITHOUT FREE POWER TURBINE) THREE-SHAFT (WITHOUT FREE POWER TURBINE)

SEISMIC DESIGN CRITERIA (6.6.3, 7.7.1.10)

APPLICABLE CODE ____ APPLICABLE SPECIFICATION ____

WIND DESIGN CRITERIA (6.6.4, 7.7.1.10)

APPLICABLE CODE ____ APPLICABLE SPECIFICATION ____

NONOPERATING EXTREME WIND DESIGN SPEED (6.6.5) ____ MPH ____

(See also Page 16)

ELECTRICAL AREA CLASSIFICATION (6.5.4)

UNCLASSIFIED HAZARDOUS

CLASS ____ DIV/ZONE ____ GROUP ____ TEMP. CODE ____

COMPONENTS IN UNCLASSIFIED LOCATION (7.5.1.6)

CODE: NEC 500 NEC 505 IEC

OUTSIDE GT ENCLOSURES CLASS ____ DIV/ZONE ____ GROUP ____ TEMP. CODE ____

INSIDE GT ENCLOSURES CLASS ____ DIV/ZONE ____ GROUP ____ TEMP. CODE ____

THIRD-PARTY CERTIFICATION ____

ELECTRICAL CODES (6.5.3)

NFPA 70 (NEC) ATEX 2014/34/EU

IEC 60079 CSA C22-1-06

OTHER ____

UNUSUAL CONDITIONS (6.1 and 6.6)

DUST FUMES

APPLICABLE SPECIFICATION FOR DUST LOADING ____

APPLICABLE SPECIFICATION FOR SNOW/ICE LOADING (7.7.1.10) ____

NOISE LIMIT REQUIREMENTS (6.3.1, 6.3.2)

GAS TURBINE ENCLOSURE ____ dBA PRESSURE POWER

INLET SYSTEM ____ dBA PRESSURE POWER

EXHAUST SYSTEM ____ dBA PRESSURE POWER

OVERALL FAR FIELD REQUIREMENT

DOCUMENT HIERARCHY (5.3)

1 ____ 5 ____

2 ____ 6 ____

3 ____ 7 ____

4 ____ 8 ____

VENDOR HAVING UNIT RESPONSIBILITY (4) ____

OTHER

PAINTING (8.4.3.1)

MANUFACTURER'S STANDARD

MANUFACTURER'S STANDARD FOR MARINE ENVIRONMENT

OTHER ____

SHIPMENT (8.4) TRUCK RAIL SHIP

ENVIRONMENTAL CONDITIONS (6.6.2) ____

TRANSPORTATION LOADS (6.5.14, 7.7.1.10) ____

DOMESTIC EXPORT EXPORT BOXING REQUIRED

DURATION OF OUTDOOR STORAGE IF MORE THAN 6 MONTHS (8.4.1.b) ____

SPARE ROTOR ASSEMBLY PACKAGED FOR (8.4.3.11)

DOMESTIC SHIPMENT EXPORT SHIPMENT VERTICAL STORAGE (8.4.3.11.e)

OTHER SPECIFIED LANGUAGE FOR SHIPPING UNIT MARKINGS (8.4.12.1) ____

CASING CONNECTIONS

CASING BOLT THREADING (6.8.1)

ISO 261 ASME B1.1 MIL-S-8879

THREADS TYPE TAPERED STRAIGHT

CASING FLANGES: ISO ASME

MACHINED & STUDDED ISO ASME

REMARKS: ____

REMARKS: ____

GENERAL

CYCLE: REGEN SIMPLE EXHAUST HEAT RECOVERY (7.7.3.1.1.b)

DRIVEN EQUIPMENT POWER RANGE: ______ HP DRIVEN EQUIPMENT SPEED RANGE ______ RPM

GAS TURBINE DRIVER OUTPUT SHAFT SPEED RANGE (6.1.15, 6.1.16, 7.5.3.4) ______ RPM

OPERATION ATTENDED UNATTENDED

POTENTIAL MAXIMUM POWER (3.1.47) ______ HP LIMITING CONDITIONS ______

PERFORMANCE

STEAM OR WATER INJECTION

EMISSIONS (6.2.7) AUGMENTATION (6.2.7)

PERFORMANCE PARAMETERS (6.6)			SITE RATED (3.1.64)	NORMAL OPERATING (3.1.38)	SITE MAX TEMP	SITE MIN TEMP				SITE MIN TURNDOWN
DRIVEN EQUIPMENT PWR	HP	(6.1.7, 7.9.6.1)								
POWER FACTOR (GEN-SET)		(6.1.23)								
INLET DP	in. H_2O	(7.7.2.1.3.2)								
EXHAUST DP	in. H_2O	(7.7.3.1.1)								
AIR DRY BULB TEMP (INLET)	°F	(6.1.24)								
GT INLET AIR COOLING (Y/N)										
GT INLET AIR HEATING (Y/N)										
GT INLET TEMP	°F									
RELATIVE HUMIDITY	%	(6.1.24)								
BAROMETRIC PRESS	PSIA	(6.1.24)								
GT OUTPUT SHAFT POWER	HP									
GG SHAFT SPEED	RPM									
PT OUTPUT SHAFT SPEED	RPM	(6.1.15)								
HEAT RATE (LHV)	Btu/HP-HR									
NO_X EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
CO EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
CO_2 EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
SO_X EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
HYDROCARBON EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
PARTICULATE EMISSIONS	PPMV	(6.2.1, 7.9.6.1)								
FIRING TEMPERATURE	°F									
AIR FLOW	lbm/s									
GG EXHAUST TEMP	°F									
PT EXHAUST FLOW	lbm/s									
PT EXHAUST TEMP	°F									
FUEL TYPE		(6.1.24)								
FUEL FLOWRATE	lbm/h									
FUEL TEMPERATURE	°F									
STEAM FLOW	lbm/h	(6.2.7)								
WATER FLOW	gal/min	(6.2.7)								

AIR COMPRESSOR:

STAGES ______ MAXIMUM TIP SPEED ______ ft/s

TYPE ______ PRESSURE RATIO ______

CASING SPLIT (6.7.3) AXIAL RADIAL

ROTOR SOLID BUILT-UP

TURBINE:

STAGES ______ MAXIMUM TIP SPEED ______ ft/s

CASING SPLIT (6.7.3) AXIAL RADIAL

ROTOR SOLID BUILT-UP

MATERIALS:

COMPRESSOR CASING ______

TURBINE CASING ______

COMBUSTOR LINER ______

COMBUSTOR HEAT SHIELD

COMBUSTORS (6.10)

NUMBER OF COMBUSTORS ______

FUEL NOZZLES PER COMBUSTOR ______

CONFIGURATION ______

MAXIMUM ALLOWABLE TEMP. VARIATION ______ °F

APPLICABLE PLANE ______

COMBUSTOR FLAMEOUT DETECTION (7.5.9.8.2)

FLAME TEMPERATURE SPEED CHANGE

REMARKS: ______

REMARKS: ______

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FUEL SYSTEM (7.9)

TYPE ○ GAS (7.9.1.2) ○ LIQUID (7.9.3) ○ DUAL (7.9.3.10, 7.9.5)

DUAL SYSTEM REQMTS (7.9.3.10, 7.9.5) ○ GAS/GAS ○ LIQUID/GAS ○ LIQUID/LIQUID

○ FUEL GAS COMPRESSION SYSTEM REQD (7.9.1.2.1.4) ☐ MAX TRANSFER TIME (7.9.5.2.a) ____ sec

☐ MIN TRANSFER TIME (7.9.5.2.b) ____ sec

GAS FUELS (7.9.2)

○ HC DEW PT,°F @ PSI ____ @ ____ @ ____ @

○ FUEL ANALYSIS - MOL % (6.1.24.e, 7.9.2.1)

COMPOSITION (7.9.1.1.2)	MW	NORMAL	START-UP	ALTERNATE
AIR	29			
OXYGEN	32			
NITROGEN	38			
WATER VAPOR	18			
CARBON MONOXIDE	28			
CARBON DIOXIDE	44			
HYDROGEN	2			
METHANE	16			
ETHYLENE	26			
ETHANE	30			
PROPYLENE	42			
PROPANE	44			
I-BUTANE	58			
N-BUTANE	58			
I-PENTANE	72			
N-PENTANE	72			
HEXANE PLUS				
TOTAL	%	**100.00**	**100.00**	**100.00**
AVG. MOL. WT.				
☐ LHV	Btu/ft³			
☐ WOBBE INDEX	Btu/ft³			
☐ FUEL TEMP REQ'D	°F			
☐ FUEL PRESS REQ'D	PSIg			

CONTAMINENTS (7.9.1.1.3, 7.9.2.2)

○ TAR	PPM			
○ CARBON BLACK	PPM			
○ COKE	PPM			
○ SOLIDS	PPM			
○ NAPHTHALENE	PPM			
○ GAS HYDRATES	PPM			
○ ____	PPM			

CORROSIVE AGENTS (7.9.1.1.3, 7.9.2.3, 6.20.13)

○ HYD SULFIDE (H2S)	PPM			
○ SULPHUR DIOXIDE	PPM			
○ SULPHUR TRIOXIDE	PPM			
○ TOTAL SULPHUR	PPM			
○ ALKALI METALS	PPM			
○ CHLORIDES	PPM			
○ ____	PPM			

GAS FUEL SYSTEM AND COMPONENTS

- ☐ MANUAL ISOLATION VALVE MFR (7.9.1.2.1.1) ____
- ○ VALVE PRESSURE PROVING (7.9.1.2.7.4)
- ○ EXTERIOR VENT VALVE (7.9.1.2.5.3)
- ☐ PRIMARY FAST SHUT OFF MFR (7.9.1.2.4.4) ____
- ☐ LEAK TIGHT SHUT OFF MFR (7.9.1.2.4.3) ____
- ○ FUEL SHUT-OFF VALVE SUPLLIED BY VENDOR (7.9.1.2.5.1)
  - ☐ MANUFACTURER ____
- ○ DUAL Y-TYPE STRAINERS REQ'D (7.9.1.2.6.2)
- ○ GAS FUEL HEATER SUPPLIED BY VENDOR (7.9.2.5.4)
- ☐ LIQUID FUEL HEATER SUPPLIED BY PURCHASER (7.9.3.13.2)
- ☐ GAS FUEL SUPERHEAT REQMT (7.9.2.1.3) ____ °F
- ○ COALESCING FILTER SIZED FOR DEW POINT CONTROL (7.9.2.2.2)
- ○ RATE OF CHANGE OF WI (7.9.2.4.2) ____ Btu/ft³
- ○ RATE OF CHANGE OF MWI (7.9.2.4.2) ____ Btu/ft³/√°R
- ○ SPECIAL FUEL ANALYSIS EQUIPMT SUPPLIED BY VENDOR (7.9.2.4.3)
  - ☐ CALORIMETER
  - ☐ GAS CHROMATOGRAPH
  - ☐ WOBBE METER
- ○ FUEL GAS LINE PRE-START PURGE SYSTEM (7.9.1.2.1.5)
- ○ FUEL GAS PRESSURE REGULATOR SUPPLIED BY VENDOR (7.9.1.2.1.6)
- ○ VALVE CERTIFICATION REGULATORY AGENCY (7.9.1.2.1.3)

REMARKS: ____

PIPING, TUBING & DESIGN DETAILS

NACE STANDARD (6.20.13)

○ NACE MR0103 ○ MR0175

- ○ FUEL SYSTEM FLANGE RATING ____
- ○ PIPING / TUBING GRADE ____
- ○ TUBE FITTING MFR (7.6.1.9) ____
- ○ MAXIMUM VENT BACKPRESSURE (7.9.1.2.4.7) ____ PSIg

"SHIP LOOSE" FUEL GAS SYSTEM COMPONENTS

- ☐ Y-TYPE STRAINERS ____
- ☐ DUPLEX FUEL GAS FILTERS ____
- ☐ PIPING ____
- ☐ HEATERS ____
- ☐ GAS ANALYSIS EQUIPMENT ____

REMARKS: ____

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FUEL SYSTEM (7.9)

TYPE ○ GAS (7.9.1.2) ○ LIQUID (7.9.3) ○ DUAL (7.9.3.10, 7.9.5)

DUAL SYSTEM REQMTS (7.9.3.10, 7.9.5) ○ GAS/GAS ○ LIQUID/GAS ○ LIQUID/LIQUID

○ FUEL GAS COMPRESSION SYSTEM REQD (7.9.1.2.1.4)

☐ MAX TRANSFER TIME (7.9.5.2.a) ______ sec

☐ MIN TRANSFER TIME (7.9.5.2.b) sec

LIQUID FUEL SYSTEM (7.9.3)

FUEL GRADES (7.9.1.1.2, 7.9.4.1):

- ○ ASTM D2880 GRADE (7.9.4.3)
  - ○ GRADE 0-GT ______
  - ○ GRADE 1-GT ______
  - ○ GRADE 2-GT ______
  - ○ GRADE 3-GT ______
  - ○ GRADE 4-GT ______
- ○ ASTM D1655 (7.9.4.3) ______
  - ○ JET A OR JET A-1 ______
  - ○ JET B ______
- ○ OTHER, INDICATE ANALYSIS (7.9.4.3) ______
- ○ FUEL SHUT-OFF VALVE SUPPLIED BY VENDOR (7.9.3.5.2)
- ○ SECOND STRAINER REQUIRED (7.9.3.7.2)
- ○ FUEL TRANSFER EQUIPMENT SUPPLIED BY VENDOR (7.9.3.14)

LIQUID FUEL TREATMENT REQUIRED ☐ YES ☐ NO

☐ LIQUID FUEL HEATER SUPPLIED BY PURCHASER (7.9.3.13.1, 7.9.3.13.2)

☐ LIQUID FUEL PRESS RANGE ______ PSIg

REMARKS: ______

FUEL PUMP SYSTEM DETAILS

☐ FUEL PUMP PRV SET POINT ______ PSIg

☐ PUMP RATED CAPACITY ______ gal/min

PIPING, TUBING & DESIGN DETAILS

NACE STANDARD (6.20.13)

○ NACE MR0103 ○ MR0175

○ FUEL SYSTEM FLANGE RATING ______

○ PIPING / TUBING GRADE ______

○ TUBE FITTING MFR (7.6.1.9) ______

○ MAXIMUM VENT BACKPRESSURE (7.9.1.2.4.7) PSIg

LIQUID FUEL ANALYSIS (7.9.4)

FUEL ANALYSIS DATA (7.9.4.1) PROPERTY (7.9.1.1.2, 7.9.1.1.3)	ASTM METHOD	MEASURED VALUE
VISCOSITY, cSt @ 100°F	D-445	○
DISTILLATION DATA	D-86	
10% / 50% / 90% RECOVERY, °F MAX		○
END POINT, °F MAX		○
SULFUR CONTENT %WEIGHT, MAX. (SELECT APPL. METHOD)		
BOMB METHOD	D-129	○
LAMP METHOD	D-1266	○
HIGH-TEMP METHOD	D-1552	○
CARBON RESIDUE (ON 10% BOTTOMS)		
% WT. MAX.		○
CONRADSON	D-189	○
RAMSBOTTOM	D-524	○
COPPER STRIP CORROSION PLATE	D-130	
3 HOURS AT 100°F MAXIMUM		○
AROMATIC CONTENT % WT	D-5186	○
ASH CONTENT	D-482	○
SPECIFIC GRAVITY, lbm/ft³ @ 59 °F	D-4052	○
FLASH POINT, °F	D-56	○
CLOUD POINT, °F	D-2500	○
POUR POINT, °F	D-97	○
WATER	D-95	○
PARTICULATES, mg/100 ml	D-2276	○
TRACE METALS (ATOMIC ABSORPTION PREFERRED)	D-3605	○
SODIUM		○
POTASSIUM		○
VANADIUM		○
CALCIUM		○
LEAD		○
OTHER METALS ______		○
LOWER HEATING VALUE, BTU/lbm	D-2382	○
REID VAPOR PRESSURE, bar	D-323	○
OLEFIN CONTENT, % VOL	D-1319	○

REMARKS: ______

REMARKS: ______

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CONSTRUCTION FEATURES - ROTOR No. 1 DESCRIPTION:

☐ SPEEDS: 100 % SPEED ______ RPM
☐ MAX. CONT. ______ RPM ☐ TRIP ______ RPM
☐ LATERAL CRITICAL SPEEDS (DAMPED) (6.16.2.1)

FIRST CRITICAL		RPM		MODE
SECOND CRITICAL		RPM		MODE
THIRD CRITICAL		RPM		MODE
FOURTH CRITICAL		RPM		MODE

☐ PROTOTYPE OR MODIFIED ROTOR SUPPORT (6.16.2.21)
○ TRAIN LATERAL ANALYSIS (6.16.2.8)
○ TRAIN TORSIONAL ANALYSIS (6.16.4.2) TORS SF (6.16.4.8) ______
☐ TORSIONAL CRITICAL SPEEDS:

FIRST CRITICAL		RPM
SECOND CRITICAL		RPM
THIRD CRITICAL		RPM
FOURTH CRITICAL		RPM

○ PURCHASER REVIEW OF CAMPBELL/GOODMAN DIAGRAM (6.14.3.4.6)
VIBRATION (6.16.6.2) (6.16.6.3)
☐ ACCEPTANCE LIMITS: SHAFT ______ mil P-P
CASE ______ in./s
○ INCLUDE MODEL DATA IN LATERAL ANALYSIS (6.16.2.20)
ROTATION, VIEWED FROM DRIVE END ☐ CW ☐ CCW

MATERIALS OF CONSTRUCTION (6.20)

☐ ROTOR BLADES ______
☐ STATOR VANES ______
☐ BLADE/VANE COATING ______
☐ SHAFT ______
☐ TURBINE:

TURBINE STAGE	NOZZLES	BLADES	DISKS or SHROUDS

BALANCING:
○ RESIDUAL UNBALANCE CHECK (6.16.5.2.5)
○ HS BALANCING (6.16.5.3.1)
○ LS RESIDUAL UNBALANCE CHECK AFTER HS BALANCE (6.16.5.3.15)
HIGH-SPEED BALANCING ACCEPTANCE CRITERIA (6.16.5.3.2)
○ GRADE 2.5 ○ ISO 11342 ○ 1.0 in./s
○ EXTRA VIBRATION PROBES DURING TESTING (6.16.5.3.7)

ROLLING ELEMENT BEARINGS AND BEARING HOUSINGS (6.17.2)

RADIAL BEARINGS		DE	NDE
		BRG No:	BRG No:
☐ TYPE			
☐ MANUFACTURER			
☐ SIZE	in.		
☐ RATED SHAFT SPEED	RPM		
☐ RADIAL LOAD	lbf		
☐ BEARING 'C' RATING	lbf		
☐ L-10 BEARING LIFE	hr		
☐ INNER / OUTER RACE MAT'L			
☐ ROLLING ELEMENT MAT'L			
☐ CAGE MATERIAL			
☐ BEARING SPAN			______ in.

RADIAL / THRUST		RADIAL	THRUST
		BRG No:	BRG No:
☐ TYPE			
☐ MANUFACTURER			
☐ SIZE	in.		
☐ RATED SHAFT SPEED	RPM		
☐ RADIAL/THRUST LOAD	lbf		
☐ BEARING 'C' RATING	lbf		
☐ L-10 BEARING LIFE	hr		
☐ INNER / OUTER RACE MAT'L			
☐ ROLLING ELEMENT MAT'L			
☐ CAGE MATERIAL			

HYDRODYNAMIC BEARINGS AND BEARING HOUSINGS (6.17.3, 6.17.5, 6.18)

RADIAL		DE	NDE
		BRG No.	BRG No.
☐ TYPE			
☐ MANUFACTURER			
☐ SHAFT DIAMETER	in.		
☐ BEARING LENGTH	in.		
☐ AREA,	in.²		
☐ UNIT LOAD (ACT/ALLOW)	lbf/in.²		
☐ BASE MATERIAL			
☐ BABBITT THICKNESS	in.		
☐ NO. PADS			
☐ LOAD: BETWEEN/ON PAD			
☐ PIVOT: CENTER/OFFSET	%		
☐ BEARING SPAN			______ in.
☐ DAMPER BEARING			

○ BABBITT TO BACKING ULTRASONIC INSPECTIONS (6.17.3.6)

THRUST		ACTIVE	INACTIVE
		DE/NDE	DE/NDE
☐ TYPE			
☐ MANUFACTURER			
☐ SHAFT DIAMETER	in.		
☐ BEARING SIZE	in.		
☐ AREA	in.²		
☐ UNIT LOAD (ACT/ALLOW)	lbf/in.²		
☐ BASE MATERIAL			
☐ BABBITT THICKNESS	in.		
☐ NO. PADS			
☐ PIVOT: CENTER/OFFSET	%		

LUBRICATION: ☐ FLOODED ☐ DIRECTED
THRUST COLLAR: ☐ INTEGRAL ☐ REPLACEABLE
○ BABBITT TO BACKING ULTRSONIC INSPECTIONS (6.17.5.11)

REMARKS:
______
______

COMBUSTION GAS TURBINE (API 616-6th)	JOB NO.	ITEM NO.	REV
DATASHEET **US CUSTOMARY UNITS**	REVISION	DATE	
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CONSTRUCTION FEATURES - ROTOR No. 1 DESCRIPTION:

BEARING TEMPERATURE SENSORS (7.5.9.3)

USE ATTACHED API 670 DATASHEETS INSTEAD OF THIS DATA SHEET

THERMOCOUPLE TYPE

RTD MATERIAL RESISTANCE Ω

SENSOR LOCATION-JOURNAL BEARING:

NUMBER EA PD EVERY OTH PAD PER BRG

OTHER

SENSOR LOCATION-THRUST BEARING

NO. (ACT) EA PD EVERY OTH PAD PER BRG

OTHER

NO.(INACT) EA PD EVERY OTH PAD PER BRG

OTHER

MONITOR SUPPLIED, INSTALLED AND CALIBRATED (7.5.9.3.4)

MONITOR SUPPLIED BY

LOCATION

MFR MODEL

SCALE RANGE ALARM SET POINT °F

SHUTDOWN SET POINT °F TIME DELAY sec

CASING AND ROLLING ELEMENT VIBRATION TRANSDUCERS (7.5.9.6.2)

SEE ATTACHED API-670 DATASHEETS

MFR MODEL

LOCATION NUMBER

MONITOR SUPPLIED BY

LOCATION

MFR MODEL

SCALE RGE ALARM SET POINT in./s

SHUTDOWN SET POINT in./s TIME DELAY sec

REMARKS:

PROXIMITY PROBES

RADIAL SHAFT VIBRATION PROBES (7.5.9.6.1)

SEE ATTACHED API-670 DATASHEETS

TYPE MODEL

MFR

NO. AT EACH SHAFT BRG TOTAL NO.

OSCILLATOR-DEMODULATOR SUPPLIED BY

MFR MODEL

MONITOR SUPPLIED BY

LOCATION

MFR MODEL

SCALE RANGE ALARM SET POINT mil

SHUTDOWN SET POINT mil TIME DELAY seconds

AXIAL POSITION PROBES (7.5.9.6.1)

SEE ATTACHED API-670 DATASHEETS

TYPE MODEL

MFR NUMBER

OSCILLATOR-DEMODULATOR SUPPLIED BY

MFR MODEL

MONITOR SUPPLIED BY

LOCATION

MFR MODEL

SCALE RANGE ALARM SET POINT mil

SHUTDOWN SET POINT in. TIME DELAY sec

REMARKS:

COMBUSTION GAS TURBINE (API 616-6th)		REV
DATASHEET **US CUSTOMARY UNITS**	JOB NO. ____ ITEM NO. ____ REVISION ____ DATE ____ PAGE 7 OF ____ BY ____	

1 **CONSTRUCTION FEATURES - ROTOR No. 2 DESCRIPTION:**

2 ☐ SPEEDS: 100 % SPEED ____ RPM

3 ☐ MAX. CONT. ____ RPM ☐ TRIP ____ RPM

4 ☐ LATERAL CRITICAL SPEEDS (DAMPED) (6.16.2.1)

5 FIRST CRITICAL ____ RPM ____ MODE

6 SECOND CRITICAL ____ RPM ____ MODE

7 THIRD CRITICAL ____ RPM ____ MODE

8 FOURTH CRITICAL ____ RPM ____ MODE

9 ☐ PROTOTYPE OR MODIFIED ROTOR SUPPORT (6.16.2.21)

10 ○ TRAIN LATERAL ANALYSIS (6.16.2.8)

11 ○ TRAIN TORSIONAL ANALYSIS (6.16.4.2) TORS SF (6.16.4.8) ____

12 ☐ TORSIONAL CRITICAL SPEEDS:

13 FIRST CRITICAL ____ RPM

14 SECOND CRITICAL ____ RPM

15 THIRD CRITICAL ____ RPM

16 FOURTH CRITICAL ____ RPM

17 ○ PURCHASER REVIEW OF CAMPBELL/GOODMAN DIAGRAM (6.14.3.4.6)

18 VIBRATION (6.16.6.2) (6.16.6.3)

19 ☐ ACCEPTANCE LIMITS: SHAFT ____ mil P-P

20 CASE ____ in./s

21 ○ INCLUDE MODEL DATA IN LATERAL ANALYSIS (6.16.2.20)

22 ROTATION, VIEWED FROM DRIVE END ☐ CW ☐ CCW

MATERIALS OF CONSTRUCTION (6.20)

☐ ROTOR BLADES ____

☐ STATOR VANES ____

☐ BLADE/VANE COATING ____

☐ SHAFT ____

☐ TURBINE:

TURBINE STAGE	NOZZLES	BLADES	DISKS or SHROUDS

BALANCING:

○ RESIDUAL UNBALANCE CHECK (6.16.5.2.5)

○ HS BALANCING (6.16.5.3.1)

○ LS RESIDUAL UNBALANCE CHECK AFTER HS BALANCE (6.16.5.3.15)

HIGH-SPEED BALANCING ACCEPTANCE CRITERIA (6.16.5.3.2)

○ GRADE 2.5 ○ ISO 11342 ○ 0.04 in./s

○ EXTRA VIBRATION PROBES DURING TESTING (6.16.5.3.7)

23 **ROLLING ELEMENT BEARINGS AND BEARING HOUSINGS** (6.17.2, 6.18)

Line	RADIAL BEARINGS		DE	NDE	RADIAL / THRUST		RADIAL	THRUST
25			BRG No:	BRG No:			BRG No:	BRG No:
26	☐ TYPE				☐ TYPE			
27	☐ MANUFACTURER				☐ MANUFACTURER			
28	☐ SIZE	in.			☐ SIZE	in.		
29	☐ RATED SHAFT SPEED	RPM			☐ RATED SHAFT SPEED	RPM		
30	☐ RADIAL LOAD	N			☐ RADIAL/THRUST LOAD	N		
31	☐ BEARING 'C' RATING	N			☐ BEARING 'C' RATING	N		
32	☐ L-10 BEARING LIFE	hr			☐ L-10 BEARING LIFE	hr		
33	☐ INNER / OUTER RACE MAT'L				☐ INNER / OUTER RACE MAT'L			
34	☐ ROLLING ELEMENT MAT'L				☐ ROLLING ELEMENT MAT'L			
35	☐ CAGE MATERIAL				☐ CAGE MATERIAL			
36	☐ BEARING SPAN			____ in.				

37

38

39 **HYDRODYNAMIC BEARINGS AND BEARING HOUSINGS** (6.17.3, 6.17.5, 6.18)

Line	RADIAL		DE	NDE	THRUST		ACTIVE	INACTIVE
41			BRG No.	BRG No.			DE/NDE	DE/NDE
42	☐ TYPE				☐ TYPE			
43	☐ MANUFACTURER				☐ MANUFACTURER			
44	☐ SHAFT DIAMETER	in.			☐ SHAFT DIAMETER	in.		
45	☐ BEARING LENGTH	in.			☐ BEARING SIZE	in.		
46	☐ AREA	in.²			☐ AREA	in.²		
47	☐ UNIT LOAD (ACT/ALLOW)	lbf/in.²			☐ UNIT LOAD (ACT/ALLOW)	lbf/in.²		
48	☐ BASE MATERIAL				☐ BASE MATERIAL			
49	☐ BABBITT THICKNESS	in.			☐ BABBITT THICKNESS	in.		
50	☐ NO. PADS				☐ NO. PADS			
51	☐ LOAD: BETWEEN/ON PAD				☐ PIVOT: CENTER/OFFSET	%		
52	☐ PIVOT: CENTER/OFFSET	%			**LUBRICATION:**	☐ FLOODED	☐ DIRECTED	
53	☐ BEARING SPAN			____ in.	**THRUST COLLAR:**	☐ INTEGRAL	☐ REPLACEABLE	
54	☐ DAMPER BEARING							
55	○ BABBITT TO BACKING ULTRASONIC INSPECTIONS (6.17.3.6)				○ BABBITT TO BACKING ULTRSONIC INSPECTIONS (6.17.5.11)			

56 **REMARKS:** ____

57 ____

58

COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
US CUSTOMARY UNITS

JOB NO. ______ ITEM NO. ______
REVISION ______ DATE ______
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☐ **CONSTRUCTION FEATURES - ROTOR No. 2 DESCRIPTION:**

BEARING TEMPERATURE SENSORS (7.5.9.3)

○ USE ATTACHED API 670 DATASHEETS INSTEAD OF THIS DATASHEET
☐ THERMOCOUPLE TYPE ______
☐ RTD MATERIAL ______ RESISTANCE ______ Ω

SENSOR LOCATION-JOURNAL BEARING:
☐ NUMBER ___ EA PD ___ EVERY OTH PAD ___ PER BRG
OTHER ______

SENSOR LOCATION-THRUST BEARING
☐ NO. (ACT) ___ EA PD ___ EVERY OTH PAD ___ PER BRG
OTHER ______
NO.(INACT) ___ EA PD ___ EVERY OTH PAD ___ PER BRG
OTHER ______

○ MONITOR SUPPLIED, INSTALLED AND CALIBRATED (7.5.9.3.4)
MONITOR SUPPLIED BY ______
○ LOCATION ______
MFR ______ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ °F
☐ SHUTDOWN SET POINT ______ °F ☐ TIME DELAY ______ sec

CASING AND ROLLING ELEMENT VIBRATION TRANSDUCERS (7.5.9.6.2)

○ SEE ATTACHED API-670 DATASHEETS
MFR ______ MODEL ______
○ LOCATION ______ NUMBER ______
MONITOR SUPPLIED BY ______
○ LOCATION ______
MFR ______ MODEL ______
☐ SCALE RGE ______ ☐ ALARM SET POINT ______ in./s
☐ SHUTDOWN SET POINT ______ in./s ☐ TIME DELAY ______ sec

REMARKS:

PROXIMITY PROBES

RADIAL SHAFT VIBRATION PROBES (7.5.9.6.1)

○ SEE ATTACHED API-670 DATASHEETS
TYPE ______ MODEL ______
MFR ______
NO. AT EACH SHAFT BRG ______ TOTAL NO. ______
OSCILLATOR-DEMODULATOR SUPPLIED BY ______
MFR ______ MODEL ______
MONITOR SUPPLIED BY ______
LOCATION ______
MFR ______ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ mil
☐ SHUTDOWN SET POINT ______ mil ☐ TIME DELAY ______ seconds

AXIAL POSITION PROBES (7.5.9.6.1)

○ SEE ATTACHED API-670 DATASHEETS
TYPE ______ MODEL ______
MFR ______ NUMBER ______
OSCILLATOR-DEMODULATOR SUPPLIED BY ______
MFR ______ MODEL ______
MONITOR SUPPLIED BY ______
○ LOCATION ______
MFR ______ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ mil
☐ SHUTDOWN SET POINT ______ mil ☐ TIME DELAY ______ sec

REMARKS:

COMBUSTION GAS TURBINE (API 616-6th)	JOB NO. ____ ITEM NO. ____	REV
DATASHEET **US CUSTOMARY UNITS**	REVISION ____ DATE ____ PAGE 9 OF ____ BY ____	

CONSTRUCTION FEATURES - ROTOR No. 3 DESCRIPTION:

☐ SPEEDS: 100 % SPEED ____ RPM
☐ MAX. CONT. ____ RPM ☐ TRIP ____ RPM
☐ LATERAL CRITICAL SPEEDS (DAMPED) (6.16.2.1)

FIRST CRITICAL		RPM		MODE
SECOND CRITICAL		RPM		MODE
THIRD CRITICAL		RPM		MODE
FOURTH CRITICAL		RPM		MODE

☐ PROTOTYPE OR MODIFIED ROTOR SUPPORT (6.16.2.21)
○ TRAIN LATERAL ANALYSIS (6.16.2.8)
○ TRAIN TORSIONAL ANALYSIS (6.16.4.2) TORS SF (6.16.4.8) ____
☐ TORSIONAL CRITICAL SPEEDS:

FIRST CRITICAL		RPM
SECOND CRITICAL		RPM
THIRD CRITICAL		RPM
FOURTH CRITICAL		RPM

○ PURCHASER REVIEW OF CAMPBELL/GOODMAN DIAGRAM (6.14.3.4.6)
VIBRATION (6.16.6.2) (6.16.6.3)
☐ ACCEPTANCE LIMITS: SHAFT ____ mil P-P
CASE ____ in./s
○ INCLUDE MODEL DATA IN LATERAL ANALYSIS (6.16.2.20)
ROTATION, VIEWED FROM DRIVE END ☐ CW ☐ CCW

MATERIALS OF CONSTRUCTION (6.20)

☐ ROTOR BLADES ____
☐ STATOR VANES ____
☐ BLADE/VANE COATING ____
☐ SHAFT ____
☐ TURBINE:

TURBINE STAGE	NOZZLES	BLADES	DISKS or SHROUDS

BALANCING:
○ RESIDUAL UNBALANCE CHECK (6.16.5.2.5)
○ HS BALANCING (6.16.5.3.1)
○ LS RESIDUAL UNBALANCE CHECK AFTER HS BALANCE (6.16.5.3.15)
HIGH-SPEED BALANCING ACCEPTANCE CRITERIA (6.16.5.3.2)
○ GRADE 2.5 ○ ISO 11342 ○ 0.04 in./s
○ EXTRA VIBRATION PROBES DURING TESTING (6.16.5.3.7)

ROLLING ELEMENT BEARINGS AND BEARING HOUSINGS (6.17.2)

RADIAL BEARINGS		DE	NDE	RADIAL / THRUST		RADIAL	THRUST
		BRG No:	BRG No:			BRG No:	BRG No:
☐ TYPE				☐ TYPE			
☐ MANUFACTURER				☐ MANUFACTURER			
☐ SIZE	in.			☐ SIZE	in.		
☐ RATED SHAFT SPEED	RPM			☐ RATED SHAFT SPEED	RPM		
☐ RADIAL LOAD	lbf			☐ RADIAL/THRUST LOAD	lbf		
☐ BEARING 'C' RATING	lbf			☐ BEARING 'C' RATING	lbf		
☐ L-10 BEARING LIFE	hr			☐ L-10 BEARING LIFE	hr		
☐ INNER / OUTER RACE MAT'L				☐ INNER / OUTER RACE MAT'L			
☐ ROLLING ELEMENT MAT'L				☐ ROLLING ELEMENT MAT'L			
☐ CAGE MATERIAL				☐ CAGE MATERIAL			

☐ BEARING SPAN ____ in.

HYDRODYNAMIC BEARINGS AND BEARING HOUSINGS (6.17.3, 6.17.5, 6.18)

RADIAL		DE	NDE	THRUST		ACTIVE	INACTIVE
		BRG No.	BRG No.			DE/NDE	DE/NDE
☐ TYPE				☐ TYPE			
☐ MANUFACTURER				☐ MANUFACTURER			
☐ SHAFT DIAMETER	in.			☐ SHAFT DIAMETER	in.		
☐ BEARING LENGTH	in.			☐ BEARING SIZE	in.		
☐ AREA,	$in.^2$			☐ AREA	$in.^2$		
☐ UNIT LOAD (ACT/ALLOW)	$lbf/in.^2$			☐ UNIT LOAD (ACT/ALLOW)	$lbf/in.^2$		
☐ BASE MATERIAL				☐ BASE MATERIAL			
☐ BABBITT THICKNESS	in.			☐ BABBITT THICKNESS	in.		
☐ NO. PADS				☐ NO. PADS			
☐ LOAD: BETWEEN/ON PAD				☐ PIVOT: CENTER/OFFSET	%		
☐ PIVOT: CENTER/OFFSET	%						

LUBRICATION: ☐ FLOODED ☐ DIRECTED
THRUST COLLAR: ☐ INTEGRAL ☐ REPLACEABLE

☐ BEARING SPAN ____ in.
☐ DAMPER BEARING
○ BABBITT TO BACKING ULTRASONIC INSPECTIONS (6.17.3.6)
○ BABBITT TO BACKING ULTRASONIC INSPECTIONS (6.17.5.11)

REMARKS:

COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
US CUSTOMARY UNITS

JOB NO. ______ ITEM NO. ______
REVISION ______ DATE ______
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☐ **CONSTRUCTION FEATURES - ROTOR No. 3 DESCRIPTION:**

BEARING TEMPERATURE SENSORS (7.5.9.3)

○ USE ATTACHED API 670 DATASHEETS INSTEAD OF THIS DATASHEET
☐ THERMOCOUPLE TYPE ______
☐ RTD MATERIAL ______ RESISTANCE ______ Ω

SENSOR LOCATION-JOURNAL BEARING:
☐ NUMBER ___ EA PD ___ EVERY OTH PAD ___ PER BRG
OTHER ______
SENSOR LOCATION-THRUST BEARING
☐ NO. (ACT) ___ EA PD ___ EVERY OTH PAD ___ PER BRG
OTHER ______
NO.(INACT) ___ EA PD ___ EVERY OTH PAD ___ PER BRG
OTHER ______
○ MONITOR SUPPLIED, INSTALLED AND CALIBRATED (7.5.9.3.4)
◙ MONITOR SUPPLIED BY ______
○ LOCATION ______
◙ MFR ______ ◙ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ °F
☐ SHUTDOWN SET POINT ______ °F ☐ TIME DELAY ______ sec

CASING AND ROLLING ELEMENT VIBRATION TRANSDUCERS (7.5.9.6.2)

○ SEE ATTACHED API-670 DATASHEETS
◙ MFR ______ ◙ MODEL ______
○ LOCATION ______ ◙ NUMBER ______
◙ MONITOR SUPPLIED BY ______
○ LOCATION ______
◙ MFR ______ ◙ MODEL ______
☐ SCALE RGE ______ ☐ ALARM SET POINT ______ in./s
☐ SHUTDOWN SET POINT ______ in./s ☐ TIME DELAY ______ sec

REMARKS: ______

PROXIMITY PROBES

RADIAL SHAFT VIBRATION PROBES (7.5.9.6.1)

○ SEE ATTACHED API-670 DATASHEETS
◙ TYPE ______ ◙ MODEL ______
◙ MFR ______
◙ NO. AT EACH SHAFT BRG ______ TOTAL NO. ______
◙ OSCILLATOR-DEMODULATOR SUPPLIED BY ______
◙ MFR ______ ◙ MODEL ______
◙ MONITOR SUPPLIED BY ______
◙ LOCATION ______
◙ MFR ______ ◙ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ mil
☐ SHUTDOWN SET POINT ______ mil ☐ TIME DELAY ______ seconds

AXIAL POSITION PROBES (7.5.9.6.1)

○ SEE ATTACHED API-670 DATASHEETS
◙ TYPE ______ ◙ MODEL ______
◙ MFR ______ ◙ NUMBER ______
◙ OSCILLATOR-DEMODULATOR SUPPLIED BY ______
◙ MFR ______ ◙ MODEL ______
◙ MONITOR SUPPLIED BY ______
○ LOCATION ______
◙ MFR ______ ◙ MODEL ______
☐ SCALE RANGE ______ ☐ ALARM SET POINT ______ mil
☐ SHUTDOWN SET POINT ______ mil ☐ TIME DELAY ______ sec

REMARKS: ______

COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
US CUSTOMARY UNITS

JOB NO. ______ ITEM NO. ______
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UTILITIES (9.2.3.2.i)

UTILITY CONDITIONS:

STEAM: **AUXILIARY DRIVERS** **HEATING**

INLET MIN	PSIg	°F	PSIg	°F
NORM	PSIg	°F	PSIg	°F
MAX	PSIg	°F	PSIg	°F
EXHST MIN.	PSIg	°F	PSIg	°F
NORM	PSIg	°F	PSIg	°F
MAX	PSIg	°F	PSIg	°F

STARTING **INJECTION**

INLET MIN	PSIg	°F	PSIg	°F
NORM	PSIg	°F	PSIg	°F
MAX	PSIg	°F	PSIg	°F
EXHST MIN.	PSIg	°F		
NORM	PSIg	°F		
MAX	PSIg	°F		

INLET AIR EVAPORATIVE COOLING / FOGGING WATER:
INLET TEMPERATURE ______ °F
DESIGN TEMPERATURE ______ °F
NORM PRESS ______ PSIg
DESIGN PRESS ______ PSIg
WATER QUALITY ______

COOLING WATER:
INLET TEMPERATURE ______ °F MAX RETURN ______ °F
DESIGN TEMPERATURE ______ °F
NORM PRESS ______ PSIg MIN RETURN ______ PSIg
DESIGN PRESS ______ PSIg MAX ALLOW ΔP ______ PSId
WATER SOURCE ______

INLET AIR CHILLING (IAC) WATER:
INLET TEMPERATURE ______ °F MAX RETURN ______ °F
DESIGN TEMPERATURE ______ °F
NORM PRESS ______ PSIg MIN RETURN ______ PSIg
DESIGN PRESS PSIg MAX ALLOW D P PSIg

TOTAL UTILITY CONSUMPTION:
IAH / COOLING / IAC WATER ______ / ______ / ______ gal/min
STEAM LEVEL ______ PSIg ______ PSIg ______ PSIg
STEAM, NORMAL ______ lbm/h ______ lbm/h ______ lbm/h
STEAM, MAX ______ lbm/h ______ lbm/h ______ lbm/h
INSTRUMENT AIR ______ SCFM
NITROGEN ______ SCFM
MOTORS (AUXILIARIES) ______ HP
BATTERY CHARGERS ______ HP
HEATERS ______ HP

GAS TURBINE AIR EXTRACTION (7.7.2.8.1, 7.7.2.9.4.5)
FLOW ______ SCFM PRESS ______ PSIg TEMP ______ °F
MAXIMUM PRESSURE AVAILABLE AT MINIMUM SPEED: ______ PSIg
MINIMUM SPEED: ______ RPM
DISCHARGE TEMPERATURE ______ °F
COMPRESSOR EXTRACTION STAGE NUMBER: ______
BLEED VALVE DESIGN APPROVAL REQUIRED (7.7.2.8.7)

INSTRUMENT AIR PRESSURE DESIGN, PSIg ______
MAX ______ NORMAL ______ MIN ______
NITROGEN PRESSURE DESIGN ______ PSIg
MAX ______ NORMAL ______ MIN ______

ELECTRICITY (7.5.8.1)

	MOTORS	HEATING	CONTROL	SHUTDOWN
VOLTAGE				
HERTZ				
PHASE				

ALARM IN LIEU OF PILOT LIGHTS (7.5.8.3.2)

REMARKS: ______

PURCHASER CONNECTIONS (6.13) (7.6)

MAIN CONNECTION	WELDING DESIGN APPROVAL (6.24.6.4)	SIZE	FACING AND RATING	INLET & EXHAUST ORIENTATION (7.7.1.2)	FLANGED OR STUDDED	MATING FLG AND GASKET BY VENDOR (6.13.6)	GAS VELOCITY ft/s

COMBUSTION GAS TURBINE (API 616-6th)

DATASHEET
US CUSTOMARY UNITS

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INSTRUMENTATION, LUBRICATION & HARDWARE

OUTDOOR CONTROLS AND INSTRUMENTATION CODE (7.5.1.2.1, 7.5.8.18)
○ IEC 60529 IP66 ○ NEMA 250 4X ○ OTHER ______
INSTRUMENTATION MOUNTING (7.5.1.2) ○ INDOOR ○ OUTDOOR

○ REDUNDANT CONTROL SYSTEM EQUIPMENT (7.5.2.15)
○ REDUNDANT SENSORS AND INPUTS PER API 614 (7.5.2.16)
○ UPS DURATION (7.5.2.18) ______ MINUTES
CONTROL SYSTEM POWER (7.5.6.5) ○ AC ○ DC
○ DCS LINK REQD (7.5.2.19)
DCS DATA COMMUNICATION FREQUENCY (7.5.2.20) ______ ms
○ SIL RATING (7.5.2.24) ______
○ SPECIAL MOUNTING ARRANGEMENTS REQD (7.5.5.13)
○ SHUTDOWN SENSING DEVICE ISOLATION REQ'D (7.5.5.29)
○ CONFORMAL COATINGS ON PRINTED CIRCUIT BOARDS (7.5.6.11)
○ EVENT RECORDER REQUIRED (7.5.5.27)
☐ GAUGE BOARD LOCATION
○ SEPARATE TACHOMETER DISPLAY (7.5.9.1.2)
SPEED SENSOR (7.5.9.1.3) ○ ACTIVE ○ PASSIVE
◘ TACHOMETER MANUFACTURER ______
○ GLYCERINE-FILLED GAUGES (7.5.9.4.2)
CONTROL WIRING (7.5.8.21.8): ○ ARMORED ○ METAL CONDUIT
CONTROL SYSTEM DETAILS:
MACHINERY PROTECTION ARRANGEMENTS (7.5.5.1)
☐ DISTRIBUTED ☐ INTEGRATED
○ SWITCHES ALLOWED FOR ALARM, TRIP & SHUTDOWN (7.5.5.14.2)
○ REQ'D COMMUNICATION PROTOCOL (7.5.7.5) ______
○ FIRST-OUT ANNUNCIATOR REQ'D (7.5.5.23)

LOAD CONTROL - GOVERNOR (7.5.3)

◘ MAKE ______ ◘ MODEL ______
◘ ISOCHRONOUS ◘ DROOP
◘ REMOTE SHUTDOWN SIGNAL TYPE: ______
☐ CONTROL SIGNAL RANGE (7.5.3.4) mA

CONTROL SYSTEMS

NONLOGIC SOLVER CONTROL TYPES (7.5.2.11):
☐ MECH | ○ PNEU ☐ HYDRAULIC ☐ ELECTRIC
☐ MICROPROCESSOR BASED ☐ ELECTRONIC
CONTROL CONSOLES (7.5.6.2)
○ OFF-SKID INDOOR ○ OFF-SKID OUTDOOR ○ ON-SKID (7.5.6.3)
○ OFF-SKID CONTROL PANEL CABLE LENGTH (7.5.6.2 b) ______ ft
ADDITIONAL HMI QUANTITY (7.5.7.4)
○ PORTABLE ______ ○ DESKTOP ______ ○ PANEL ______
○ HMI START-UP GRAPHICS REQ'D (7.5.7.6.3)
STARTING SYSTEM (7.5.2.5)
○ MANUAL ○ SEMI-AUTOMATIC ○ AUTOMATIC
☐ PURGE PERIOD (7.5.4, 7.5.4.2) ______ MINUTES

REMARKS: ______

LUBRICATION SYSTEMS
○ API 614 (6.19.6)
MINERAL LUBE SYSTEM (6.19.5)
◘ OIL VISCOSITY
◘ LUBE SPECIFICATION ______

COMMON TO ◘ GAS GENERATOR or SINGLE SHAFT GT
◘ FREE POWER TURBINE ◘ LOAD GEAR
◘ DRIVEN EQUIPMENT ◘ AUXILIARIES
SYNTHETIC LUBE OIL SYSTEM (6.19.3, 6.19.5)
◘ USE SYNTHETIC LUBE (6.19.3, 6.19.5)
◘ OIL VISCOSITY
◘ LUBE SPECIFICATION ______

COMMON TO ◘ GAS GENERATOR or SINGLE SHAFT GT
◘ FREE POWER TURBINE ◘ LOAD GEAR
◘ DRIVEN EQUIPMENT ◘ AUXILIARIES
○ REAL-TIME OIL DEBRIS DETECTION AND DISPLAY (7.5.9.7.2)

☐ **OIL REQUIREMENTS**

	FLOW (m^3/h)	PRESSURE (PSIg)	HEAT LOAD (HP)
GAS GENERATOR			
POWER TURBINE			
HYD START SYSTEM			

MINERAL OIL RESERVOIR CAPACITY ______ liters
SYNTHETIC OIL RESERVOIR CAPACITY ______ liters
HYDRAULIC OIL RESERVOIR CAPACITY ______ liters
HYDRAULIC OIL SPECIFICATION

WEIGHTS & DIMENSIONS

	☐ INSTALLED (lbm)	☐ SHIPPING (lbm)	☐ DIMENSIONS LxWxH (m)
GAS GENERATOR			
POWER TURBINE			
GT ENCLOSURE			
INLET FILTER HOUSE			
INLET AIR DUCTING			
VENT DUCTING			
EXHAUST DUCTING			
MIN OIL CONSOLE			
SYN OIL CONSOLE			
MIN OIL SEPARATOR			
SYN OIL SEPARATOR			
MIN OIL AIR COOLER			
SYN OIL AIR COOLER			
HYD START SKID			
CO_2 CYLINDER SKID			
WATER WASH SKID			
TOTAL PACKAGE WT			
MAX ERECTION WT		ITEM	
MAX MAINT WT		ITEM	

○ MEASURE GT PACKAGE WEIGHT AND CENTER OF GRAVITY (8.4.3.9)

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DESCRIPTION (7.5.5.13.1)	INSTRUMENT TYPE: INDICATING	INSTRUMENT TYPE: RECORDING	INSTRUMENT LOCATION: LOCAL	INSTRUMENT LOCATION: LOCAL PANEL	INSTRUMENT LOCATION: CONTROL ROOM	TRANSMITTERS FURNISHED BY: VENDOR	TRANSMITTERS FURNISHED BY: OTHERS	CONTROL ROOM RECEIVERS FURN BY: VENDOR	CONTROL ROOM RECEIVERS FURN BY: OTHERS
SINGLE OR MULTI-SHAFT GAS TURBINE									
TACHOMETER(S)	○	○	○	○	○	○	○	○	○
AIR INLET SYSTEM ΔP	○	○	○	○	○	○	○	○	○
COMPRESSOR DISCHARGE PRESSURE	○	○	○	○	○	○	○	○	○
FUEL FILTER DP	○	○	○	○	○	○	○	○	○
FUEL SUPPLY PRESSURE	○	○	○	○	○	○	○	○	○
STARTING GAS SUPPLY PRESSURE	○	○	○	○	○	○	○	○	○
STARTING GAS EXHAUST PRESSURE	○	○	○	○	○	○	○	○	○
TEMP COMBUSTOR MEASUREMENT	○	○	○	○	○	○	○	○	○
TEMP GAS TURB CONTROL PANEL	○	○	○	○	○	○	○	○	○
INLET AIR TEMPERATURE	○	○	○	○	○	○	○	○	○
TEMPERATURE, GG COMPRESSOR DISCHARGE	○	○	○	○	○	○	○	○	○
TEMPERATURE, RADIAL BEARING	○	○	○	○	○	○	○	○	○
TEMPERATURE, THRUST BEARING	○	○	○	○	○	○	○	○	○
TEMPERATURE, FUEL MANIFOLD	○	○	○	○	○	○	○	○	○
TEMPERATURE, LUBE OIL RESERVOIR	○	○	○	○	○	○	○	○	○
FIRED HOUR METER									
A) NUMBER STARTS COUNTER	○	○	○	○	○	○	○	○	○
B) START SEQUENCE TIMER	○	○	○	○	○	○	○	○	○
LUBE OIL INLET PRESSURE	○	○	○	○	○	○	○	○	○
LUBE OIL INLET TEMPERATURE	○	○	○	○	○	○	○	○	○
LUBE OIL RESERVOIR LEVEL	○	○	○	○	○	○	○	○	○
LUBE OIL PUMP PRESSURE INDICATORS (NO.)	○	○	○	○	○	○	○	○	○
LUBE OIL COOLER OIL INLET TEMPERATURE	○	○	○	○	○	○	○	○	○
LUBE OIL COOLER OIL OUTLET TEMPERATURE	○	○	○	○	○	○	○	○	○
LUBE OIL COOLER COOLANT INLET TEMPERATURE	○	○	○	○	○	○	○	○	○
LUBE OIL COOLER COOLANT OUTLET TEMPERATURE	○	○	○	○	○	○	○	○	○
LUBE OIL FILTER DP	○	○	○	○	○	○	○	○	○
LUBE OIL PRESSURE EACH LEVEL (NO.)	○	○	○	○	○	○	○	○	○
CONTROL OIL PRESSURE	○	○	○	○	○	○	○	○	○
SITE FLOW INDICATOR EACH DRAIN (NO.)	○	○	○	○	○	○	○	○	○
INLET GUIDE VANE POSITION INDICATOR	○	○	○	○	○	○	○	○	○
EXHAUST DUCT DIFFERENTIAL PRESSURE INDICATOR	○	○	○	○	○	○	○	○	○
TEMPERATURE, EXHAUST	○	○	○	○	○	○	○	○	○
ENCLOSURE COOLING AIR EXHAUST TEMPERATURE	○	○	○	○	○	○	○	○	○
POWER TURBINE									
TACHOMETER(S) (NO.)	○	○	○	○	○	○	○	○	○
TEMPERATURE, EXHAUST	○	○	○	○	○	○	○	○	○
TEMPERATURE, RADIAL BEARING	○	○	○	○	○	○	○	○	○
TEMPERATURE, THRUST BEARING	○	○	○	○	○	○	○	○	○
SITE FLOW INDICATOR EACH DRAIN (NO.)	○	○	○	○	○	○	○	○	○
LUBE OIL INLET PRESSURE	○	○	○	○	○	○	○	○	○
LUBE OIL INLET TEMPERATURE	○	○	○	○	○	○	○	○	○

REMARKS:

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1	**ALARMS AND SHUTDOWNS** (7.5.5.13, 7.5.5.13.1)								
2	**DESCRIPTION**	APPLIES TO:		ANNUNCIATED IN FIRST OUT PANEL SUPPLIED BY VENDOR (7.5.5.23)		SENSING DEVICES TO BE FURNISHED BY		INDICATING LIGHT ONLY	
3–5	○ SEE ATTACHED API 614 DATASHEET (7.5.5.14)	SINGLE SHAFT OR GG	FREE PT	ALARM	SHUT-DOWN	VENDOR	OTHERS		
6	RADIAL SHAFT VIBRATION	○	○	○	○	○	○	☐	
7	AXIAL THRUST POSITION	○	○	○	○	○	○	☐	
8	OVERSPEED	○	○	○	○	○	○	☐	
9	CASING VIBRATION	○	○	○	○	○	○	☐	
10	HIGH THRUST BEARING TEMPERATURE	○	○	○	○	○	○	☐	
11	HIGH RADIAL BEARING TEMPERATURE	○	○	○	○	○	○	☐	
12	LOW FUEL SUPPLY PRESSURE	○	○	○	○	○	○	☐	
13	HIGH FUEL FILTER Δ P	○	○	○	○	○	○	☐	
14	GAS TURBINE TEMPERATURE SPREAD HIGH	○	○	○	○	○	○	☐	
15	EXHAUST OVER TEMPERATURE	○	○	○	○	○	○	☐	
16	FAILURE OF OVER-TEMPERATURE SHUTDOWN DEVICE	○	○	○	○	○	○	☐	
17	HIGH INLET AIR Δ P EACH FILTER	○	○	○	○	○	○	☐	
18	COMBUSTOR FLAME-OUT	○	○	○	○	○	○	☐	
19	CHIP DETECTOR, BEARING	○	○	○	○	○	○	☐	
20	FAILURE STARTING CLUTCH TO ENGAGE OR DISENGAGE	○	○	○	○	○	○	☐	
21	LOW OIL PRESSURE	○	○	○	○	○	○	☐	
22	HIGH LUBE OIL TEMPERATURE	○	○	○	○	○	○	☐	
23	LOW LUBE OIL RESERVOIR LEVEL	○	○	○	○	○	○	☐	
24	HIGH LUBE OIL RESERVOIR LEVEL	○	○	○	○	○	○	☐	
25	HIGH OIL FILTER Δ P	○	○	○	○	○	○	☐	
26	LUBE OIL SPARE PUMP OPERATING	○	○	○	○	○	○	☐	
27	LOW CONTROL OIL PRESSURE	○	○	○	○	○	○	☐	
28	LOW STARTING GAS PRESSURE	○	○	○	○	○	○	☐	
29	ANTI-ICING SYSTEM - NOT OPERATING	○	○	○	○	○	○	☐	
30	LOW D.C. VOLTAGE	○	○	○	○	○	○	☐	
31	EMERGENCY D.C. PUMP OPERATING	○	○	○	○	○	○	☐	
32	RESERVOIR HEATER "ON"	○	○	○	○	○	○	☐	
33	IMPLOSION DOOR OPEN	○	○	○	○	○	○	☐	
34	EXTERNAL PERMISSIVE START SIGNAL	○	○	○	○	○	○	☐	
35	EXTERNAL SHUTDOWN SIGNAL	○	○	○	○	○	○	☐	
36	LOSS OF AUXILIARY COOLING AIR	○	○	○	○	○	○	☐	
37	LAMP TEST PUSH BUTTON	○	○	○	○	○	○	☐	
38	ENCLOSURE HIGH TEMPERATURE	○	○	○	○	○	○	☐	
39	CONTROL SIGNAL FAILURE	○	○	○	○	○	○	☐	
40	CONTROL SYSTEM ACTUATOR FAILURE	○	○	○	○	○	○	☐	
41	GOVERNOR FAILURE	○	○	○	○	○	○	☐	
42	ENCLOSURE VENT FAN FAILURE	○	○	○	○	○	○	☐	
43	SPARE ENCLOSURE VENT FAN OPERATING	○	○	○	○	○	○	☐	
44	WOBBE METER	○	○	○	○	○	○	☐	
45	GAS CHROMATOGRAPH	○	○	○	○	○	○	☐	
46	EXHAUST GAS ANALYZER	○	○	○	○	○	○	☐	
47	**REMARKS:** ______								
48	______								
49	______								
50									

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ACCESSORIES SUPPLIED BY MANUFACTURER OR PACKAGER

STARTING AND HELPER DRIVERS (7.1.1.1, 7.1.2.1)

○ STARTER ONLY ○ STARTER/HELPER
TYPE (7.1.2.1) ○ MOTOR: ○ API 541 ○ API 546 ○ IEC 60034-1
○ GAS EXPANDER ○ IC ENGINE ○ HYDRAULIC
☐ STARTER IS CLUTCHED (7.1.1.5)
☐ HELPER RATING (7.1.3.3) ________ HP
☐ STARTER RATING (7.1.3) ________ HP
○ SHAFT TURNING GEAR OR RACHET DEVICE REQUIRED (7.1.4.1)

☐ **MOTOR (STARTER ONLY):**
TYPE ________ RATING ________ HP
MFR ________ MODEL ________
○ REDUCED VOLTAGE STARTING (7.1.2.6) ________ %

☐ **MOTOR (STARTER / HELPER):**
TYPE ________ RATING ________ HP
MFR ________ MODEL ________
REDUCED VOLTAGE STARTING (7.1.2.6) ________ %

GAS EXPANDER
○ APPLICABLE SPEC. (7.1.1.4) ________
☐ MFR ________ MODEL ________
☐ RATING ________ HP
☐ TOTAL/START ________ lbm ☐ MAX. GAS FLOW ________ lbm/h
GAS FOR EXPANDER: ○ AIR ○ NATURAL GAS

	MIN	MAX	NORMAL
☐ INLET PRESSURE PSIg			
☐ EXHAUST PRESS PSIg			
☐ GAS TEMPERATURE, °F INLET			
☐ GAS TEMPERATURE, °F EXHAUST			
○ MOLECULAR WEIGHT			

SPEED CONTROL ☐ GOVERNOR ☐ PRESSURE REGULATOR

DESIGN DETAILS:	YES	NO
INLET CONTROL VALVE FURNISHED	☐	☐
STAINLESS STEEL PIPING MANIFOLD	☐	☐
CARBON STEEL FLANGES	☐	☐
Y-STRAINER W/BREAKOUT FLANGES	☐	☐
LOW SPEED CAPABILITY (FOR COMPRESSOR CLEANING)	☐	☐

☐ RELIEF VALVE PRESSURE SET POINT ________ PSIg
☐ CASING MATERIAL ________
☐ SEAL TYPE ________

INTERNAL COMBUSTION ENGINE
TYPE ○ SPARK IGNITED ○ DIESEL
○ APPLICABLE SPEC. (7.1.1.4) ________
☐ MFR ________ ☐ MODEL ________
☐ SPEED ________ RPM ☐ RATING ________ HP

STEAM TURBINE (REFER TO API DATASHEETS)
○ APPLICABLE SPEC. (7.1.1.4) ________
☐ MFR ________ ☐ MODEL ________
☐ RATING ________ HP ☐ MAX. STEAM FLOW ________ lbm/h
☐ TOTAL FLOW / START ________ lbm

GEARS
○ LOAD GEAR SUPPLIED BY GAS TURBINE OEM (7.2.1.2)
☐ LOAD AND HELPER SEE API 613 GEAR DATASHEETS (7.2.1.1)
☐ STARTERS SEE API 677 GEAR DATASHEETS (7.1.1.6)

MOUNTING PLATES (7.3)
TYPE ○ SOLEPLATE ○ BASEPLATE
☐ SHIM PACK THICKNESS ________ in.
SPECIFIED GROUT (7.3.1.1) ○ EPOXY ○ CEMENTITIOUS

BASEPLATE (7.4)
TYPE (7.4.1.1, 7.4.1.12)
○ 3-POINT ○ COLUMN ○ PERIMETER
○ FULL GROUT (7.4.1.20)
BASEPLATE CONTAINS
☐ GAS TURBINE ☐ GEAR ☐ ACCESSORIES ☐ DRIVEN EQUIPMENT
○ PROVIDE LIFTING EQUIPMENT (7.4.1.17)
GRATING REQUIREMENTS (7.4.1.23) ○ SS ○ GRP
○ DESIGN FOR OPTICAL/LASER FIELD LEVELING (7.4.1.11)
○ SUB-SOLEPLATES REQUIRED (7.4.2.1)
○ LESS 55 lbm MANWAY DOORS REQ DAVIT (7.7.1.11.2)

ENCLOSURES
○ AUXILIARY EQUIPMENT ENCLOSURE(S) (7.8.4.2)
○ DRIVEN EQUIPMENT ENCLOSURE(S) (7.8.4.3)
ADDITIONAL VENTILATION FANS (7.8.4.19.2)
○ 1X100% ○ 2X100% ○ 3X50%
○ OTHER ________

COUPLINGS AND GUARDS (7.2.2)
COUPLINGS
SEE ATTACHED API 671 DATASHEETS
○ LESS THAN 4000 RPM COUPLINGS DESIGNED TO ISO 14691 (7.2.2.7):
☐ MFR ________ ☐ TYPE ________
☐ MODEL ________ ☐ GUARD SUPPLIED BY ________
☐ MAXIMUM OUTSIDE DIAMETER ________ in.
☐ HUB WEIGHT ________ lbm
☐ SPACER LENGTH ________ in. ☐ SPACER WEIGHT lbm ________
○ TORQUE MONITORING SYSTEM (7.2.2.3)

COUPLING GUARDS ________
TYPE: ○ FULLY-ENCLOSED ○ SEMI-OPEN ○ OTHER ________

MAINTENANCE INTERVALS, HOURS / DURATION, HOURS
☐ BORESCOPE INSPECTION ________ / ________
☐ HOT SECTION OVERHAUL ________ / ________
☐ MAJOR OVERHAULS ________ / ________

REMARKS ________

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1	**ACCESSORIES SUPPLIED BY GAS TURBINE MANUFACTURER**	
2	**ENVIRONMENTAL CONDITIONS** (6.6)	**INLET SYSTEM** (7.7.2)
3	**INLET METEOROLOGICAL CONDITIONS** (6.6.1, 6.6.6):	INLET HEATING (7.7.2.9.4.1) ☐ FOD SCREEN (7.7.2.1.7)
4	○ WIND SPEED & DIRECTION ______ MPH	INLET PLENUM WINDOW (7.7.1.12)
5	○ SEE ATTACHED WIND ROSE	○ INLET DUCTWORK INTERFACE POINTS (7.7.1.4.1)
6	○ RAINFALL MAX RATE ______ in./hr	______
7	○ SNOWFALL MAX RATE ______ in./hr	______
8	○ FOG OR MIST CONDITIONS	○ OFFSHORE MIN AIR ENTRANCE HEIGHT (7.7.2.3.20) ______ ft
9	○ ICING CONDITIONS	SELF-CLEANING (7.7.2.3.21) ○ ISOLATION VALVES (7.7.2.4.3)
10	REMARKS ______	○ RELATIVE HUMIDITY SENSOR (7.7.2.4.7)
11	______	☐ HIGH VELOCITY INLET SYSTEM
12		FINAL ELEMENT FILTER CLASS (7.7.2.3.5) ______
13	**CHEMICAL CONTAMINANTS IN THE AIR** (6.6.7): (PPMV)	☐ ADDITIONAL VANE SEPARATOR (7.7.2.2.4)
14	○ SODIUM (Na) ______	FILTER MFR. ______ MODEL ______
15	○ POTASSIUM (K) ______	☐ MAINTENANCE INTERVAL ______ MONTHS
16	○ CALCIUM (Ca) ______	INLET FILTERS REPLACEABLE DURING OPERATION (7.7.2.6.1)
17	○ CHLORIDE (Cl) ______	☐ MANOMETER MFR ______ MODEL ______
18	○ SULPHATE (SO_4) ______	RANGE ______ in. H_2O
19	○ NITRATE (NO_3) ______	☐ DUCTING GAUGE / MATERIAL ______ / ______
20	○ TRACE METALS (V, Pb, Ni, Zn) ______	☐ EXPANSION JOINT MFR ______ TYPE ______
21	○ SULPHUR DIOXIDE (SO_2) ______	EXPANSION JOINT SOUND-ABSORBING MATERIAL PROVISIONS (7.7.1.15)
22	○ AMMONIA (NH_3) ______	○ COMBUSTION AND VENT. AIR INTAKE GAS DETECTORS (7.7.2.1.4,7.8.3.13)
23	○ NITROUS OXIDES (NO_X) ______	○ FILTER HOUSE LIGHTING ON UPS (7.7.2.3.17.c)
24	○ HYDROCARBONS (VOC) ______	○ ONLINE GAS TURBINE WASH SYSTEM (7.7.2.10.2)
25	○ HYDROGEN SULFIDE (H_2S) ______	○ NUMBER OF WASH SKIDS (7.7.2.10.3)
26	○ CHLORINE GAS (Cl_2) ______	______ PORTABLE CARTS ______ FIXED WASH SKIDS
27	○ HYDROCHLORIC ACID (HCl) ______	☐ CLEANING FREQUENCY ______ DAYS
28	○ NEON (Ne) ______	REMARKS ______
29	○ OZONE (O_3) ______	______
30	○ HELIUM (He) ______	______
31	○ METHANE (CH_4) ______	______
32	○ KRYPTON (Kr) ______	
33	○ HYDROGEN (H_2) ______	**INLET SILENCERS** (7.7.2.7):
34	○ NITROUS OXIDE (N_2O) ______	SILENCER MFR ______ Δ P ______ in. H_2O
35	○ CARBON MONOXIDE (CO) ______	☐ SILENCER MATERALS ______
36	○ XENON (Xe) ______	**INLET COOLER TYPE**:
37	○ NITROGEN DIOXIDE (NO_2) ______	○ WETTED-MEDIA (7.7.2.9.2.2.1) ○ ATOMIZING SPRAY (7.7.2.9.2.3.1)
38	**PARTICULATE CONTAMINANTS IN AIR** (6.6.8):	○ HEAT EXCHANGER (7.7.2.9.3.1)
39	○ SEAWATER ______	COOLANT-SIDE CONDITIONS (7.7.2.9.3.5):
40	○ COASTAL WATER ______	MAX. AVAILABLE FLOW (L/MIN) ______
41	○ ROADS WITH HEAVY TRAFFIC ______	MAX. TEMP (°F) ______ MIN TEMP (°F) ______
42	○ DRY LAKE BED ______	MAX. PRESS. (PSI) ______ MIN. PRESS. (PSI) ______
43	○ NEARBY COOLING TOWER ______	COOLANT COMPOSITION OR ANALYSIS ______
44	○ PETROCHEMICAL INDUSTRY ______	☐ EXCHANGER MFR ______
45	○ FOSSIL FIRED POWER PLANT ______	☐ MODEL ______ Δ P ______ in. H_2O
46	○ GENERAL CHEMICAL INDUSTRY ______	
47	○ PAPER AND PULP INDUSTRY ______	**REMARKS** ______
48	○ CEMENT PRODUCTION ______	______
49	○ QUARRIES ______	______
50	○ AGRICULTURAL ACTIVITIES ______	______
51	○ PRODUCTION OF FERTILIZERS ______	
52	○ MINING AND METALLURGICAL ACTIVITIES	

1	**ACCESSORIES SUPPLIED BY GAS TURBINE MANUFACTURER**	
2	**EXHAUST SYSTEM** (7.7.3)	**ATMOSPHERIC EMISSIONS (SEE ALSO PAGE 2)**
3	☐ EXPANSION JOINT MFR ____ TYPE ____	**EMISSIONS REDUCTION METHOD** (7.9.6.2)
4	**HEAT RECOVERY SYSTEM**	○ WATER INJECTION ○ SCR (7.9.6.3)
5	○ RELIEF VALVE ○ DIVERSION VALVE	○ STEAM ☐ DRY LOW EMISSIONS
6	○ ATMOSPHERIC RELIEF DEVICE (7.7.3.3.2)	○ OTHER ____
7	○ TYPE ____ MFR ____	**APPLICABLE EMISSION CODES OR REGULATIONS**
8	☐ HEAT RECOVERY DEVICE TYPE ____	○ EPA - TITLE 40 - CFR ○ OTHERS ____
9	○ MFR ____ ΔP ____ in. H_2O	**EMISSION LEVEL (7.9.6.5)**
10	○ HEAT RECOVERY STEAM GENERATOR	○ INSTANTANEOUS (PPMV) ○ ANNUAL RATE (tons/yr)
11	RATE ____ lbm/hr PRESS ____ PSIg TEMP ____ °F	REMARKS ____
12	○ EXHAUST SILENCER PLATE MATERIAL (7.7.3.2.2)	
13	____	
14	○ EXHAUST DUCTWORK INTERFACE POINTS (7.7.1.4.1)	
15	____	
16	☐ SILENCER ____ Δ P ____ in. H_2O	
17	☐ DUCTING GAUGE / MATERIAL ____ / ____	
18	○ EMISSIONS TEST PORTS (7.7.3.3.3) ____	
19	○ EMISSION CONTROL SYSTEM ____	
20	○ EXTENT OF FURNISHED INSULATION (SEE SKETCH) (7.8.1.3)	
21	○ EXHAUST STACK MTL. ____	
22	○ MANOMETER MFR ____	
23	MODEL ____ RANGE ____ in. H_2O	
24		
25		
26	**FIRE PROTECTION** (7.8.3)	
27	**FIRE EXTINGUISHING SYSTEM** (7.8.3.2)	
28	○ NFPA 2001 CLEAN AGENT ○ NFPA 2010 AEROSOL	
29	○ NFPA 750 WATER MIST ○ ISO 14520 CLEAN AGENT	
30	○ NFPA 12 CARBON DIOXIDE ○ ISO 6183 CARBON DIOXIDE	
31	○ MANUAL ACTUATION (7.8.3.4.a)	
32	○ CONTROL ROOM ACTUATION (7.8.3.4.b)	
32A	**TYPE OF DETECTOR** (7.8.3.7) QUANTITY	
33	○ ULTRAVIOLET ____	
34	○ INFRARED ____	
35	○ HEAT RISE (REQUIRED) ____	
36	**GAS DETECTION SYSTEM** (7.8.3.9)	
37	○ NFPA 72	
38	○ IEC 60079-29-1 and IEC 60079-29-2	
39	**REMARKS:** ____	
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COMBUSTION GAS TURBINE (API 616-6th)		REV
	JOB NO. ______ ITEM NO. ______	
DATASHEET US CUSTOMARY UNITS	REVISION ______ DATE ______ PAGE 18 OF ______ BY ______	

INSPECTION AND TESTING; CONTROLS AND INSTRUMENTATION (8.1.1)

SHOP INSPECTION AND TESTS:	REQ	WIT	OBS
CLEANLINESS PRIOR TO ASSEMBLY (8.2.3.3)	○	○	
HYDROSTATIC (8.3.2)		○	○
GAS FUEL SYSTEM PNEUMATIC TEST (8.3.3.1)	○	○	○
MECHANICAL RUN TEST (MRT) (8.3.4)		○	○
ON BASE AUX SYSTEMS INCL IN MRT (8.3.4.1.10)	○	○	○
JOB AUX SYSTEMS INCL IN MRT (8.3.4.2.10)	○	○	○
○ CONTRACT CPLG ○ IDLING ADAPTOR(S)			
○ CONTRACT VIBRATION PROBES			
POLAR VIBRATION PLOTS (8.3.4.3.6.a)	○		
COPY OF VIB DATA (8.3.4.3.8)	○		
SPARE ROTOR IN MRT (8.3.4.2.9)		○	○
PERFORMANCE TEST (8.3.5.1)	○	○	○
○ ISO 2314 ○ ASME PTC			
COMPLETE UNIT TEST (8.3.5.2.1)	○	○	○
FUEL CHANGEOVER TESTS (8.3.5.2.7.a)	○	○	○
STARTS WITH SITE FUEL (8.3.5.2.7.b)	○	○	○
TORSIONAL VIBRATION (8.3.5.2.3)	○	○	○
SOUND PRESSURE LEVEL TEST (8.3.5.3.1)	○	○	○
SOUND POWER LEVEL TEST (8.3.5.3.2)	○	○	○
ROTOR OVERSPEED TEST (8.3.5.4)	○	○	○
AUXILIARY EQUIPMENT TEST (8.3.5.5)	○	○	○
VENTILATION SYSTEM VALIDATION (8.3.5.6)	○	○	○
ENCLOSURE LEAK TEST (8.3.5.7)	○	○	○
GAS TURBINE POST TEST INSPECTION (8.3.5.8)	○	○	○
HYDRAULIC COUPLING HUB/SHAFT FIT (8.3.5.9)	○	○	○
GEN GOV RESPONSE TEST (8.3.5.2.8)	○	○	○
GOV RESPONSE TIME RECORDED (8.3.5.10.1)	○		
OVERSPEED RESP TIME RECORDED (8.3.5.10.2)	○		
SPARE PARTS TEST (8.3.5.11)	○	○	○
FIRE PROTECTION TEST (8.3.5.12)	○	○	○
UNIT CONTROL PANEL FAT (8.3.7)	○	○	○
OTHER TESTS AND INSPECTIONS (8.3.5.13)	○ SEE ATTACHED		
GT FIELD PERFORMANCE TEST (8.3.6)	○	○	○
FIT UP & ASSEMBLY OF PARTS (8.4.9)		○	○

○ SUCCESSFUL PRELIM TESTS PRIOR TO WITNESSED TESTS (8.1.8.2)

INSPECTOR'S CHECKLIST VERIFIED BY (8.1.6)

○ PURCHASER ○ VENDOR

REMARKS: ______

MATERIALS INSPECTION REQUIREMENTS

- ○ PARTS REQUIRING RADIOGRAPHY TEST, SEE ATTACHED LIST (8.2.1.3)
- ○ PARTS REQUIRING MAGNETIC PARTICLE TEST, SEE ATTACHED LIST (8.2.1.3)
- ○ PARTS REQUIRING LIQUID PENETRANT TEST, SEE ATTACHED LIST (8.2.1.3)
- ○ PARTS REQUIRING ULTRASONIC TEST, SEE ATTACHED LIST (8.2.1.3)
- ○ 100% WELD INSPECTION (6.24.6.1) ○ X-RAY ○ MAG ○ LPI
- ○ WELDING HARDNESS TESTING (8.2.3.4)
- ○ PMI (6.20.17.a through m)
- ○ PMI ADDITIONAL COMPONENTS (6.20.17.n), SEE ATTACHED LIST
- ○ CONNECTION DRAWINGS (6.24.6.4)

MISCELLANEOUS INSPECTION AND TESTING:

- ○ VENDOR REVIEW & COMMENTS ON PIPING & FOUNDATION (6.5.10.a)
- ○ SUPPLIER TO OBSERVE PARTING OF FLANGES (6.5.10.b)
- ○ SUPPLIER CHECK ALIGNMENT AT OPERATING TEMPERATURE (6.5.10.c)
- ○ SUPPLIER WITNESS INITIAL ALIGNMENT CHECK (6.5.10.d)
- ○ LIST OF DATA TO KEEP 20 YRS (8.2.1.1.a, 8.2.1.1.g), SEE ATTACHED LIST

VENDOR'S DATA:

- ○ DATA TRANSMITTAL IDENTIFIER (9.1.3) ______
- ○ NUMBER OF PROPOSAL HARDCOPY (9.2.1.a) ______
- ○ SPARE PARTS OPTIMIZATION ANALYSIS (9.2.3.2.w)
- ○ FAILURE MODES AND EFFECTS ANALYSIS (9.2.3.2.x)
- ○ LIFECYCLE ANALYSIS (9.2.3.2.y) ○ DISCOUNT RATE ______ %

PERFORMANCE CURVES (9.2.4)

- ○ SPEED-TORQUE CURVE OF OUTPUT SHAFT (9.2.4.4.a)
- ○ INCREMENTAL POWER FOR STEAM/WATER (9.2.4.4.b)
- ○ EFFECTS OF AIR TEMPERATURE ON EXHAUST FLOW (9.2.4.4.c)
- ○ RUN DOWN CURVES (9.2.4.4.d)
- ○ AIR EMISSIONS (9.2.4.4.e)

○ NUMBER OF CONTRACT DATA HARDCOPIES (9.3.1.6) ______

SOFTCOPY DRAWING FORMAT (9.3.2.4)

○ PDF ○ NATIVE CAD ○ OTHER ______

SOFTCOPY IOM MANUAL FORMAT (9.3.6.1.c)

○ PDF ○ OTHER ______

REMARKS: ______

Annex B
(normative)

Gas Turbine Vendor Drawing and Data Requirements (VDDR)

GAS TURBINE VENDOR DRAWING AND DATA REQUIREMENTS	JOB NO. ____ ITEM NO. ____
	PURCHASE ORDER NO. ____ DATE ____
	REQUISITION NO. ____ DATE ____
	INQUIRY NO. ____ DATE ____
	PAGE 1 OF 2 BY ____
FOR ____	REVISION ____
SITE ____	UNIT ____
SERVICE ____	NO. REQUIRED ____

Proposal [a] Bidder shall furnish ____ copies of data for all items indicated by an X.

Review [b] Vendor shall furnish ____ copies and ____ transparencies of drawings and data indicated.

Final [c] Vendor shall furnish ____ copies and ____ transparencies of drawings and data indicated.
Vendor shall furnish ____ operating and maintenance manuals.

DISTRIBUTION RECORD

Final—Received from Vendor
Final—Due from Vendor [c]
Review—Returned to Vendor
Review—Received from Vendor
Review—Due from Vendor [c]

Proposal	Review	Final	DESCRIPTION	Review—Due from Vendor	Review—Received from Vendor	Review—Returned to Vendor	Final—Due from Vendor	Final—Received from Vendor
			1. Certified dimensional outline drawing and list of connections					
			2. Cross-sectional drawing and bill of materials					
			3. Rotor assembly drawings and bills of materials					
			4. Thrust bearing assembly drawing and bill of materials					
			5. Journal bearing assembly drawings and bills of materials					
			6. Shaft coupling assembly drawings and bills of materials					
			7. Bleed-air/cooling-air sealing and leak-off schematics and bills of materials					
			8. Fuel system schematics and bills of materials					
			9. Fuel system component assembly drawings and lists of connections					
			10. Lube oil/control oil schematics and bills of materials					
			11. Lube oil, control oil, online water washing and offline water washing system, and arrangement drawings					
			12. Electrical and instrumentation schematics and bills of materials					
			13. Electrical and instrumentation arrangement drawings and lists of connections					
			14. Governor, control, and trip system data					
			15. Injection system schematic and bill of materials (optional)					
			16. Injection system arrangement drawings (optional)					
			17. Tabulation of utility requirements					
			18. Certified curves showing shaft speed vs. power at site rated conditions					
			19. Curve showing ambient temperature vs. site rated power output at rated speed with normal fuel					
			20. Curve showing output power shaft speed vs. torque					
			21. Curves showing incremental power output vs. water or steam system injection rate					
			22. Heat rate correction factors					
			23. Thrust bearing performance data					
			24. Blade vibration analysis data; for new or prototype equipment, blade data shall be reviewed at the vendor's facility					
			25. Lateral critical analysis report					
			26. Torsional critical analysis report					
			27. Transient torsional analysis report					
			28. Allowable flange loadings					
			29. Coupling alignment diagram					
			30. Welding procedures					

[a] Proposal drawings and data do not have to be certified or as-built. Typical data shall be clearly identified as such.
[b] Purchaser will indicate in this column the desired time frame for submission of materials using the nomenclature given at the end of this form.
[c] Bidder shall complete these two columns to reflect his/her actual distribution schedule and shall include this form with his/her proposal.

GAS TURBINE
VENDOR DRAWING AND
DATA REQUIREMENTS

JOB NO. ______ ITEM NO. ______
PAGE 2 OF 2 BY ______
DATE ______ REV NO. ______

Proposal [a] — Bidder shall furnish ____ copies of data for all items indicated by an X.

Review [b] — Vendor shall furnish ____ copies and ____ transparencies of drawings and data indicated.

Final [c] — Vendor shall furnish ____ copies and ____ transparencies of drawings and data indicated.
Vendor shall furnish ____ operating and maintenance manuals.

DISTRIBUTION RECORD

Final—Received from Vendor
Final—Due from Vendor [c]
Review—Returned to Vendor
Review—Received from Vendor
Review—Due from Vendor [c]

Proposal	Review	Final	DESCRIPTION	Review—Due from Vendor	Review—Received from Vendor	Review—Returned to Vendor	Final—Due from Vendor	Final—Received from Vendor
			31. Certified hydrostatic test logs					
			32. Mechanical running test logs					
			33. Performance test logs and report					
			34. Nondestructive test procedures and acceptance criteria					
			35. Manufacturing inspection and test plans and test procedures					
			36. Certified mill test reports					
			37. Rotor balancing logs					
			38. Rotor combined mechanical and electrical runout					
			39. As-built datasheets					
			40. As-built dimensions and data					
			41. Installation manual					
			42. Operating and maintenance manuals					
			43. Spare parts recommendations					
			44. Engineering, fabrication, and delivery schedule (progress reports)					
			45. List of drawings					
			46. Shipping lists					
			47. List of special tools furnished for maintenance					
			48. Technical data manual					
			49. Material safety datasheets					
			50. Preservation, packaging, shipping and commissioning procedures					
			51. Bearing Babbitt strength vs. temperature curves					
			52. Noise information					
			53. Pre-commissioning meeting agenda and documentation					
			54. Air filtration system information					
			55. Exhaust flow and temperature vs. inlet air temperature					
			56. Run-down curves showing exhaust flow and temperature vs. time after trip					
			57. NO_x and CO emission curves					

[a] Proposal drawings and data do not have to be certified or as-built. Typical data shall be clearly identified as such.

[b] Purchaser will indicate in this column the desired time frame for submission of materials using the nomenclature given at the end of this f

[c] Bidder shall complete these two columns to reflect his/her actual distribution schedule and shall include this form with his/her proposal.

Notes:

1. Vendor shall send all drawings and data to ______

2. All drawings and data shall show project, appropriation, purchase order, and item numbers in addition to the plant location and unit. In addition to the copies specified above, one set of the drawings/instructions necessary for field installation shall be forwarded with the shipment.

Nomenclature:
S number of weeks before shipment.
F number of weeks after firm order.
D number of weeks after receipt of approved drawings.

Vendor ______
Date ______ Vendor Reference ______
Signature ______
(Signature acknowledges receipt of all instructions)

Descriptions

1) Certified dimensional outline drawing and list of connections, including the following:
   a) size, rating, and location of all purchaser connections;
   b) approximate overall handling weights;
   c) certified maximum single-lift weight;
   d) overall dimensions, maintenance clearances, and dismantling clearances;
   e) shaft centerline height;
   f) enclosure drawings and details;
   g) air inlet system, including inlet silencer, inlet air humidification system (if provided), and inlet air chilling coil (if provided);
   h) exhaust system, including exhaust silencer, waste heat recovery unit (if provided), and bypass stack (if provided);
   i) "ship loose" auxiliary system skids, i.e. water wash system, hydraulic starter system, liquid fuel pump system, gas filter(s) (if provided);
   j) dimensions of baseplates (if furnished) complete with diameter, number and locations of bolt holes and thickness of the metal through which the bolts pass through and recommended clearance; centers of gravity; and details for foundation design;
   k) baseplate FEA or structural analysis for all new baseplate designs and all three-point mount baseplates;
   l) baseplate lifting lug and lifting beam structural analysis and drawings;
   m) direction of rotation.
2) Cross-sectional drawing and bill of materials, including the following:
   a) journal bearing clearances and tolerances;
   b) axial rotor float for all rotors (compressor, gas generator, power turbine);
   c) shaft end and internal labyrinth seal clearances and tolerances;
   d) axial position of rotor disks, blades relative to inlet nozzles or vanes and tolerances allowed;
   e) outside diameter of all disks at the blade tip.
3) Rotor assembly drawings and bills of materials, including the following:
   a) axial position from the active thrust collar face to:
      i) each impeller or rotating disk, inlet side;
      ii) each radial probe;
      iii) each journal bearing centerline;
      iv) phase angle notch;
      v) coupling face or end of shaft;

b) thrust collar assembly details, including:

i) collar shaft with tolerance;

ii) concentricity (or axial runout) tolerance;

iii) required torque for locknut;

iv) surface finish requirements for collar faces;

v) preheat method and temperature requirements for shrunk-on collar installation;

c) dimensional shaft ends for collar faces.

4) Thrust bearing assembly drawing and bill of materials.

5) Journal bearing assembly drawings and bills of materials for all field-maintainable rotors.

6) Shaft coupling assembly drawings and bills of materials, including the following:

a) hydraulic mounting procedure;

b) shaft end gap and tolerance;

c) coupling guards;

d) thermal growth from a baseline of 60 °F (15 °C);

e) manufacturer, size, and serial number;

f) axial natural frequency over allowable spacer stretch (disc-type coupling);

g) balance tolerance;

h) coupling “pull-up” mounting dimensions.

7) Bleed-air/cooling-air sealing and leak-off schematics and bills of materials, including the following:

a) Steady-state and transient air and gas flows and pressures;

b) relief and control valve settings;

c) utility requirements, including electricity, water steam, and air;

d) pipe and valve sizes;

e) instrumentation, safety devices, and control schemes;

f) list of purchaser connections (if any).

8) Fuel system schematics, bills of materials, and data, including the following:

a) fuel compressor/pump performance curves;

b) control valves, relief valves, and instrumentation schematics;

c) vacuum pump schematic, performance curves, cross-section, outline drawing, and utility requirements (if pump is furnished).

9) Fuel system component assembly drawings and lists of connections, including the following:
   a) fuel compressors or pumps;
   b) control and relief valves and instruments;
   c) steam/water injection (if used).
10) Lube oil/control oil schematics and bills of materials, including the following:
    a) steady-state and transient oil flows and pressures at each use point;
    b) control, alarm, and trip settings (pressures and recommended temperatures);
    c) supply temperature and heat loads at each use point at maximum load;
    d) utility requirements, including electricity, water, and air;
    e) pipe and valve sizes;
    f) instrumentation, safety devices, and control schemes.
11) Lube oil, control oil, online water washing and offline water washing system, and arrangement drawings, including size, rating, and location of all purchaser connections.
12) Electrical and instrumentation schematics and bills of materials for all systems, including the following:
    a) starting (direct drive motor or hydraulic) system schematic and bill of materials;
    b) anti-icing system schematic and bill of materials;
    c) gas detection/fire protection schematic and bills of materials;
    d) control system logic diagram;
    e) all schematics shall show all alarm and shutdown limits (set points);
    f) control panel general arrangement drawings.
13) Electrical and instrumentation arrangement drawings and lists of connections, including the following:
    a) control panel elevation drawings;
    b) junction boxes for purchaser interface points.
14) Governor, control, and trip system data, including the following:
    a) firing sequence and final settings;
    b) control and trip settings;
    c) control setting instructions;
    d) governor cross-section and setting instructions.
15) Injection system schematic and bill of materials, including steady-state and transient flows and pressures at each use point.

16) Injection system arrangement drawings, including the size, rating, and location of all purchaser connections.

17) Tabulation of utility requirements, including the following:

  a) lube oil quantity and quality specification;

  b) instrument air;

  c) nitrogen requirements;

  d) water for online and offline washing.

18) Certified curves showing shaft speed vs. power at site rated conditions with normal fuel [see 9.2.4.4 a), Figure 17, Figure 18, or Figure 19). After the order, these curves shall also show any limit on the driven load (such as compressor surge and generator output).

19) Curve showing ambient temperature vs. site rated power output at rated speed with normal fuel over the ambient range specified (see 6.6).

20) Curve showing output power shaft speed vs. torque [include starter if applicable; see 9.2.4.4 a)].

21) Curves showing incremental power output vs. water or steam system injection rate (required only if injection is supplied). See 9.2.4.4 b).

22) Heat rate correction factors for the curves listed in items 18 through 20 and 22 at conditions other than site rated as follows:

  a) ambient pressure to maximum and minimum specified (see 6.6) in increments agreed upon at the time of the order (usually no significant change);

  b) ambient temperature to maximum and minimum specified (see 6.6) in increments agreed upon at the time of the order;

  c) output shaft speed from N_{ma} to N_{mc} in 5 % increments;

  d) exhaust pressure to maximum and minimum specified (see 6.1.24 and 7.7.3.1) in increments agreed upon at the time of the order;

  e) steam or water injection from minimum to maximum flow rate.

23) Curves showing performance of thrust bearing embedded temperature elements as a function of load, shaft speeds, and operating oil supply temperature.

24) Blade vibration analysis data, including the following:

  a) tabulation of all potential excitation sources such as vanes, blades, nozzles, and critical speeds;

  b) Campbell diagram for each stage;

  c) Goodman diagram for each stage.

25) Lateral critical speed analysis report, including, but not limited to, the following:

a) complete description of the method used;

b) graphic display of critical speeds vs. operating speeds;

c) graphic display of bearing and support stiffness and its effect on critical speeds;

d) graphic display of rotor response to unbalance (including damping);

e) journal static loads;

f) stiffness and damping coefficients;

g) tilting-pad bearing geometry and configuration, including:

   i) pad angle (arc) and number of pads;

   ii) pivot offset;

   iii) pad clearance (with journal radius, pad bore radius, and bearing-set bore radius);

   iv) preload.

h) stability analyses.

26) Torsional critical analysis report, including, but not limited to, the following:

   a) complete description of the method used;

   b) graphic display of the mass-elastic solution;

   c) tabulation identifying the mass moment and torsional stiffness of each component identified in the mass-elastic system;

   d) graphic display of exciting forces vs. speed and frequency;

   e) graphic display of torsional critical speeds and deflections (mode-shape diagram);

   f) effects of alternate coupling on the analysis.

27) Transient torsional analysis for all units using synchronous starter/helper motors (mandatory) or driving synchronous generators (optional).

28) Allowable flange loadings for all purchaser connections, including anticipated thermal movements referenced to defined points.

29) Coupling alignment diagram, including recommended limits during operation.

30) Welding procedures for fabrication and repair.

31) Certified hydrostatic test logs.

32) Mechanical running test logs, including, but not limited to, the following:

a) oil flows, pressures, and temperatures;

b) vibration, including an x-y plot of amplitude and phase angle vs. revolutions per minute during startup and coast down;

c) bearing metal temperatures;

d) observed critical speeds (for flexible rotors);

e) exhaust gas temperature;

f) digital recordings of real-time vibration data (see 8.3.4.3.6).

33) Performance test logs and report in accordance with ASME PTC 22 as supplemented by ASME PTC 1.

34) Nondestructive test procedures and acceptance criteria as itemized on the purchase order datasheets on the VDDR form.

35) Manufacturing inspection and testing plans and procedures, including the following:

a) inspection plans;

b) test plans;

c) test procedures for standard, special, or optional tests (see 8.3.5).

36) Certified mill test reports of items as agreed upon in the pre-commitment or inspection meetings.

37) Rotor balancing logs, including a residual unbalance report in accordance with Annex C.

38) Rotor combined mechanical and electrical runout in accordance with 6.14.1.10.4.2 and 6.16.6.2.7.

39) As-built datasheets, including the following:

a) API 616 datasheets;

b) API 614 datasheets;

c) API 613 datasheets (if load gear is provided);

d) ISA instrument datasheets.

40) As-built dimensions (including nominal dimensions with design tolerances) and data for the following listed parts:

a) shaft or sleeve diameters at:

i) thrust collar (for separate collars);

ii) each seal component;

iii) each wheel (for stacked rotors) or bladed disk;

iv) each interstage labyrinth;

v) each journal bearing;

b) each wheel or disk bore (for stacked rotors) and outside diameter;

c) each labyrinth or seal-ring bore;

d) thrust collar bore (for separate collars);

e) each journal bearing inside diameter;

f) thrust bearing concentricity (axial runout);

g) metallurgy and heat treatment for:

   i) shaft;

   ii) impellers or bladed disks;

   iii) thrust collar;

   iv) blades, vanes, and nozzles.

41) Installation manual describing the following (see 9.3.6.2):

a) storage procedures;

b) foundation plan;

c) grouting details;

d) setting equipment, rigging procedures, component weights, and lifting diagrams;

e) coupling alignment diagram [per item 29) above];

f) piping recommendations, including allowable flange loads;

g) composite outline drawings for the driver/driven equipment train, including anchor bolt locations;

h) dismantling clearances;

i) weights, dimensions, and center of gravity for each item to be lifted (e.g. inlet and exhaust system components).

42) Operating and maintenance manuals describing the following (see 9.3.6.3):

a) startup;

b) normal shutdown;

c) emergency shutdown;

d) operating limits (see 6.16.1.4), other operating restrictions, and list of undesirable speeds (see 6.16.1.4);

e) lube oil recommendations and specifications;

f) operational procedures, including recommended inspection schedules, locations, procedures, and acceptance criteria [see 6.5.6 e)];

g) disassembly and reassembly instruction for the following:

i) rotor in casing;

ii) rotor unstacking and restacking procedures;

iii) journal bearings (for tilting-pad bearings, the instructions shall include “go/no-go” dimensions with tolerances for three-step plug gauges);

iv) thrust bearings;

v) seals (including maximum and minimum clearances);

vi) thrust collar;

vii) wheel reblading procedures;

viii) borescope procedures;

ix) fastener torque values;

h) performance data, including:

i) curve showing certified shaft speed vs. site rated power;

ii) curve showing ambient temperature vs. site rated power;

iii) curve showing output-power shaft speed vs. torque;

iv) curve showing incremental power output vs. water or steam injection rate (optional);

v) heat rate correction factors (optional);

vi) thrust bearing performance data;

i) vibration data, per item 24 through item 27 above;

j) as-built data, including:

i) as-built datasheets;

ii) as-built dimensions or data, including assembly clearances;

iii) hydrostatic test logs, per item 31 above;

iv) mechanical running test logs, per item 32 above;

v) rotor balancing logs, per item 37 above;

vi) rotor mechanical and electrical runout at each journal, per item 38 above;

vii) physical and chemical mill certificates for critical components;

viii) test logs of all optional tests;

k) drawings and data, including:

  i) certified dimensional outline drawing and list of connections;

  ii) cross-sectional drawing and bill of materials;

  iii) rotor assembly drawings and bills of materials;

  iv) thrust bearing assembly drawing and bill of materials;

  v) journal bearing assembly drawings and bills of materials;

  vi) seal component drawing and bill of material;

  vii) lube oil schematics and bills of materials;

  viii) lube oil arrangement drawing and list of corrections;

  ix) lube oil component drawings and data;

  x) electrical and instrumentation schematics and bills of materials;

  xi) electrical and instrumentation arrangement drawings and list of connections;

  xii) governor, control, and trip system drawings and data;

  xiii) trip and throttle valve construction drawings;

l) operating and maintenance procedures.

43) Spare parts list with stocking level recommendations, in accordance with 9.3.5, including the following:

  a) commissioning spares;

  b) startup spares;

  c) 2-year's operating spares;

  d) insurance capital spares.

44) Progress reports and delivery schedule, including vendor buyouts and milestones. The reports shall include engineering, purchasing, manufacturing, and testing schedules for all major components. Planned and actual dates and the percentage completes shall be indicated for each milestone in the schedule.

45) List of drawings, including latest revision numbers and dates.

46) Shipping list, including all major components that will ship separately.

47) List of special tools furnished for maintenance (see 7.11).

48) Technical data manual, including the following:

a) as-built purchaser datasheets, per item 39 above;

b) certified performance curves, per item 18 through item 22 above;

c) drawings, in accordance with 9.3.2;

d) as-built assembly clearances;

e) spare parts list, in accordance with 9.3.5;

f) utility data, per item 17 above;

g) blade vibration data, per item 24 above;

h) reports, per items 25, 26, 27, 29, 31, 32, 33, 37, and 38 above.

49) Material safety datasheets (OSHA Form 20).

50) Preservation, packaging, shipping, and commissioning procedures, including the following:

a) painting specification;

b) preservation specification and procedures applicable from site arrival to startup;

c) export boxing details along with proper lifting procedures;

d) commissioning procedures for cleaning and flushing of lube oil, hydraulic oil, and fuel systems.

51) Bearing Babbitt strength vs. temperature curves.

52) Noise information, including the following:

a) inlet system noise spectrum;

b) gas turbine enclosure noise spectrum;

c) exhaust system noise spectrum.

53) Pre-commissioning meeting agenda and documentation.

54) Air filtration system information (see 7.7.2.2.6 and 7.7.2.9.4.11).

55) Exhaust flow and temperature vs. inlet air temperature [see 9.2.4.4 c)].

56) Run-down curves showing exhaust flow and temperature vs. time after trip [see 9.2.4.4 d)].

57) NO_X and CO emission curves [see 9.2.4.4 e)].

Annex C
(normative)

Procedure for the Verification of Residual Unbalance

C.1 General

This annex describes a procedure to verify residual unbalance in rotors by determining the calibration accuracy of the balancing equipment. Balancing machines may be configured to display the amount of rotor unbalance; however, the calibration can be in error. To determine the actual residual unbalance, a known amount of unbalance should be added using an appropriate procedure.

C.2 Residual Unbalance

Residual unbalance is the amount of unbalance remaining in a rotor after balancing. Residual unbalance shall be expressed in g mm (g-in.).

C.3 Maximum Allowable Residual Unbalance

C.3.1 The maximum allowable residual unbalance, per plane, shall be calculated in accordance with Equation (C.1).

C.3.2 The static weight on each journal shall be determined by rotordynamic calculations. If the static loadings cannot be obtained from rotordynamic calculations then the method by which the journal weight was determined shall be identified. It should NOT be assumed that rotor weight is equally divided between the two journals. There can be great discrepancies in the journal weight to the point of being very low (even negative on overhung rotors).

C.4 Residual Unbalance Check

C.4.1 General

C.4.1.1 When the balancing machine readings indicate that the rotor has been balanced within the specified tolerance, a residual unbalance check shall be performed before the rotor is removed from the balancing machine. Record and plot the indicated residual unbalance heavy spot of both planes on the Residual Unbalance Worksheet (one for each plane).

NOTE Due to the possibility of machine calibration errors, the residual unbalance check can be performed prior to final correction of the unbalance, typically after the placement of temporary weights.

C.4.1.2 To check the residual unbalance, a known trial weight, equal to the multiplier from Table C.1 times the maximum allowable unbalance from Equation (C.1), is attached to the rotor at the same angular location as the indicated heavy spot. The check is run at each balance machine readout plane, and the readings in each plane are tabulated. This run is then repeated with the weight placed 180° opposite of the heavy spot at the same radius. The check is run at each balance machine readout plane, and the readings in each plane are tabulated.

Table C.1—Trial Weight Multiplier vs. N_{mc}

Maximum Continuous Speed of Part/Assembly	Trial Weight Multiplier
$N_{mc} \leq 7500$ rpm	1.5
$7500 < N_{mc} \leq 12{,}500$ rpm	2.0
$N_{mc} > 12{,}500$ rpm	2.5

C.4.2 Procedure

C.4.2.1 Select a trial weight and radius that will be equivalent to the trial weight multiplier times the maximum allowable residual unbalance as defined by Equation (C.1).

NOTE If U_r is 488.4 g mm (19.2 g-in.), for a rotor with MCS ≤ 7500 rpm, the trial weight magnitude should equal 732.6 g mm (28.8 g-in.).

In g mm units:

$$U_r = 6350 \frac{W}{N_{mc}} \qquad \text{(for } N_{mc} < \text{25k rpm)} \qquad \text{(C.1a)}$$

$$U_r = \frac{W}{3.937} \qquad \text{(for } N_{mc} \quad \text{25k rpm)}$$

In g-in. units:

$$U_r = 113.4 \frac{W}{N_{mc}} \qquad \text{(for } N_{mc} < \text{25k rpm)} \qquad \text{(C.1b)}$$

$$U_r = \frac{W}{220.46} \qquad \text{(for } N_{mc} \quad \text{25k rpm)}$$

C.4.2.2 At the heavy spot, add the first trial weight at the selected radius in C.4.2.1 to the first balance readout plane. Trial weight magnitude is a linear function with radial location. Every effort should be made to place the weight accurately, both radially and circumferentially.

C.4.2.3 Verify that the balancing machine's readings are stable without faulty sensors or displays.

NOTE When the trial weight is added to the last known heavy spot, the first meter reading should easily exceed the balance tolerance in that plane. Little or no meter reading generally indicates that the rotor was not balanced to the correct tolerance, the balancing machine was not sensitive enough, or that a balancing machine fault exists (i.e. a faulty pickup).

C.4.2.4 Remove the trial weight and rotate the trial weight to the second position (that is 180° from the initial trial weight position). All verification shall be performed using only one sensitivity range on the balance machine.

C.4.2.5 Record and plot the balancing machine unbalance amplitude and phase readout (heavy spot) on the Residual Unbalance Worksheet for the readout plane in question. If the indicated unbalance phase angle for the residual unbalance (see C.4.1.1) differs by more than 10° from the first trial weight phase angle or the second trial weight phase angle plus 180°, then the angular location of the trial weight should be adjusted to lessen the difference. Once the phase angle difference is less than 10°, the actual amount of residual unbalance (refer to worksheets, Figure C.2 and Figure C.3) can be calculated.

C.4.2.5.1 The difference in magnitudes of each trial weight run relative to the indicated unbalance should be within 20 %.

C.4.2.5.2 If this is exceeded, weight placement and magnitude should be reviewed. A larger trial weight can be used with the value entered into the "User Selected Trial Weight," otherwise this value should be zero.

NOTE 1 Not meeting this tolerance will generate errors in the calculated residual unbalance or indicate a problem with the balance machine.

NOTE 2 In Figure C.3, a larger trial weight was needed to enable the second reading to be 180° different than the indicated reading (basically cross over the center of the plot). The larger trial weight (9 g) was inputted into the "User Selected Trial Weight" cell. This value of the trial weight "TW" is then used to calculate the "Actual Residual Unbalance." For this example, the machine was determined to be reading $^{1}/_{2}$ of the actual unbalance.

C.4.2.6 Repeat the steps described in C.4.2.1 through C.4.2.5 for each balance machine readout plane. If the specified maximum allowable residual unbalance has been exceeded in any balance machine readout plane when calculating the actual residual unbalance, the rotor shall be balanced more precisely and checked for compliance using the calibration factors determined above.

C.4.2.7 For stack component balanced rotors, a residual unbalance check shall be performed after the addition and balancing of the rotor after the addition of the first rotor component and at the completion of balancing of the entire rotor, as a minimum.

NOTE 1 This ensures that time is not wasted and rotor components are not subjected to unnecessary material removal in attempting to balance a multiple component rotor with a faulty balancing machine.

NOTE 2 For large multistage rotors, the journal reactions can be considerably different from the case of a partially stacked to a completely stacked rotor.

Customer:

Job / Project Number:

OEM Equipment S/N:

Rotor Identification Number:

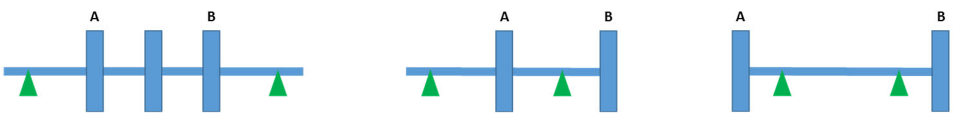
Repair Purchase Order Number:

Vendor Job Number:

Correction Plane (A or B) - see sketch:

Balancing Speed:		rpm		
Maximum Continuous Operating Speed:	**Nmcs**	rpm		
Static Journal Weight Closest to This Plane:	**W**	kg		lbm
W obtained from:		Rotordynamics		Specify if Other
Correction Radius - radius at which the readings are taken and trial weight will be placed:	**R**	mm		in

Balance Plain Description: End A End B



Calculate the Maximum Allowable Residual Unbalance (Ur):

Nmcs ≤ 25000 rpm **Nmcs > 25000 rpm**

SI Units:

$$U_r = \frac{6350 * W}{N_{mcs}} \quad \text{or} \quad U_r = \frac{W}{3.937}$$

Ur g-mm **Unbalance @ Balance Plane** g

Customary Units: **(USC expressed in grams)**

$$U_r = \frac{113.4 * W}{N_{mcs}} \quad \text{or} \quad U_r = \frac{W}{220.46}$$

Ur g-in **Unbalance @ Balance Plane** g

Trial Weight Calculation:

$$TW = \frac{Um * U_r}{R}$$

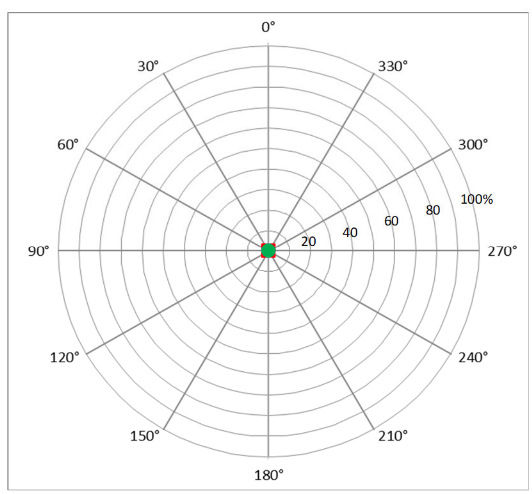
Trial Weight Multiplier (Um):

Recommended Trial Weight: g **User Selected Trial Weight:** 0.00 g

Record Indicated Residual Unbalance (C.4.1.1) and the Indicated Unbalance with Trial Weight (C.4.2.5)

Test Data

Unbalance Readings		**Magnitude grams (g)**		**Phase Angle degrees (°)**	
A: Residual Unbalance (IR)*					
B: Unbalance w/ 1st Trial Weight (Mx)*					
C: Unbalance w/ 2nd Trial Weight (Mn)*					
	Y = Mx - Mn	0.00	**Angle Diff |B-A| <10**	0.00	
	Z = Mx + Mn	0.00	**Angle Diff |C-A| <10**	180.00	
Trial Weight Effect	**R1 = Mx - IR**	0.00	**R2 = Mn + IR**	0.00	
	R1/R2		**R2/R1**		
Uniformity Of Trial Weight Placement & Effect:		***Caution: Potential Inaccuracies***			
Angle diff < 10 and Magnitude ratio [0.8 < (R1/R2 & R2/R1) < 1.2]		*If cautioned, increase weight or adjust weight placement angle*			
		Metric (g-mm)		**Customary (g-in)**	
Residual Unbalance Reading (IR*R)					
Actual Residual Unbalance (AR=R*TW*Y/Z)					
Within Specification (AR < Ur)					



**** denotes indicated values***

Indicated Residual Unbalance

Indicated Unbalance w/ Trial Weight #1

Indicated Unbalance w/ Trial Weight #2

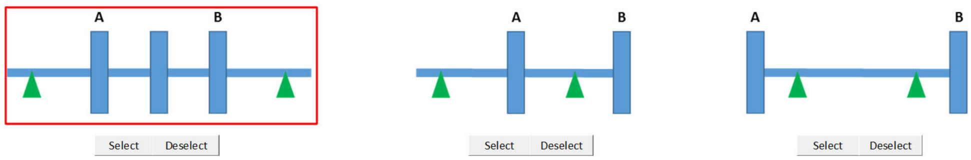
Indicates Input Required

Figure C.1—Residual Unbalance Worksheet

Customer:	International Oil Company
Job / Project Number:	JN 2398-IRG-48
OEM Equipment S/N:	345-687
Rotor Identification Number:	C4784XL
Repair Purchase Order Number:	
Vendor Job Number:	12484-45985
Correction Plane (A or B) - see sketch:	Plane A

Balancing Speed:		400	rpm		
Maximum Continuous Operating Speed:	**Nmcs**	11000	rpm		
Static Journal Weight Closest to This Plane:	**W**	1300	kg		lbm
W obtained from:		Rotordynamics			Specify if Other
Correction Radius - radius at which the readings are taken and trial weight will be placed:	**R**	200	mm		in

Balance Plain Description: Thrust End A Coupling End B



Calculate the Maximum Allowable Residual Unbalance (Ur):

Nmcs ≤ 25000 rpm **Nmcs > 25000 rpm**

SI Units:

$$U_r = \frac{6350 * W}{N_{mcs}} \quad \text{or} \quad U_r = \frac{W}{3.937}$$

Ur 750.45 g-mm **Unbalance @ Balance Plane** 3.75 g

Customary Units: **(USC expressed in grams)**

$$U_r = \frac{113.4 * W}{N_{mcs}} \quad \text{or} \quad U_r = \frac{W}{220.46}$$

Ur g-in **Unbalance @ Balance Plane** g

Trial Weight Calculation:

$$TW = \frac{Um * U_r}{R}$$

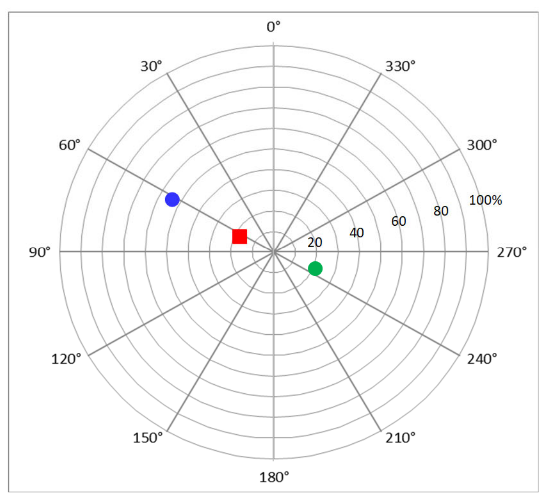
Trial Weight Multiplier (Um): 2

Recommended Trial Weight: 7.50 g **User Selected Trial Weight:** 0.00 g

Record Indicated Residual Unbalance (C.4.1.1) and the Indicated Unbalance with Trial Weight (C.4.2.5)

Test Data

Unbalance Readings		Magnitude grams (g)		Phase Angle degrees (°)	
A: Residual Unbalance (IR)*		3.5		65	
B: Unbalance w/ 1st Trial Weight (Mx)*		10.7		62	
C: Unbalance w/ 2nd Trial Weight (Mn)*		4.2		247	
	Y = Mx - Mn	6.50		Angle Diff |B-A| <10	3.00
	Z = Mx + Mn	14.90		Angle Diff |C-A| <10	2.00
Trial Weight Effect	R1 = Mx - IR	7.20		R2 = Mn + IR	7.70
	R1/R2	0.94		R2/R1	1.07
Uniformity Of Trial Weight Placement & Effect:		Acceptable			
Angle diff < 10 and Magnitude ratio [0.8 < {R1/R2 & R2/R1} < 1.2]		*If cautioned, increase weight or adjust weight placement angle*			
		Metric (g-mm)		Customary (g-in)	
Residual Unbalance Reading (IR*R)		700.00			
Actual Residual Unbalance (AR=R*TW*Y/Z)		654.76			
Within Specification (AR < Ur)		YES			



100% = 20 g

**** denotes indicated values***

Indicated Residual Unbalance

Indicated Unbalance w/ Trial Weight #1

Indicated Unbalance w/ Trial Weight #2

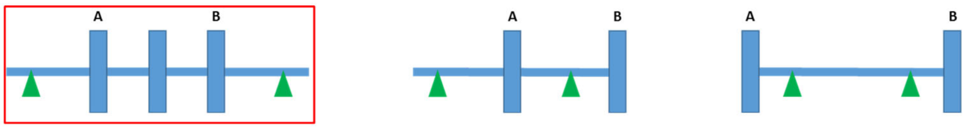
Indicates Input Required

Figure C.2—Sample Residual Unbalance Worksheet for Left Plane (Metric)

Customer:	US Oil Company
Job / Project Number:	JN 2398-IRG-48
OEM Equipment S/N:	345-687
Rotor Identification Number:	C4784XL
Repair Purchase Order Number:	
Vendor Job Number:	12484-45985
Correction Plane (A or B) - see sketch:	Plane B

Balancing Speed:		400	rpm			
Maximum Continuous Operating Speed:	Nmcs	11000	rpm			
Static Journal Weight Closest to This Plane:	W		kg		2866	lbm
W obtained from:		Rotordynamics				Specify if Other
Correction Radius - radius at which the readings are taken and trial weight will be placed:	R		mm		8	in

Balance Plain Description: Thrust End A Coupling End B



Select Deselect Select Deselect Select Deselect

Calculate the Maximum Allowable Residual Unbalance (Ur):

Nmcs ≤ 25000 rpm **Nmcs > 25000 rpm**

SI Units:

$$U_r = \frac{6350 * W}{N_{mcs}} \quad \text{or} \quad U_r = \frac{W}{3.937}$$

Ur		Unbalance @ Balance Plane	
	g-mm		g

Customary Units: **(USC expressed in grams)**

$$U_r = \frac{113.4 * W}{N_{mcs}} \quad \text{or} \quad U_r = \frac{W}{220.46}$$

Ur		Unbalance @ Balance Plane	
29.55	g-in	3.69	g

Trial Weight Calculation:

$$TW = \frac{Um * U_r}{R}$$

Trial Weight Multiplier (Um):	Recommended Trial Weight:		User Selected Trial Weight:	
2	7.39	g	9.00	g

Record Indicated Residual Unbalance (C.4.1.1) and the Indicated Unbalance with Trial Weight (C.4.2.5)

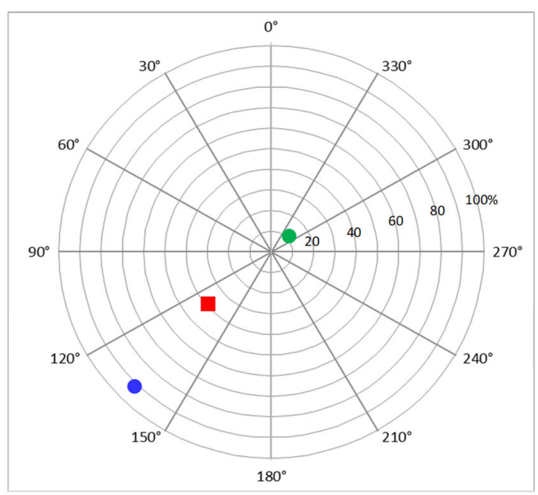
Test Data

Unbalance Readings		Magnitude grams (g)	Phase Angle degrees (°)	
A: Residual Unbalance (IR)*		3.5	130	
B: Unbalance w/ 1st Trial Weight (Mx)*		8.2	135	
C: Unbalance w/ 2nd Trial Weight (Mn)*		1	312	
	Y = Mx - Mn	7.20	Angle Diff |B-A| <10	5.00
	Z = Mx + Mn	9.20	Angle Diff |C-A| <10	2.00
Trial Weight Effect	R1 = Mx - IR	4.70	R2 = Mn + IR	4.50
	R1/R2	1.04	R2/R1	0.96
Uniformity Of Trial Weight Placement & Effect:		Acceptable		
Angle diff < 10 and Magnitude ratio [0.8 < (R1/R2 & R2/R1) < 1.2]		*If cautioned, increase weight or adjust weight placement angle*		
		Metric (g-mm)	Customary (g-in)	
Residual Unbalance Reading (IR*R)			28.00	
Actual Residual Unbalance (AR=R*TW*Y/Z)			56.35	
Within Specification (AR < Ur)			NO	

**** denotes indicated values***

- Indicated Residual Unbalance
- Indicated Unbalance w/ Trial Weight #1
- Indicated Unbalance w/ Trial Weight #2

Indicates Input Required

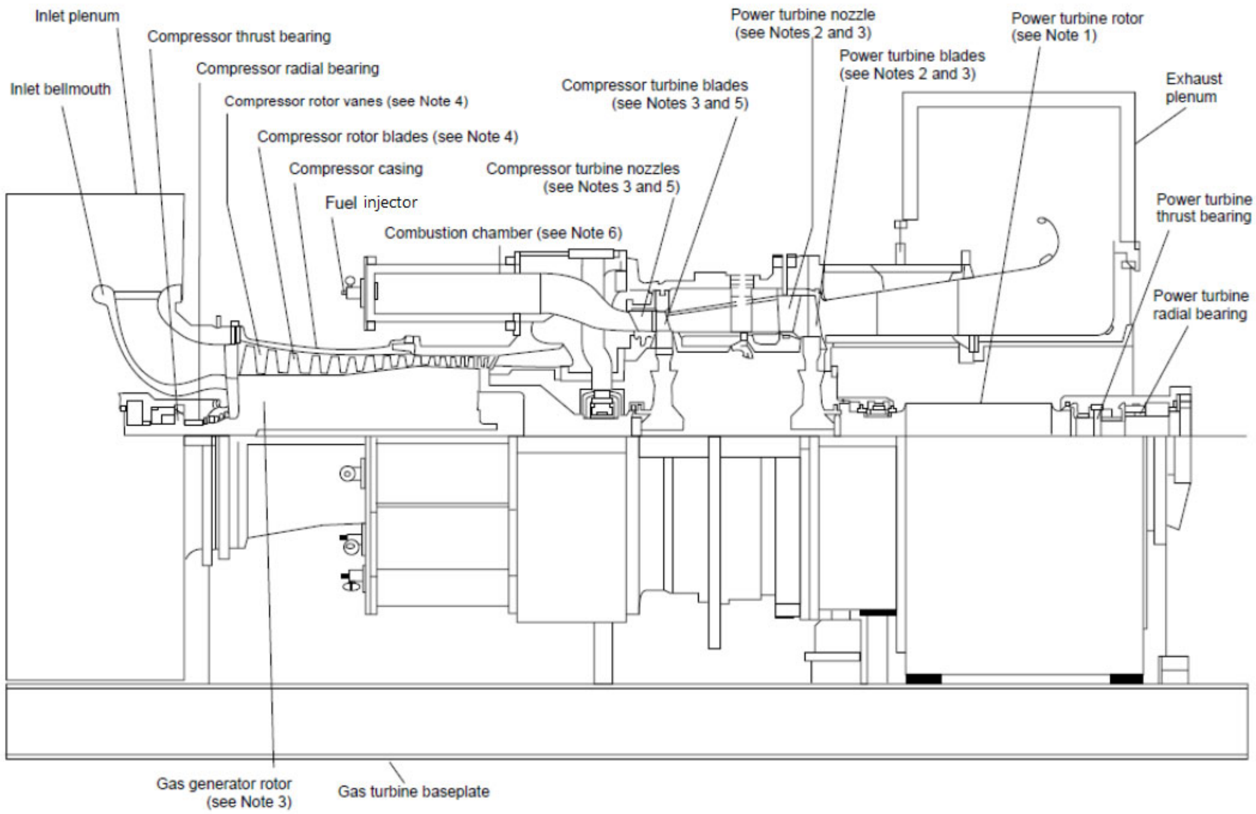


100% = 9 g

Figure C.3—Sample Residual Unbalance Worksheet for Right Plane (USC)

Annex D
(informative)

Gas Turbine Nomenclature



NOTE 1 Gas turbine rotors may be single shaft or multiple shaft (shown).

NOTE 2 Turbines may be single (shown) or multistage.

NOTE 3 Turbines may be axial (shown) or radial flow.

NOTE 4 Compressors may be axial (shown) or radial flow or a combination of both.

NOTE 5 Compressor turbines may be single (shown) or multistage.

NOTE 6 Combustion chambers may be cannular (shown), annular, or a single chamber.

Figure D.1—Industrial Gas Turbine Nomenclature

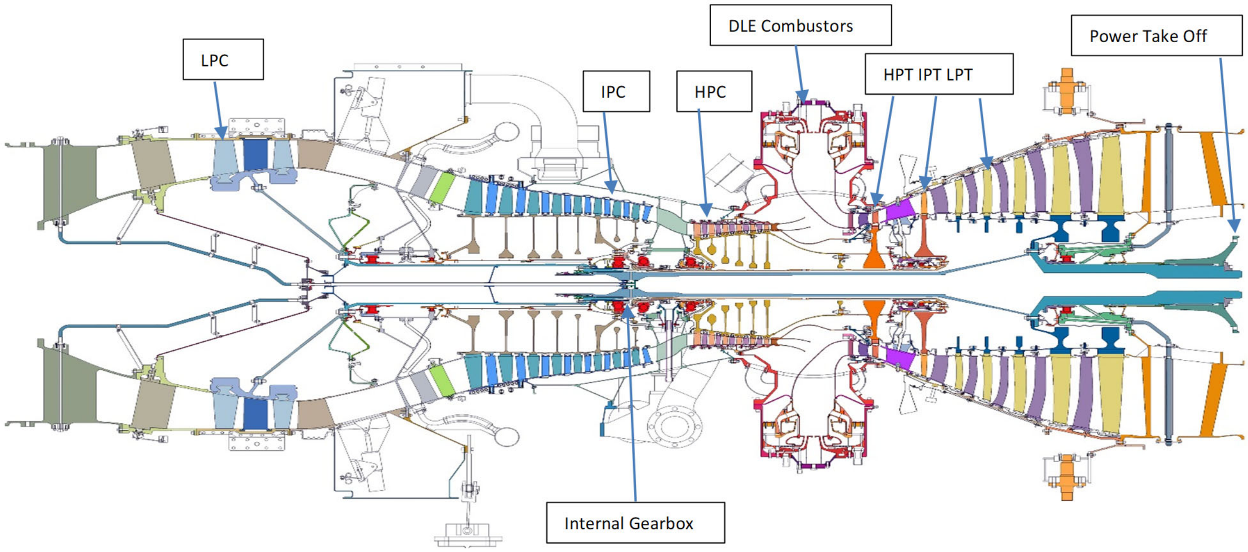


Figure D.2—Three-shaft Aeroderivative Gas Turbine Nomenclature

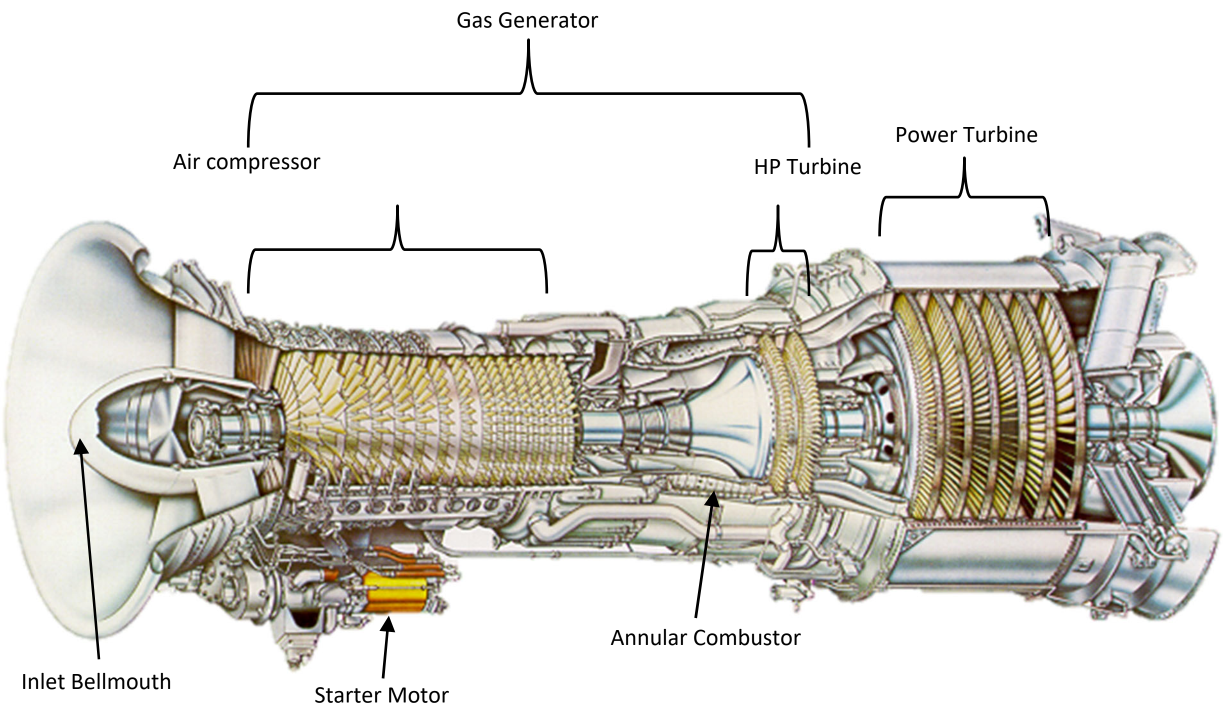


Figure D.3—Two-shaft Aeroderivative Gas Turbine Nomenclature

Annex E
(informative)

Gas Turbine Combustion

E.1 Introduction

The gas turbine is an internal combustion engine. All internal combustion engines create air emissions. Unlike its automotive cousins, the spark ignition (Otto cycle) or the compression ignition (Diesel cycle) engine, the gas turbine uses the Brayton cycle.

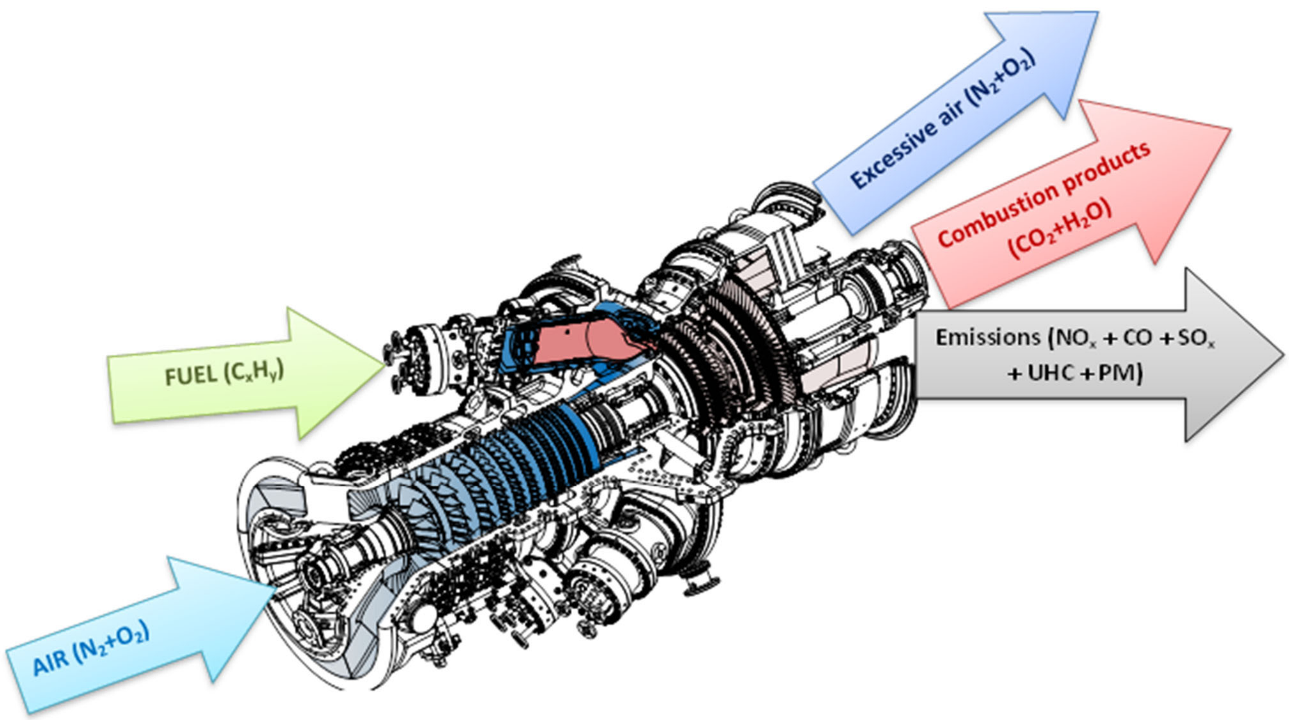


Figure E.1—Schematic of Gas Turbine and Flows

The Brayton cycle uses constant pressure fuel combustion. The combustor discharge is a continuous flow of hot high-pressure gas into the turbine section, where it is expanded to a lower pressure and temperature, causing the turbine to rotate and drive the load.

E.2 Combustion Process

E.2.1 General

The combustion process converts chemical energy from the fuel to thermal energy to drive the turbine. Gas turbine designs use different combustion processes with different characteristics.

E.2.2 Stoichiometric Combustion

Combustion, in the context of the gas turbine, is the reaction of hydrocarbon fuel and oxygen. The oxygen comes from air, which itself is a mixture predominantly of oxygen and nitrogen, i.e. (O_2 + 3.76 N_2). Almost 100 % of the nitrogen passes through without reacting.

For methane, the main component of natural gas:

$$CH_4 + 2\ (O_2 + 3.76\ N_2) \qquad CO_2 + 2\ H_2O + 7.52\ N_2 + \text{Heat} \tag{E.1}$$

For diesel, assumed to be generically $C_{13}H_{28}$:

$$C_{13}H_{28} + 20\ (O_2 + 3.76\ N_2) \qquad 13\ CO_2 + 14\ H_2O + 75.2\ N_2 + \text{Heat} \tag{E.2}$$

When the fuel is combusted in the above proportions [see Equations (E.1) and (E.2)], it is termed "stoichiometric" combustion. All the oxygen and fuel are consumed, and the maximum temperature rise is achieved. If there is excess fuel, i.e. fuel rich combustion, some fuel is not combusted so the maximum temperature is not achieved. On the other hand, if there is excess air or fuel lean combustion, all the fuel is consumed, but the excess air reduces the temperature rise. Tables are available of temperature rise given the fuel-to-air ratio (FAR), fuel composition, and initial air temperature.

E.2.3 Emissions

E.2.3.1 General

Hydrocarbon combustion ideally should produce only water, carbon dioxide and heat. Other emissions can result from combustion. Some emissions can be affected by combustor design and control while others can only be affected by changing the fuel composition. NO_X and CO are usually the most highly regulated emissions.

E.2.3.2 Nitrogen Oxides (NO_X)

NO_X reacts in the atmosphere to form acid rain and smog. NO_X in combination with CO and sunlight can form ground level ozone. NO_X in a gas turbine can come from 3 sources: fuel bound nitrogen, prompt NO_X, and thermal NO_X. The most common compounds are nitrogen oxide (NO) and nitrogen dioxide (NO_2).

Fuel bound nitrogen arises from fuel containing nitrogen atoms or nitrogen bearing compounds, which is typically found in liquid fuels. Nitrogen mixed with gas fuel is not fuel bound nitrogen. When the fuel is combusted, the bound nitrogen atoms are released and will form NO_X by combining with oxygen. Fuel bound nitrogen can only be affected by changing the fuel source. Combustion design and function will not affect fuel bound nitrogen.

Prompt NO_X forms mainly at low temperature when the mixture is fuel rich via the direct reaction of N_2 with hydrocarbon radicals.

Thermal NO_X forms when nitrogen combines with oxygen in the high temperature environment of the combustor. From Figure E.2, reduction of the flame temperature will reduce the production of thermal NO_X; however, CO emissions will be increased. Figure E.2 shows the effect of flame temperature on the production of NO_X and CO.

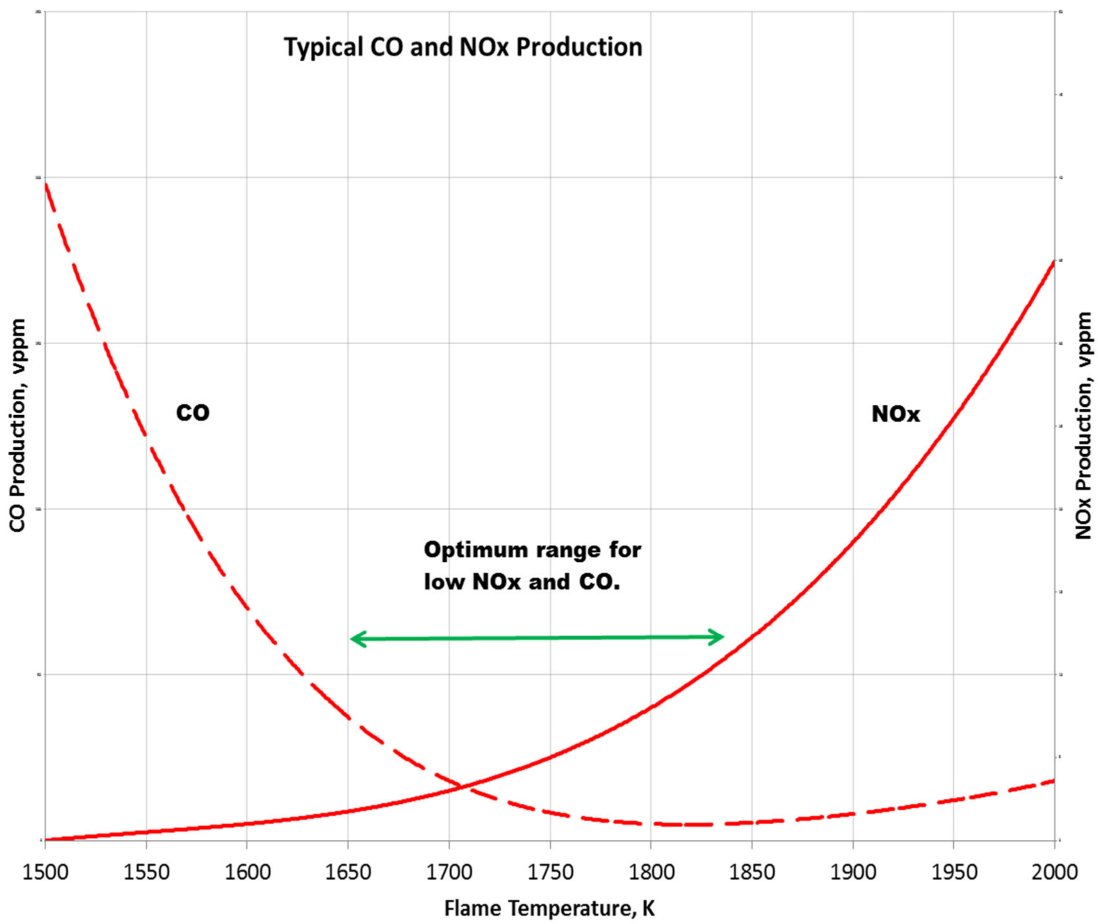


Figure E.2—Diagram Showing NO_X and CO Production with Flame Temperature

E.2.3.3 Carbon Monoxide (CO)

CO is an indication of incomplete combustion. CO in high concentration is harmful to *most* animals (including humans) as it is preferentially absorbed in the bloodstream instead of oxygen. In low concentration, CO reacts in the atmosphere to form photochemical smog. CO in conjunction with NO_X can form ground level ozone.

From Figure E.2, maintaining high combustion temperature will reduce CO emissions but will generate more thermal NO_X.

E.2.3.4 UHC, Smoke, Particulate Matter

UHC, volatile organic compounds (VOC), smoke, particulate matter, and other organic compounds form from incomplete combustion of hydrocarbon fuel.

E.2.3.5 Carbon Dioxide (CO_2)

CO_2 and water are the main emissions from hydrocarbon combustion. CO_2 is a greenhouse gas and in high concentrations can cause asphyxiation by displacing oxygen.

CO_2 emissions can be reduced by using fuels with a high hydrogen to carbon ratio (e.g. methane instead of diesel) and using more efficient gas turbines and processes (e.g. cogeneration and exhaust heat recovery versus a simple-cycle operation).

E.2.3.6 Sulfur Oxides (SO_X) and Trace Metal Oxides

Trace metals and their oxides, e.g. sulfur, mercury, etc. usually cannot be controlled or affected by the gas turbine as they enter with the fuel and leave in the exhaust. These nonhydrocarbon components of the fuel can be affected by appropriate fuel selection and processing.

E.3 Combustor Configurations

E.3.1 General

Gas turbines use a number of different physical configurations of combustors.

E.3.2 Can Combustors

Can combustors, also known as tubular combustors, are cylindrical in shape with fuel injectors at the upstream end. The cylinder wall is pierced with holes to dilute the flame and adjust the exit temperature distribution. One or more can combustors may be used in a gas turbine.

These combustors are relatively easy to design as the can combustors can be tested individually; therefore, only a fraction of the gas turbine air is required for rig testing and development.

Can combustor geometry requires consideration when integrating with the gas turbine. Exhaust from the cylindrical cans has to be joined to the annular turbine section with uniform temperature and pressure distribution. Can combustors are robust but may have higher pressure drop than other configurations and tend to be heavy.

Ignition systems are required for each can combustor. Spark ignitors are fitted into each can combustor or cross fire tubes are used to bring hot gas from one combustor can to light up a neighboring combustor can.

E.3.3 Annular Combustors

Annular combustors (see Figure E.3) typically have a forward, inner and outer walls. The fuel injectors are located at the forward wall, whereas combustion and dilution air is introduced through the inner and outer walls. An annular combustor is usually the most compact design. Ignition is relatively simple as a single ignitor will propagate a flame around the complete combustor.

Design and development of the combustor can be difficult as full gas turbine air and fuel flow are required for testing. However, a sector of the annular combustor may be tested if corrections are applied for the effects of the end walls.

E.3.4 Can Annular Combustors

Can annular combustors are a compromise configuration with a number of can combustors in the upstream portion and an annular configuration downstream. The annulus simplifies achieving a uniform distribution for pressure and temperature entering the turbine section. Compared to an annular combustor, development is easier as a single combustor can be tested using a fraction of the gas turbine air and fuel flow.

Similar to a can combustor design, ignition may use either cross fire tubes or ignitors.

This design is not as compact as an annular combustor.

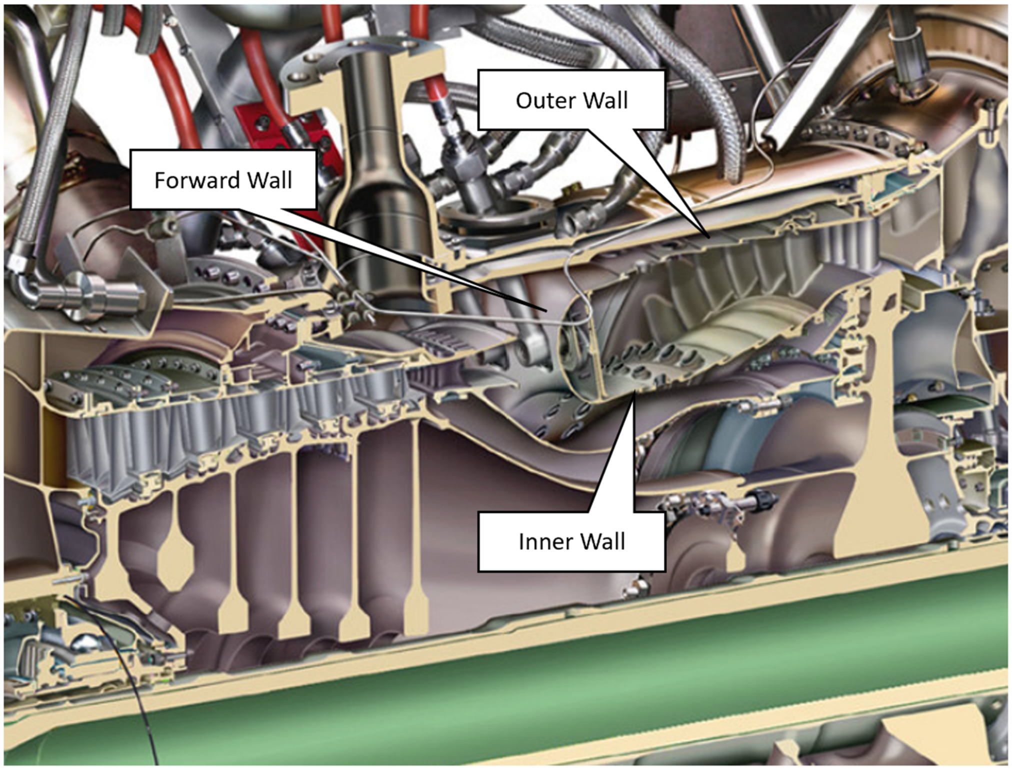


Figure E.3—Annular Combustor

E.4 Combustion Processes

E.4.1 General

Combustors employ different designs to provide stable ignition. Some designs use a swirl stabilized recirculation zone within the combustor, trapped vortex within the combustor, or an intentional flame holder, e.g. a wake behind a bluff structure. A trapped vortex may be fed by the incoming fuel and air mixture or have a separate, dedicated source of fuel and air.

E.4.2 Conventional Combustion

E.4.2.1 General

Conventional combustion (also known as diffusion combustion or nonpremixed combustion) is very stable and may operate reliably from starting to full power. Liquid or gas fuel can be used.

The conventional combustor in its simplest form (see Figure E.4) consists of a liner, a fuel injector, and an igniter. Fuel and air are injected into the combustor where turbulence and diffusion mix the fuel with the air. FAR in the mixing zone ranges from 100 % fuel to 100 % air and the flame will exist where the FAR is within the flammability range. There will be a zone of stoichiometric FAR with maximum flame temperature and highest NO_X emissions. See Figure E.5.

The combustor primary zone is a space into which the fuel is injected along with sufficient air from the compressor to create a near adiabatic and stoichiometric fuel and air mixture. A primary zone designed in this way has high combustion efficiency and stability and is capable of operating stably over the complete operating range of the engine from starting to engine idle and across the load range. The primary zone at full load has to contain a flame temperature of the order of 2500 °C (4500 °F) depending on fuel composition.

E.4.2.2 Liner

Combustor wall and liner cooling (see Figure E.4) is required because currently available materials cannot survive the high combustor gas temperatures. Conventional combustors typically rely on injection of compressor bleed air to stop hot gases from impinging on the metal surfaces (film cooling). Many rows of cooling are included down the walls to continuously refresh the cooling air as it diffuses into the hot gases (see Figure E.4).

Larger dilution holes in the liner inject air deeply into the flame to complete the combustion process and adjust the bulk and local temperature. Adjusting the local gas temperature distribution at the combustor exit is required to prevent turbine blade temperature issues.

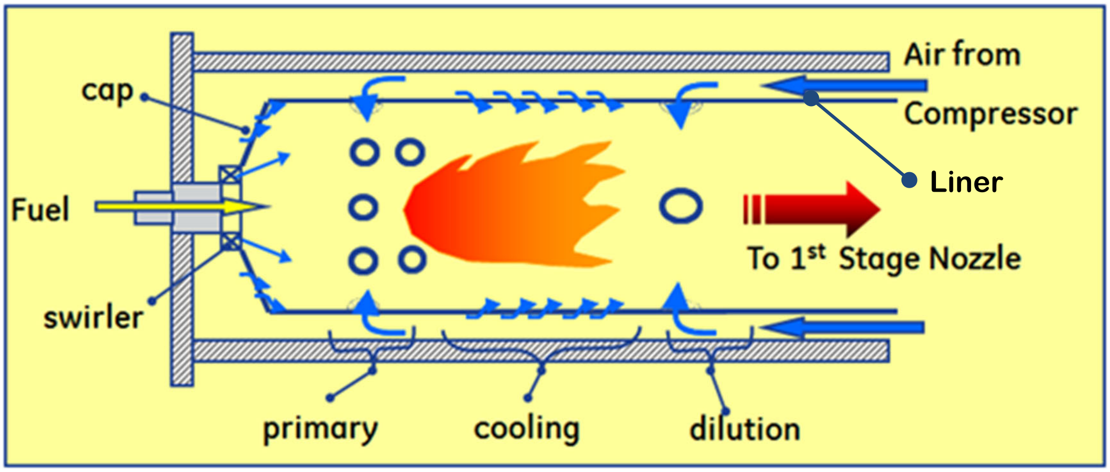


Figure E.4—Diffusion Combustor

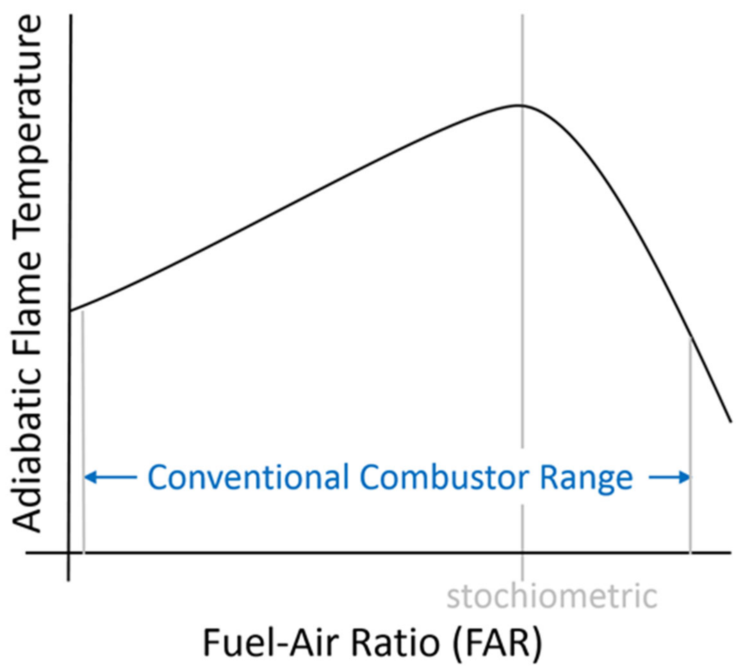


Figure E.5—Conventional Combustor FAR Range

E.4.2.3 Fuel Injector in Conventional Combustion

The function of the fuel injector is to introduce the fuel in the correct location in the primary zone for optimal mixing and efficient combustion. Gaseous fuel is typically injected into the air through a number of discrete holes, sized to ensure that the fuel is injected into the correct locale in the primary zone (see Figure E.4). With minor adaptions to control orifices and delivery holes, conventional combustion fuel injectors can operate on a wide range of different gaseous fuels with varying WI range (see E.6.3).

For liquid fuel operation, the fuel is injected into the air stream, where the fuel is rapidly atomized and allowed to evaporate. Fuel vapor then mixes similar to gas fuel operation.

E.4.2.4 Conventional Combustion—WLE

E.4.2.4.1 General

WLE combustion uses a conventional combustor and water or steam injected into the flame zone to reduce the maximum flame temperature of the flame zone and limit the NO_X production. Combustor structures are cooled and protected using techniques such as film and effusion cooling or thermal barrier coatings.

Water quenches the combustion process and increases CO and UHC production at lower power (see Figure E.2). The tradeoff between NO_X and CO is typical. The emissions can be optimized by minimizing hot and cold streaks in the combustor by ensuring good mixing of air, fuel, and water or steam.

WLE increases the power of the gas turbine by two main effects. The water or steam increases the turbine mass flow; hence, more power is produced. Water or steam can lower the combustor outlet temperature allowing an increase in fuel flow to return to the “dry” cycle temperature, hence generate more power.

WLE systems normally exhibit shorter hot section life than non-WLE systems. The increased water content in the combustion products can increase the heat transfer to the gas path components.

Water (not steam) injection increases the heat rate of the engine since fuel is used to evaporate water.

E.4.2.4.2 Water Quality

Deionized water, similar to boiler feed water, is used as trace quantities of contaminants will adversely deposit on the hot section components. NO_X levels of 25 ppmv (15 % O_2) on gas and 42 ppmv (15 % O_2) on diesel imply water consumption at the same or greater rate than the fuel flow (e.g. 130–200 % of fuel mass flow rate) with conventional combustors. A water treatment plant is usually required [about 50 gpm (11 m^3/h) for a 60 MW engine] deionized (< 1 mS/cm) water.

Additional power gained through the use of WLE will be lost if the water or steam injection is stopped. When water or steam is lost, the power output may need to be reduced to operate within the cycle temperature limits. To maintain the same power output, cycle temperature will increase and decrease component life. NO_X emissions will increase with the loss of water or steam.

Gas turbine manufacturers will describe acceptable concentrations of dissolved materials, pH, temperature, and other water properties (see 6.2.9). In many cases, water conductivity or pH is monitored in real time.

E.4.2.4.3 Water and Fuel Injector in WLE Combustion

Water is sprayed in during gas fuel operation through a dedicated circuit. With liquid fuel operation, water can be sprayed in separately or mixed with the liquid fuel and sprayed in as an emulsion. Not all multifuel gas turbines can inject water while operating on liquid fuel (see Figure E.6).

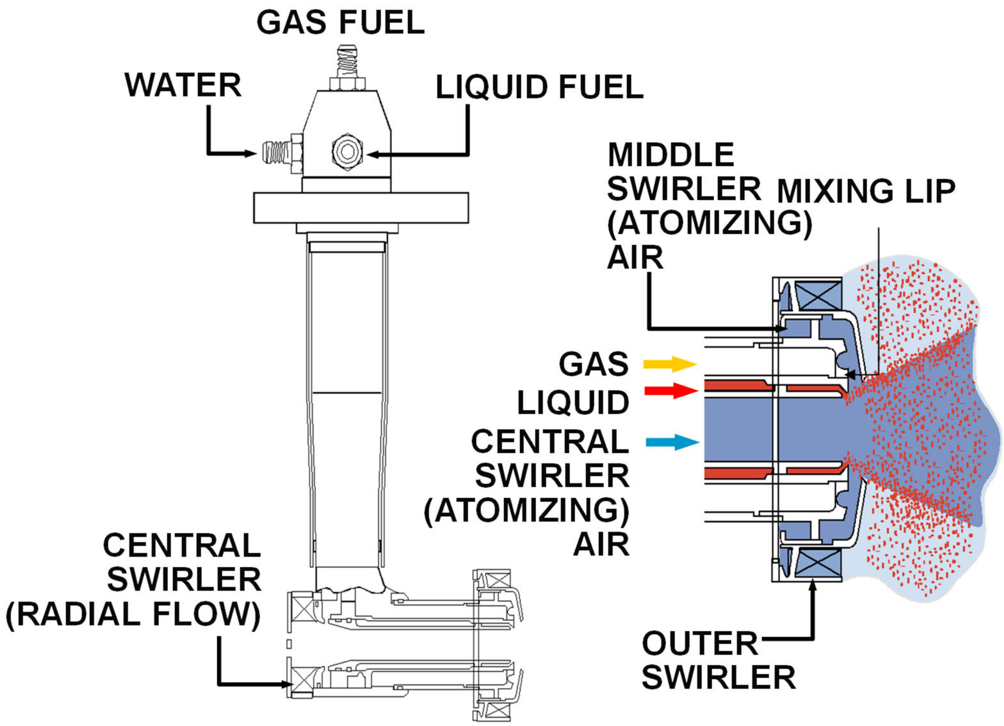


Figure E.6—Typical Fuel Injector

E.4.2.5 Conventional Combustor Considerations

E.4.2.5.1 Liquid Fuel Combustion

Gas turbine manufacturers can quote different overhaul lives depending on the running hours on liquid fuel versus gas fuel because the turbine blade metal temperature distribution is different.

Liquid fuels, typically #2 diesel (per ASTM D975), Class A1, A2 (per BS 2869), kerosene, and other acceptable distillates have to be atomized before being injected into the combustor. This is achieved by shearing thin sheets of fuel into small droplets which then evaporate as they are injected into the combustor (see Figure E.6).

E.4.2.5.2 Water-to-Fuel Ratio/Steam-to-Fuel Ratio

Water or steam is injected into the combustor for power augmentation and NO_X reduction (see E.4.3).

The water or steam may be injected in the combustor primary or secondary zone. For primary zone injection, lower injection rates are used and result in better NO_X reduction. In general, secondary zone injection would be at a higher injection rate, resulting in more power (compared to primary zone injection) and only slightly reduces the NO_X emissions.

Excessive water or steam injection can reduce the compressor surge margin or increase the level of combustion dynamics (combustor rumble). The increased water content in the combustion products can increase the heat transfer to the gas path components.

E.4.2.5.3 Purging/Packing of Dormant Circuits

WLE gas turbines are frequently dual-fuel (operate on gas or liquid fuel). The injector and fuel skids handle both fuels and transition between them. The gas and liquid circuits in the injector will be separate to accommodate the different volume flows thus one circuit may be inactive when operating on the other fuel. The inactive circuit is purged or packed with air or inert gas to ensure combustion products or hot air do not reverse flow into the passage and ignite or cause coking or fouling.

E.4.2.5.4 Physical Size

WLE combustors are generally more compact than DLE combustors. In aeroderivative engines, often the same combustor as aerospace is used. Thus, there is minimal effect to engine diameter or weight.

E.4.3 DLE (Premixed Combustion)

E.4.3.1 General

Conventional combustors produce high NO_X emissions due to the high flame temperature where the FAR is near stoichiometric. To reduce the NO_X emissions, a premixed combustor mixes fuel and air before entering the combustion chamber, with a lean FAR (air is the DLE diluent, similar to water or steam being the WLE diluent). The combustion temperature is low enough to reduce the breakdown of N_2 molecules into nitrogen atoms, thereby minimizing the formation of NO_X during the combustion process. Thus, the maximum primary zone flame temperature is limited to below ~1875 K (2900 °F) (see Figure E.2 and Figure E.10).

NO_X and CO production are influenced jointly by flame temperature and combustor pressure. At reduced gas turbine load both NO_X and CO concentration will increase. Most DLE systems are optimized at higher gas turbine loads.

Conventional combustion NO_X concentrations have been about 240 ppmv (500 mg/Nm^3) @15 % O_2.

DLE combustion NO_X concentrations have been reduced to less than 9 ppmv (20 mg/Nm^3) @15 % O_2.

Depending on the operation and gas turbine model, NO_X concentrations to less than 5 ppmv (10 mg/Nm^3) may be achievable without post combustion emissions treatment.

The NO_X and CO curves, in Figure E.2, show that both NO_X and CO emissions may be optimized by maintaining flame temperature, hence FAR, in a narrow range. Gas turbines have different designs to achieve this objective and nonoptimal emissions indicates issues such as poor mixing, premature quenching and lean or rich streaks in the combustor. Design options often include multiple fuel injectors that can be parallel or serially staged (see Figure E.8 and Figure E.9) to optimize emissions across the power range. Air staging, where compressor discharge air is diverted from the combustor (see E.4.3.3.6), can also be used to control flame temperature and emissions. Fuel staging (see E.4.3.3.5) is typically used on aeroderivative gas turbines.

Most DLE combustion systems are interchangeable with conventional combustion without affecting engine overall length or turbine hot section life. DLE hot section life is typically better than WLE. Changes have typically been confined to the combustor, fuel systems, and engine controls in packages.

E.4.3.2 DLE Combustor

DLE combustor (see Figure E.7) will have a fuel injector, premixer, and combustion chamber.

Prior to combustion, the fuel and air are mixed together to achieve the desired FAR. The mixture is then transported to the combustion chamber.

For liquid DLE combustors, the fuel is vaporized prior to premixing.

For flame stability, it may sometimes be necessary to use multiple fuel streams (i.e. pilot and main or staged combustion; see E.4.3.3.5). Multiple fuel streams better cope with transient load conditions. FAR is controlled from idle to baseload to avoid becoming too lean (flameout) or too rich (excessive NO_X). Maintaining target FAR in the combustor is also important during fast transients such as load acceptance and rejection.

For serial staged DLE (see Figure E.8), one set of premixers will flow fuel to power the engine. As power increases, the premixer will flow more fuel until it reaches the FAR and NO_X limit. At this point, fuel starts flowing in another premixer. Thus, increasing fuel flow to the engine is managed while also limiting the FAR (see Figure E.10) and NO_X.

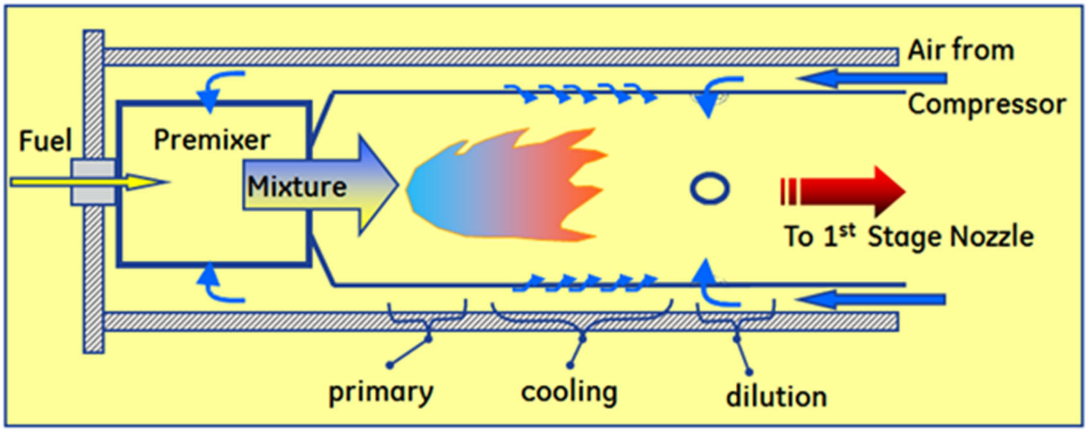


Figure E.7—DLE Combustor

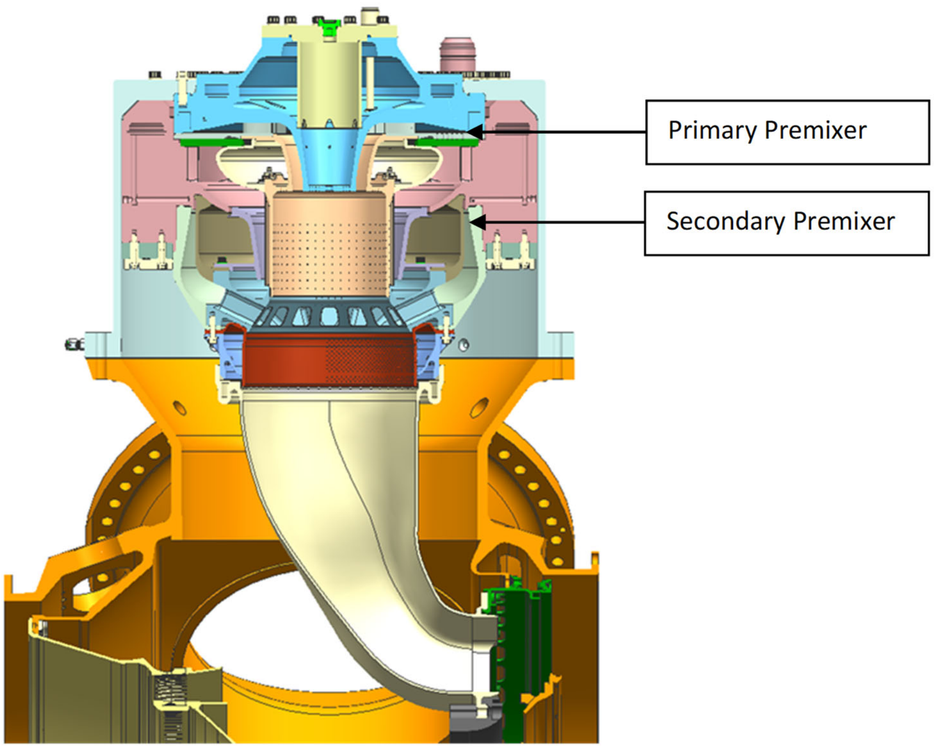


Figure E.8—Serial Staged DLE Combustor

NOTE The primary premixer flows fuel at low power and the secondary premixer adds additional fuel at mid and high power.

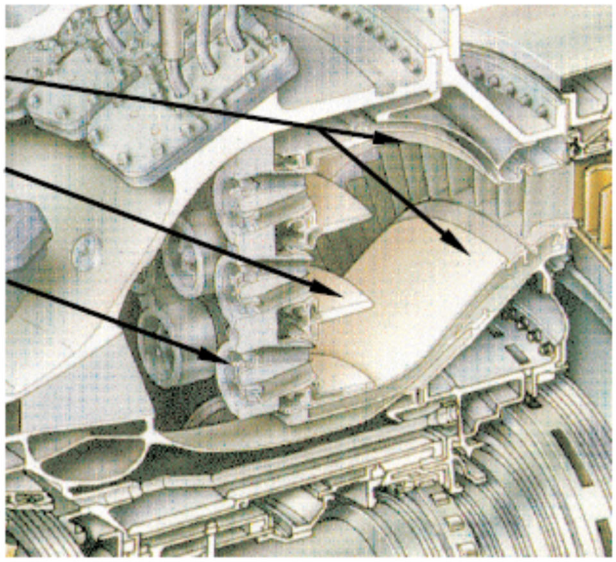


Figure E.9—Parallel Staged DLE Combustor

NOTE One ring of premixers is used at low power. Additional rings of premixers are brought on line at mid and higher power.

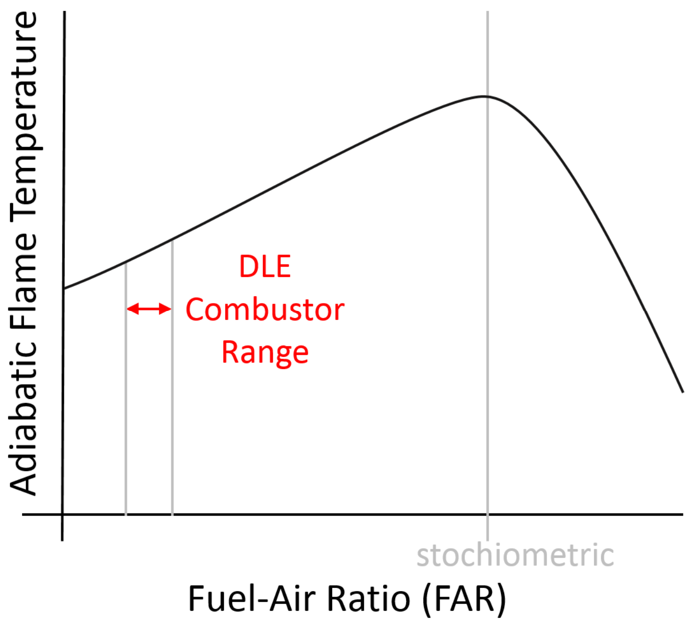


Figure E.10—DLE Combustion FAR Range

NOTE Premix combustors keep the FAR to a narrow range and to lower value of the flame temperature, hence minimizes the production of NO_X emissions.

E.4.3.3 DLE Combustion Considerations

E.4.3.3.1 General

DLE is popular because it produces lower NO_X emissions without water or steam injection. Since DLE is more complex, compared to conventional and WLE, some issues may remain; thus, the vendor and the purchaser should discuss project specifics during the proposal phase.

E.4.3.3.2 Flashback and Autoignition

If the flame speed exceeds the air and fuel mixture transport speed, flashback may occur and the flame may burn upstream back to the premixer. Fuel composition significantly affects flame speed. Hydrogen burns very rapidly so DLE combustors often have a requirement for fuel with a limited hydrogen content.

Autoignition delay time is the time an air-fuel mixture, at autoignition conditions (temperature and pressure), takes to autoignite. The autoignition delay time is strongly affected by the fuel composition, mixture pressure, and temperature. Autoignition delay time decreases as hydrocarbon molecular weight increases. Hydrocarbons heavier than propane (e.g. butane, pentane) have progressively shorter autoignition delay times. Gas turbine fuel specifications will limit the heavy hydrocarbon content of fuels. Fuel contamination from booster oil and other sources can unacceptably decrease autoignition delay time.

Transport speed and time are affected by the combustor design so care is taken to ensure ducts are smooth, with no slow or dead pockets. Poorly designed combustors can allow flashback (when the flame burns back faster than the local transport speed) or autoignition (where the fuel is in contact with hot air beyond the autoignition delay time) at the wrong location.

E.4.3.3.3 Starting and Stability

Some DLE combustors can only operate with premixed flame at medium or high power; hence, these combustors are started by a pilot flame or diffusion combustion circuit. The diffusion combustion circuit may operate from the startup to medium power. It is desired to shut off the diffusion combustion circuit as soon as practical, since this produces higher NO_X emissions.

Since premix combustors generally run lean, the combustor can be prone to flameout, especially during fast transient operations.

The diffusion circuit introduces complexity to the fuel system, particularly if the start system is used only for ignition of the DLE system.

A stable, pilot flame may be used but causes increased NO_X production.

E.4.3.3.4 Combustion Noise

DLE combustors can be acoustically excited resulting in very high amplitude pressure waves. This excitation can result in fatigue and failure of combustor parts. One source of the excitation is operating close to the lean blow out limit for minimum NO_X emissions. The result is that the flame has the least stability. The addition of tuned anti-resonators, fuel map modifications, intentional mistuning of the combustor, or active noise avoidance strategies are used to address this issue.

E.4.3.3.5 Fuel Staging

Combustor discharge temperature rises progressively with increasing engine power. However, there are limits on the FAR at the fuel injector. FAR is controlled from idle to baseload to avoid becoming too lean (flameout) or too rich (excessive NO_X). To accommodate the range of engine power, the fuel injectors are often staged where some injectors are not used at low power but flow fuel at high power.

The combustor may be parallel staged, where systems are inactive at low power and activated at high power. Conversely, the combustor may be serial staged where a primary system operates at low power and downstream systems are activated at medium and high power.

E.4.3.3.6 Air Staging

At low power and low combustor exit temperature, the DLE system may need to operate so lean that the combustor flames out. Air can also be bypassed around the combustor premixer in order to maintain DLE operation. Bleeding air from the compressor discharge makes the gas turbine less efficient and raises cycle temperatures at a given power.

The bleed-off air may be dumped overboard or re-injected to the gas turbine.

E.4.3.3.7 CO Turndown

As gas turbine power is reduced from baseload, CO production in the combustor may increase as the combustor exit temperature is reduced (see Figure E.2). Cycle temperature may be increased by bleeding air from the compressor (less air to cool the combustor). For an additional increase in cycle temperature, warm bleed air may be re-injected to the gas turbine. The increase in combustor temperature reduces CO with minimal impact on NO_X.

CO increase with reducing power applies to both WLE and DLE engines. Heat rate will increase as bleeding engine air reduces the engine thermal efficiency.

E.4.3.3.8 Physical Size

DLE combustors are typically larger due to the requirement to incorporate premixers and multiple fuel circuits. The combustor may also require additional volume and residence time to completely burn out CO. Aeroderivative gas turbine manufacturers usually strive to maintain a certain level of commonality between the industrial and flight versions of the gas turbine, including the combustor flange to flange distance. Thus, DLE combustors on these gas turbines often cause an increase to the gas turbine diameter as the DLE combustor structure is incorporated away from the engine centerline.

E.4.3.3.9 Fuel Composition

Compared with conventional and WLE combustors, DLE combustors are often more sensitive to fuel characteristics. For example, heavier hydrocarbons reduce autoignition delay time and increase the flame speed. Molecular hydrogen can increase the flame speed and risk of flashback. High concentrations of inert gases may require increased fuel pressure or larger fuel systems to provide the same chemical energy to the combustor (similar to a conventional combustor). High inert gas concentrations also decrease lean blow out margins and increase combustion dynamics.

E.4.4 Rich Quench Lean Combustion

In a rich quench lean combustor, the fuel that is burned is in a very rich zone, which consumes all the oxygen. The flame is then quenched rapidly by injecting dilution air. NO_X is minimized in the very rich zone, as there is no excess oxygen, and the quenching reduces temperatures below the zone where NO_X is formed.

NO_X is reduced from the levels achieved in conventional combustors but not to the state-of-the-art level achieved in premixed combustors; thus, rich quench lean combustors are not commonly used.

E.4.5 Catalytic Combustion

Catalytic combustion allows the fuel and air to burn at very low temperatures and minimize NO_X production. Fuel and air are mixed and passed over a catalyst that activates the reaction.

These combustors have a number of issues including large size, autoignition in the premixer section and a requirement to preheat prior to full catalytic operation. Catalytic combustion is not common.

E.4.6 Gas Fuel Variation

Fuels are grouped by WI range and the optimal injector is selected accordingly (see E.4.2.3).

For rich, high WI, fuels combustion dynamics (combustor rumble) may be an issue at low power. In this condition, the fuel flow and injector pressure is low so combustor pressure fluctuations may stall or reverse the fuel flow at the injector.

In the case of lean, low WI, fuels (e.g. high concentrations of inert components), higher fuel flow is needed. An injector with larger effective area may be required to prevent excessive increase in fuel injector pressure. The fuel conditioning system may also need to be larger or higher pressure.

E.4.7 Combustion Liner and Ducting

The flame is contained in the liner and ducted to the turbine section. For can combustors, transition ducts guide the combustor discharge from the individual combustor cans to a full annular duct. The liner and ducting also minimize circumferential and radial temperature and pressure distributions to the turbine.

The liner and ducting are made of high temperature alloys and are often thermal barrier coated. Effusion cooling is also used to form surface films to prevent direct hot gas impingement to the structure. Effusion cooling air minimizes air consumption. Excessive cooling air use leads to a higher FAR flame in the combustor and increased NO_X production.

E.4.8 Combustor Manifolds

The combustion system uses manifolds to supply fuel(s) and air (and sometimes water).

a) Fuel: gas and/or liquid fuel depending on the engine and combustor type.

b) Air: some injectors also have air for flushing and packing dormant circuits.

c) Water/Steam: a diluent to reduce NO_X production and/or augment power for conventional combustors.

Manifolds provide equal distribution of the fluids (fuel/water/steam/air) to the injectors. It is important for hot section life that each injector is equally fed. Nonuniform distribution creates combustor hot and cold spots. Staged DLE combustors have dedicated valving, manifolds and flex hoses for each stage.

Typically, the manifold is fabricated in two halves with flexible fuel hoses connecting the manifold to the injector.

Fuel pressure requirements vary widely by gas turbine model. Gaseous fuel systems can operate up to 4000 kPa (600 psi) gauge and liquid fuel systems can operate up to 21 MPa (3000 psi) gauge.

E.4.9 Ignition System

The ignition system is essential for gas turbine starting. The gas turbine is spun up on a starter motor to provide a continuous flow of air through the combustor. The ignition system introduces a continuous flame or high energy spark into the combustor to ignite the fuel. Once the fuel is ignited, the flame spreads and the fuel flow is increased until the self-sustaining gas turbine speed is achieved. During that acceleration process, the ignition system and starter motor are turned off once the gas turbine acceleration can be sustained by the combustion of fuel alone.

Annular combustors may be lit by one igniter, but two are generally fitted for redundancy (see 6.3.1).

Can combustors may be lit by one or two igniters per can. For DLE combustors, the igniter may fire directly in the premixer or light a pilot flame. The pilot is used to ignite and stabilize the primary premixer.

Can and cannular combustors also may be ignited by cross fire tubes where one can is lit by the igniter, but hot gas flows to neighboring combustors and provides ignition. Complete ignition is achieved by the hot gas progressively lighting all the cans through the network of cross fire tubes.

E.5 Emissions Measurement

E.5.1 General

Exhaust emissions measurement can be required by regulations. The measurement range is affected by the gas turbine design, fuel, load, air temperature, etc. and can be as low as a few tens of mg/Nm^3 (tens of ppmv dry) for CO and NO_X.

Portable or fixed measurement systems are used currently to measure exhaust emissions.

Portable measurement systems can be easily connected to the exhaust and are not dedicated to a single gas turbine unit. However, they need to be re-calibrated when installed and regularly during operation (e.g. 2–4 hours).

Fixed measurement systems [known as continuous emission monitoring systems (CEMS) or predictive emissions monitoring systems (PEMS)] also need recalibration. In this case, however, calibration hardware is embedded in the system and periodic re-calibration is automatically executed by the control software.

Both portable and fixed systems require regular maintenance.

E.5.2 Continuous Emission Monitoring Systems (CEMS)

CEMS are used to continuously monitor the concentration of chemical compounds in the exhaust. The most commonly measured compounds include NO_X (mainly NO and NO_2), CO, CO_2, SO_X (SO_2 and SO_3), UHC, VOC, and particulate matter. Oxygen (O_2) is usually measured since emission limits usually refer to a specific concentration of residual oxygen in the exhaust gas, typically 15 % volume. CEMS can also infer the exhaust flow rate.

In addition to the analyzer(s), the CEMS consists of several components. Probes usually sample exhaust gas in several locations along the exhaust duct diameter to give an averaged measurement. A pipe (usually heated to avoid condensation of water) brings exhaust gas from the duct to the analyzer. A conditioner (chiller) brings the exhaust samples to the analysis temperature and removes water by condensation.

Exhaust gas is directed through the system into the analyzer, which integrates several measuring devices, each of them suitable for one or more of the species to be determined. Chemiluminescence is commonly used for the determination of NO concentration, whereas nondispersive infrared and paramagnetic analyzers are commonly employed to measure CO and O_2, respectively.

CEMS require maintenance to preserve their accuracy and reliability. In particular, periodic calibration is performed with sample gases, available in cylinders with known and certified composition, to verify and adjust the “zero” and the “span” of each channel.

Most countries follow regulations such as United States Environmental Protection Agency Part 60 and Part 75 “Emissions Monitoring Policy Manual,” or the European Directive 2010/75/EU on industrial emissions. These rules provide threshold values under which the emissions are limited, but do not agree on a worldwide definition of such thresholds nor on how the emissions level are monitored and audited. Therefore, the practical application of these rules is mainly delegated to various legal entities acting on national or subnational basis, with a consequent spread of approaches and solutions. All regulatory directives agree on the use of CEMS to measure emissions levels, but the way data are stored and manipulated in order to create auditable databases is, in many aspects, left to the local entities.

E.5.3 Predictive Emission Monitoring (PEMS)

PEMS uses indirect measurements and estimations of gas turbine and plant operational data to calculate the concentrations of chemical compounds in the exhaust. The compound concentrations are mainly derived in two ways.

a) Non-physics-based model uses empirical correlation with gas turbine and plant operational parameters combined and measured emissions; these observed data are then extrapolated to create empirical models or correlations, in a pure data-driven way. Non-physics-based models need a period of observation, commonly known as the "training phase," and the model predictions are reliable only within the training phase range.

b) Physics-based models use knowledge of the specific combustion process taking place in the gas turbine. Physics-based models require less or no training, but is linked to the specific combustion process.

Both systems are corroborated with simultaneous measurements using calibrated equipment that can be used to validate the PEMS predictions.

Compared to CEMS, PEMS are smaller, easier to install and have lower maintenance requirements, since the PEMS is primarily software. PEMS compliance with area classification requirements (e.g. explosion proof regulations) should be easier than a CEMS. A PEMS should be easier to retrofit into space-constrained facilities. However, CEMS may be necessary due to factors such as regulations, contractual uncertainty, seasonal variation, and tolerances.

Indirect measurement systems, such as PEMS, are, in many cases, not accepted a priori and may require a case-by-case analysis to gain acceptance by the local entities.

E.5.4 Combustion and Emissions Treatment

E.5.4.1 General

The treatment of the exhaust to convert undesired chemical compounds to harmless compounds is a common practice in several industrial processes, and is widely used in the automotive industry to reduce the emissions of engines; the catalytic conversion of NO_X and CO and the filtration/oxidation of particulate matter is a standard subsystem of most cars. The same principle can be applied to gas turbines. An after-treatment is usually employed mainly to target very low NO_X emissions.

E.5.4.2 Selective Catalytic Reduction

Treatment processes for gas turbine exhaust NO_X abatement are usually based on selective catalytic reduction (SCR) of nitrogen oxide using ammonia (NH_3). Ammonia reacts with NO in the presence of oxygen, according to the following reaction:

$$4\ NH_3 + 4\ NO + O_2 \qquad 4\ N_2 + 6\ H_2O$$

The reaction occurs on specific vanadium-based catalysts, in monolith reactors installed on the exhaust of the gas turbine. The system is effective in a relatively narrow temperature range [~250–430 °C (480–800 °F)], so it may be necessary to adjust the exhaust temperature to match this range.

The catalytic reactor can also be fed with urea ($CO(NH_2)_2$), which is converted to ammonia, according to the following reaction:

$$CO(NH_2)_2 + H_2O \quad 2\,NH_3 + CO_2$$

When urea is employed as a reducing agent, ideally, the only emissions of a SCR system should be molecular nitrogen (N_2), water, and CO_2. In practice, if a high conversion of NO is desired, the fraction of ammonia that remains unreacted is not negligible. If not properly treated, unconverted ammonia could become a new undesired emission source. The unconverted ammonia can be oxidized in a subsequent catalytic stage [selective catalytic oxidation (SCO)] using precious metals (Pt, Pd) or transition metal oxides. Uniform mixing of urea/ammonia is required across the exhaust plane or NO_X and ammonia streaks will escape.

$$2\,NH_3 + 3/2\,O_2 \quad N_2 + 3\,H_2O$$

One of the key features of SCO catalysts is selectivity: NH_3 should be converted to N_2, but not further oxidized to NO. SCR/SCO units are able to reach NO_X conversion efficiencies in the range 70–90 %. However, due to the lifecycle impact (reducing reactants, catalyst maintenance, and possible exhaust gas pretreatment), such solutions are most practical on large gas turbines.

E.5.4.3 Selective Noncatalytic Reduction

An alternative process, similar to the SCR, is selective noncatalytic reduction (SNCR). As SCR, it requires a specific temperature range [typically 870 °C to 1200 °C (1600 °F to 2200 °F)] and the reaction occurring to reduce NO_X to nitrogen and water is:

$$2NO + 2\,NH_3 + \frac{1}{2}\,O_2 \quad 2\,N_2 + 3\,H_2O$$

or, if urea is used:

$$NH_2CONH_2 + 2\,NO + \frac{1}{2}\,O_2 \quad 2\,N_2 + CO_2 + 2\,H_2O$$

If ammonia is used as the reductant, it may be injected in gaseous form or as aqueous solution. Urea is typically used as aqueous urea (50 % by weight) and is pumped to the injection zones in the SNCR reactor; multiple injection zones are often needed.

This technology is quite stringent regarding the operative range; if the upper temperature is exceeded [above 1200 °C (2200 °F)], the following undesirable reaction occurs, leading to the formation of more NO_X:

$$NH_3 + O_2 \quad NO_X + H_2O$$

Similarly, below the optimum temperature, reduction reactions are too slow and unreacted reducing agent can be emitted; although the use of SNCR decreases NO_X, in these conditions, it may increase other undesirable emissions such as CO, N_2O, and NH_3.

Under ideal laboratory conditions, SNCR systems may reach great efficiency in NO_X removal; however, in practical applications the efficiency is usually much less because of the nonuniformity of the temperature profile in the combustor, difficulties with completely mixing the reducing agent into the exhaust stream and limited residence times.

It has been shown that the injection of inorganic salts could significantly broaden the temperature window for SNCR. Considering all these factors, the removal efficiency may vary from 20 % to over 60 %, but usually it does not exceed 75 %.

From an economic point of view, considering that catalyst is not needed, this method will be cheaper than SCR.

E.5.4.4 SCONO$_X$

A technology used to reduce NO$_X$ and CO from exhaust without the use of ammonia or urea, as required by other post-treatment methods such as SCR and SNCR, is the so-called SCONO$_X$; it is a catalytic absorption system, whose optimum temperature range is between 225 °C and 365 °C (440–690 °F), so it is suitable for combined-cycle and cogeneration plants but not for simple-cycle gas turbines.

The technology is capable of reducing emissions by approximately 90–95 % for NO$_X$ and 90 % for CO.

NO is oxidized in the presence of a platinum-based catalyst and the resulting NO_2 is then absorbed onto a potassium carbonate sorbent:

$2\ CO + O_2 \quad 2\ CO_2$

$2\ NO + O_2 \quad 2\ NO_2$

$2\ NO_2 + K_2CO_3 \quad CO_2 + KNO_2 + KNO_3$

Potassium nitrite and nitrates are present on the surface of the catalyst; the nitrates are regenerated to maximize NO$_X$ absorption. The sorbent is regenerated periodically with hydrogen coming, for example, from an on-site hydrogen reformer that consumes steam and natural gas (methane). Besides regeneration, periodic replacement of sorbent and catalyst are also needed. In particular from the analysis of diesel engine combustion products, it has been shown that the catalyst can deteriorate by sulfur masking; therefore, SCONO$_X$ may not be suitable for systems firing fuels other than natural gas or very high-quality low sulfur distillate fuel oil.

E.5.4.5 SCR Issues

The SCR is supplied with ammonia (or urea) during operation. Transportation and storage of ammonia entails specific handling requirements.

Ammonia is injected and mixed uniformly with the exhaust to react with all the NO$_X$ molecules. Unreacted ammonia can escape through the stack, termed “ammonia slip,” and is often a regulated emissions species.

The catalyst in the SCR is replaced or regenerated periodically. SCRs can be “poisoned” by sulfur in the exhaust gas. The sulfur can originate in the fuel or combustion air.

Since a SCR requires a certain exhaust temperature range, it may not be appropriate for application where the gas turbine does not operate long enough to reach the temperature range for a reasonable length of time (e.g. some peaking applications).

E.6 Fuels

E.6.1 General

Gas turbines have been successfully deployed with a wide range of fuels (e.g. low heating value fuels such as landfill gases to high heating value fuels such as associated gases from oil and gas recovery to liquid fuels such as naphtha, kerosene, and diesels).

Most industrial gas turbines operating today were developed for operation on pipeline natural gas or liquid fuels such as #2 diesel (per ASTM D975), kerosene or Class A1/A2 (per BS 2869) fuels and have since been adapted to operate on a wide range of associated gases and fuel oils.

Typical values for fuel properties are listed. Consult with the gas turbine vendor for details.

E.6.2 Gas Fuels

Each fuel gas needs to be evaluated by the gas turbine vendor, especially fuels of an unusual nature.

Pipeline gas (after gas plant treatment) is the most common gas turbine gaseous fuel. The typical constituents are as follows: CH_4, C_2H_6, C_3H_8, C_4H_{10}, C_5H_{12}, CO_2, N_2, H_2. Pipeline gas does not vary greatly in LHV, 45–55 MJ/kg (1100–1300 Btu/scf).

In many cases, a second or even a third fuel is used in the event that the primary fuel is not available; typically, these fuels are either associated gas or raw natural gas. An example is shown in Table E.1.

Table E.1—Fuel Composition, Pipeline, and Backup

	Customer Gas (Normal Pipeline and Backup)				
Mole %	Pipeline	Backup	Alt-1	Alt-2	Alt-3
Methane	92.7899	71.5175			
Ethane	4.16	1.0219			
Propane	0.84	23.8522			
i-Butane	0	1.0867			
n-Butane	0.18	1.1712			
i-Pentane	0	0.025			
n-Pentane	0.04	0.0099			
Hexanes	0.04	0.014			
Nitrogen	1.51	0.3347			
CO_2	0.44	0.9649			
H_2	0.0001	0			
Total mole %	100	100			
MW	17.292	24.167			
LHV (MJ/kg)	47.92	47.07			
LHV (BTU/scf)	939	922			
Wobbe index (MJ/Nm^3)	47.93	52.77			
Wobbe index (BTU/scf)	1215	1411			

NOTE This pipeline gas is midrange and suitable for most gas turbines, with either conventional or DLE combustors.

Fuels similar to those in Table E.2 can be burned in conventional combustion systems. DLE combustion systems are more restricted on what fuels they can utilize and are mainly limited to natural gas operation and a narrower range of associated gases. Special injectors have been developed for lower WI fuels (as low as WI = 10 MJ/Nm^3) with operational restrictions on a case-by-case basis. Gas turbine control software is also tailored to the fuel.

Table E.2—Other Fuels, Composition, WI, and LHV

Typical Alternate Fuels	Composition	**WI,** MJ/Nm^3 (BTU/scf)	**LHV,** kJ/sm^3 (BTU/scf)
Associated gases (gas recovered during crude oil extraction)	CH_4, C_2H_6, C_3H_8, C_{4+}, CO_2	33–60 (900–1600)	3350–6000 (950–1600)
Raw natural gas (reservoir dependent)	CH_4, C_2H_6, C_3H8, C_4H_{10}, C_5H_{12}, C_6H_{14}, CO_2, N_2, H_2	19–50 (500–1350)	1900–5000 (500–1350)
Refinery waste gas (gas for increasing H to C ratio in liquid fuels)	H_2, CH_4, C_2H_6, C_3H_8, C_4H_{10}, C_5H_{12}	39–47 (1050–1250)	1500–3500 (400–950)
Landfill gas (organic material decomposition)	CH_4, CO_2, N_2	8–30 (220–800)	820–3000 (220–800)
Coke oven gas	H_2, CH_4, CO, N_2, CO_2, O_2	24–32 (650–850)	2400–3200 (650–850)
Gasified biomass	H_2, CH_4, CO, N_2, H_2S	17–41 (450–1100)	1700–4100 (450–1100)
Digester gas (aneaerobic digester farm waste)	CH_4, CO_2, N_2	18–22 (500–600)	1900–2200 (500–600)

E.6.3 WI and MWI Variation

WI and MWI have been adopted by the industry to account for differences in fuel gas density, heating value, and fuel temperature.

$$MWI = LHV\sqrt{\frac{MW_{\text{air}}}{MW_{\text{fuel}} \times T_{\text{gas}}}}$$

$$WI = LHV\sqrt{\frac{MW_{\text{air}}}{MW_{\text{fuel}}}}$$

NOTE T_{gas} is absolute temperature (e.g. Kelvin or Rankine).

Low WI fuels can be accommodated in the gas turbine by increasing fuel system pressure, but there is a practical limit. In order to maintain practical fuel system pressure, the fuel system components such as pipes and injector hole sizes can be increased. Some gas turbines have a combustor option for low WI fuels comprising the larger pipes and injectors. In extreme cases, the combustor stator throat area is increased to pass the additional mass coming through the fuel system.

Low WI fuels may be difficult to ignite when starting the engine.

With very high WI fuel, very low fuel flow is required operate the engine at idle and low power. Low fuel flow rate implies low fuel system pressure. With low fuel system pressure, the normal combustor pressure fluctuations may stall or reverse the fuel flow at one or more fuel injectors. The intermittent fuel flow interruptions can lead to combustor “rumble” or increased combustion acoustics and dynamics response. Rumble and combustor noise will decrease with increasing fuel system pressure and engine power.

Vendors strive to offer fuel systems that accept a wider range of WIs and operate across the full power range without rumble or excessive fuel pressure. The range of fuels that are permitted to be used with any specific gas turbine will vary; gas turbine manufacturer should be consulted.

Where multiple fuels are used or where the fuel gas composition significantly varies, the capability of the gas turbine to adjust as the WI changes is important to avoid an unplanned shutdown. The predicted rate of change of the WI or MWI needs to be evaluated by the gas turbine vendor.

E.6.4 Liquid Fuels

Each fuel gas needs to be evaluated by the gas turbine vendor, especially fuels of an unusual nature. In addition to the fuel grade, contaminants (particularly those that are harmful to engine life) should be communicated to the gas turbine vendor.

When the fuel is a distillate (liquid), the practice is to describe the fuel as fuel oil #1 or fuel oil #2 (see ASTM D975) or Class A1/A2 (see BS 2869).

NOTE Heavy fuels such as fuel oils #4, #5, and #6 and their variations have been used, but typically require special treatment to meet gas turbine fuel specifications and will produce higher exhaust emissions.

Although details of several fuels are shown, 92 % of installed engines use pipeline grade gas, # 1, # 2 (see ASTM D975) or Class A1/A2 fuel oil. When associated gas and raw natural gas are included, this number increases to 98 %.

E.6.5 Fuel Supply Temperature

E.6.5.1 Gas Fuels

For gas fuels, there are two primary constraints on the minimum fuel temperature: maintaining the fuel above the dew point (hydrocarbon and water) and staying above the minimum design temperature of the fuel system. Liquids and solids in a gas system change the fuel spray pattern thus shifting the zone of heat release and can cause serious thermal damage to the gas turbine.

The minimum fuel temperature should be above 0 °C (32 °F), ideally 4 °C to 5 °C (40 °F to 41 °F). Fuel below 0 °C (32 °F) will potentially form ice on the exterior surfaces of pipes, flex hoses, and valves. Weight buildup and seizure of the valve are potential consequences. Also, methane and trace water at high pressure and close to 0 °C (32 °F) can form methane hydrate solids in the fuel system.

Gaseous fuel cools as it drops pressure while flowing through the fuel system. If the temperature drops too much, liquids will drop out of the fuel and enter the combustor. The fuel should be supplied at the inlet flange to the package at a superheated temperature [typically 25 °C to 35 °C (77 °F to 95 °F) (see ASME B133)] to ensure that no liquids drop out of the fuel. The gas turbine vendor can provide a skid edge temperature considering site-specific information.

E.6.5.2 Liquid Fuels

For liquid fuels, the temperature should be above the cloud point to prevent plugging of the filters and control components. It should also be above the temperature that corresponds to a viscosity of 12 cSt to ensure satisfactory atomization required for starting performance. The range of allowable temperatures is determined by the thermal capability of the materials in the fuel system.

For NGL fuels (e.g. naphtha, liquefied petroleum gas) the allowable temperature range is determined by the fuel system materials and the critical point of the lightest fuel. This latter constraint is to limit the vapor pressure on the fuel.

Liquid fuels are generally #1 or #2 (see ASTM D975) or Class A1/A2 (see BS 2869). Other liquid fuels can be used, such as #3 diesel, naphtha, condensates, etc. Fuel composition analysis is used by the gas turbine vendor to select the appropriate fuel conditioning system and combustion system. Major properties evaluated include:

a) viscosity;

b) density;

c) distillation curve;

d) aromatic content;

e) carbon;

f) carbon residue.

E.6.6 Air Contamination

See Annex F.

Inert particulates in the gas turbine inlet air cause erosion and fouling of the gas turbine. By limiting the size of the particulates, erosion is minimized. Contamination of the compressor blading is caused by smaller particulates. Factors such as humidity, presence of oil or soot, and dust particle composition affects the rate of fouling.

Some installations will have particulate material exhaust concentration emissions limits. In dusty locations, the inlet particulate matter concentration is determined in order to verify the net change in particulate matter level due to the gas turbine only.

E.6.7 Water Contamination

See E.4.2.4.2.

Inert solid particles in water can cause wear and plugging of control components and fuel injectors. Malfunctions of the control system and damage to the combustor and turbine section would be the result.

The pH of water is limited from slightly acidic (typically >6) to slightly basic (typically <8). Strong bases or acids can attack various components in the water control and injection system. Each gas turbine model has specific limits.

E.6.8 Fuel Contaminants and Limits

E.6.8.1 General

Conventional gas fuels using standard fuel systems and combustors need to be free of condensed hydrocarbons, oils, and water. All gas turbine manufacturers have fuel suitability requirements.

Fuel Contaminants:

Contaminant	Typical Limit	Test Method
Sodium and Potassium	0.5 ppmw	ASTM D3605
Sulfur	10,000 ppmw	ASTM D129
Vanadium	0.5 ppmw	ASTM D3605
Lead	1.0 ppmw	ASTM D3605
Calcium and Magnesium	2.0 ppmw	ASTM D3605
Fluorine	1.0 ppmw	ASTM D1179

NOTE The limits shown are typically total from all sources (fuel, combustion air, or water/steam).

Mercury, cadmium, bismuth, arsenic, indium, antimony, phosphorous, boron, and gallium are typically limited to 0.5 ppmw.

E.6.8.2 Liquid Fuel Contaminants

Appreciable amounts of water and sediment in fuel tend to cause fouling of the fuel handling facilities and cause issues in the fuel system. An accumulation of sediment in storage tanks and on filter screens may obstruct the flow of fuel from the tank to the package. Water in distillate fuels may cause corrosion of tanks and equipment. Water in the fuel also provides the conditions for microbiological growths to occur. These growths can plug filters and screens and can promote corrosion of fuel tanks.

Each gas turbine vendor may specify their own limits; typical values are listed below.

Solids: less than 2.6 mg/l of sediment (90 % less than 5 microns, maximum particle size 10 microns);

less than 2.6 ppmw (90 % less than 0.00013", maximum particle size 0.00025").

Water: <0.025 % by volume free water.

E.6.8.3 Handling and Storage of Liquid Fuel

As a guide for handling and storage, refer to ASTM D4418. Fuel samples should be taken and analyzed on a regular basis for physical and chemical properties.

The fuel handling equipment, pumps, including piping, should be cleaned with the final off-skid component consisting of nominal 10-micron filters. A constant flow transfer valve is used to allow filter replacement when the gas turbine is operating.

Liquid fuel storage tanks are susceptible to condensation and contamination from the environment.

Liquid fuel is usually contaminated prior to delivery to site and usually needs to be filtered before use.

E.6.8.4 Contaminants

E.6.8.4.1 General

The contaminants discussed below can be introduced in the fuel, combustion air, steam or water.

E.6.8.4.2 Sulfur

E.6.8.4.2.1 General

Typical values are listed in E.6.8, but gas turbine models may have specific limits.

Sulfur and sulfur compounds have an impact on the fuel system life and maintenance, turbine hot section life, exhaust system life, and exhaust emissions. The presence of sulfur in the combustor will burn or oxidize to form sulfur oxides (SO_X). In the presence of even minute quantities of sodium and potassium in the combustor environment (excess oxygen and high temperature), sodium and potassium sulfates are formed. These salts if condensed onto turbine airfoil surfaces will react with the base metal, resulting in hot corrosion (see Annex F) degradation. Gas turbines with waste heat recovery equipment should operate above the sulfuric acid dew point, which may require additional sulfur control to prevent cold end corrosion. Additionally, US Federal and certain local air pollution regulation require more restrictive limits on sulfur. Fuel bound sulfur in liquid fuel has been found to promote carbon deposits on hot surfaces of lean premix fuel injectors, leading to the blockage of liquid fuel passages over time. As a result, the sulfur content is limited for liquid fuel operation and is a function of the frequency and duration of liquid operation.

Fuel gases that contain sulfur compounds, can be corrosive to some materials, especially with the presence of liquid water and at higher pressures. If the sulfur exceeds the limit of standard materials, the fuel system materials can be upgraded. Combustor and hot gas path materials can also be upgraded, but at some sulfur level component life will be reduced.

E.6.8.4.2.2 Hydrogen Sulfide

Hydrogen sulfide (H_2S) can be found in natural gas, process, and manufactured gases. Hydrogen sulfide burns to sulfur dioxide and sulfur trioxide, which results in the corrosion described in E.6.8.4.2. Since hydrogen sulfide is toxic, if it is present in the gas, precautions should be taken to detect leaks.

E.6.8.4.2.3 Elemental Sulfur Deposition

Aside from H_2S, natural gas may contain other sulfur compounds or sulfur vapor that even in very low concentrations (ppbw) can form solid elemental sulfur. In sufficient quantities, elemental sulfur can impede operation of fuel valves and gas flow measurement devices on the gas turbine package. However, there are no reliable and practical methods for knowing how much elemental sulfur is contained in a gas and if and where elemental sulfur deposition will occur. If deposition takes place, the solution is to heat the gas fuel prior to the gas turbine skid edge. The temperature that the gas is be heated to will depend on the concentration of the sulfur in the gas supply. For standard pipeline gas with low concentrations of total sulfur, fuel heating in the range of 50 °C to 70 °C (120 °F to 160 °F) has proven effective at preventing sulfur deposition.

E.6.8.4.3 Sodium and Potassium

Typical values are listed in E.6.8, but gas turbine models may have specific limits.

Sodium and potassium can combine with vanadium to form a eutectic mixture, which melts at temperatures as low as 566 °C (1050 °F). These vanadium compounds can combine with sulfur in the fuel to yield sulfates with melting points in the operating range of the gas turbine. These compounds produce severe corrosion in the gas turbine hot section. Accordingly, the sodium plus potassium level is limited, but each element should be measured separately. These elements can be removed by water washing and subsequent removal with a centrifuge or electrostatic precipitator.

E.6.8.4.4 Vanadium

Typical values are listed in E.6.8, but gas turbine models may have specific limits.

Vanadium can form low melting compounds such as vanadium pentoxide which melts at 691 °C (1275 °F) and alkali metal vanadates, which melt as low as 566 °C (1050 °F), which can cause severe corrosive attack on all of the high temperature alloys in the gas turbine hot section.

E.6.8.4.5 Hydrogen and Carbon Monoxide

The presence of hydrogen and/or CO in the fuel gas above the specified levels can cause safety and materials problems. If hydrogen level is above 4 % by volume, a review of the fuel system materials for hydrogen embrittlement is required. If hydrogen level is between 4 % and 9 % or CO level is between 12.5 % and 18 %, then a specially sequenced start and purge system should be used. At hydrogen levels above 9 % or CO levels above 18 %, starts and accelerations can be made on a standard fuel with transfer to the hydrogen or CO bearing fuel at idle or above. If hydrogen level is above 4 % or CO is above 12.5 %, special safety provisions can be taken such as detectors in the package, separation of the engine and generator compartments and leak-free piping joints. Since CO is toxic, if it is present in the fuel gas, precautions should be taken to detect leaks.

E.6.8.4.6 Particulates in Gas

Solid particles in gas cause wear and malfunction of control components and fuel injectors. Malfunctions of the control system and damage to the combustor and turbine section will occur.

E.6.8.4.7 Mercury

Mercury compounds are corrosive to aluminum, copper, lead, and silver. Therefore, these materials are to be avoided if mercury is present. Mercury compounds are not known to be corrosive to the hot section of a gas turbine. Mercury in the exhaust of the gas turbine is limited to comply with local regulations.

E.6.8.4.8 Lead

Typical values are listed in E.6.8, but gas turbine models may have specific limits.

Lead can cause corrosion and in addition, it can spoil the beneficial effect of magnesium additives on vanadium corrosion. Since lead is rarely found in significant quantities in crude oils, its appearance in fuel oils is primarily the result of contamination during processing or transportation.

E.6.8.4.9 Fluorine and Chlorine

Typical values are listed in E.6.8, but gas turbine models may have specific limits.

Halogens such as fluorine and chorine as well as alkali/mixed halides and alkali sulfates can attack the protective oxide scale on hot turbine components thus accelerating the rate of oxidation.

E.6.8.4.10 Calcium and Magnesium

Typical values are listed in E.6.8, but gas turbine models may have specific limits.

Calcium and magnesium are not harmful from a corrosion standpoint; in fact, they inhibit the corrosive action of vanadium. However, calcium can produce hard bonded deposits that are not self-spalling when the gas turbine is not operating. These hard bonded deposits are not readily removed by water washing of the gas turbine. The fuel washing systems used to reduce the sodium and potassium levels will also reduce calcium levels.

E.6.8.4.11 Silicon (Siloxanes)

Siloxanes in fuel gas is known to result in silicon-based deposits in the gas turbine flow path that can cause damage, high rates of performance degradation, and increased maintenance. The rate of deposition is a function of the type and quantity of silicon-based material contained in the fuel and is produced from the combustion process. As such damage and performance loss is preventable only by control of siloxane levels in the fuel. Siloxane removal systems are available to control siloxane content.

E.6.8.4.12 Other Trace Metals

Oxides of other trace metals with or without impurities can be deposited on blades and vanes forming extremely hard and difficult to remove deposits. The presence of these oxides will also increase the rate of oxidation of blade and vane alloys at high temperatures.

Annex F
(informative)

Gas Turbine Inlet Air Filtration

F.1 Introduction

The following guideline is intended to serve as a reference for gas turbine inlet air filtration systems (example shown in Figure F.1). The inlet air filtration system cleans the air entering the gas turbine. This guideline applies to any gas turbine inlet air filtration system in any application. It is intended to provide a technically sound and practical guideline on selecting, operating, maintaining, and testing of filtration systems. This guideline discusses the purpose and advantages of inlet air filtration, consequences of poor inlet air filtration, selection of filtration system based on application, filters types and characteristics, filter operation and maintenance, and filter testing.

A primary reference for this annex and a recommended resource for gas turbine inlet air filtration is the "Guideline for Gas Turbine Inlet Air Filtration Systems," April 2010, Gas Machinery Research Council. Standards referenced in this guideline are ASHRAE 52.2:2012, EN 779, and EN 1822.

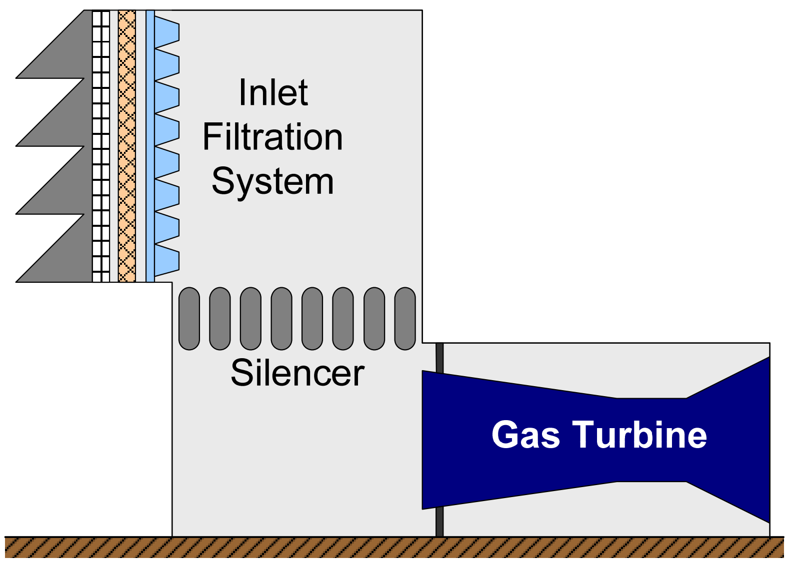


Figure F.1—Location of Gas Turbine Inlet Air Filtration System

F.2 Background

F.2.1 General

The operation of a gas turbine, by its basic design, requires it to ingest large quantities of air. For example, a 22 MW (30k hp) gas turbine with an exhaust flow of 68 kg/s (540k lbm/h) at 21 °C (70 °F) and 101.3 kPa (14.69 psi) absolute, and assuming inlet mass flow is 2 % less than exhaust flow, the volumetric flow is 200,000 m^3/h (120k acfm). Even in relatively clean environments, a gas turbine may ingest hundreds of pounds of foreign matter each year of various sizes (see Figure F.2). For example, 1 ppmv of particles in the ambient air is equivalent to 5.75 kg (12.5 lbm) of that particulate entering a gas turbine without filtration each day at a mass flow rate of 67 kg/s (530k lbm/h).

The foremost purpose of inlet air filtration is to clean the air to meet the operational goals of the machine (e.g. avoid damage and maintain gas turbine efficiency). Filtration is applied to the inlet air to provide protection against the effects of contaminated air. Different types of contaminants in the air from the worldwide variety of environments can cause several types of problems that negatively impact the reliability, availability, and time between overhauls of gas turbine internal components. Specific filtration designs are also selected to protect against particles of various sizes and composition and to maintain filtration efficiency over a long time period.

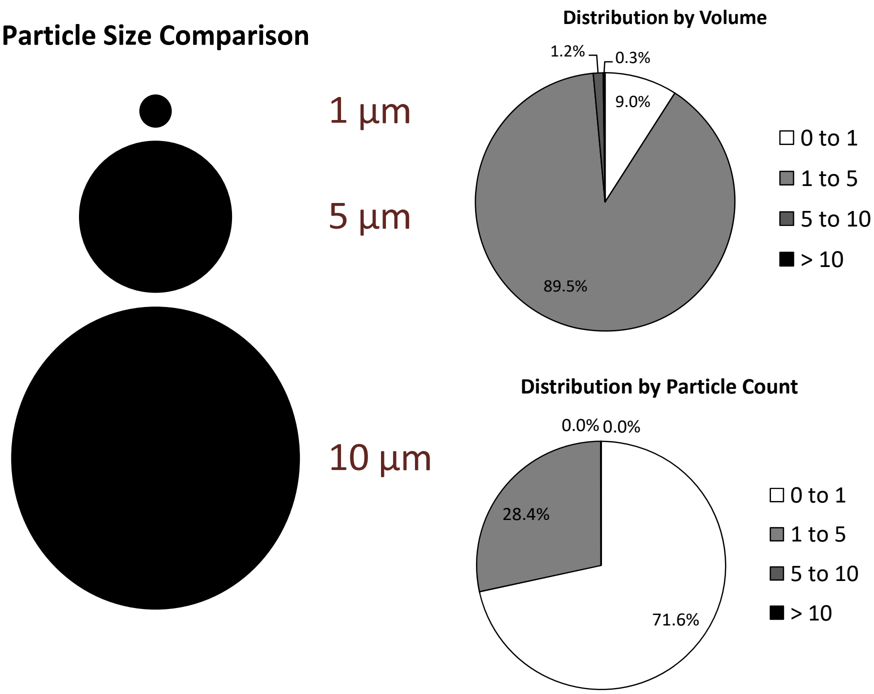


Figure F.2—Distribution of Particles in Atmosphere

F.2.2 Consequences of Poor Inlet Air Filtration

F.2.2.1 General

In order to understand the importance of inlet air filtration, the effects of poor filtration on the gas turbine should be understood. The gas turbine is affected by various substances in the inlet air depending upon their composition and their particle size. Discussed below are six common consequences of poor inlet air filtration: foreign object damage (FOD), erosion, fouling, turbine blade cooling passage plugging, particle fusion, and corrosion (hot and cold).

F.2.2.2 FOD

FOD occurs when objects or particles, which are not part of the gas turbine, are ingested into the compressor section of the gas turbine and damage the gas turbine (usually the compressor section) causing performance deterioration, extensive airfoil damage, or gas turbine failure. FOD can be significant in a gas turbine if there is not proper protection (see Figure F.3). FOD usually occurs in the first few stages of the compressor section. Objects or relatively large particles can be filtered (trapped or screened) to stop their entry into the gas turbine compressor section. The filter system and its components are designed to prevent FOD. Poorly designed filters or systems, including filters, hardware in ducting and silencing, and other aspects lead to a risk of FOD. “FOD screens” can be installed downstream of the filters and upstream of the gas turbine bell mouth. Depending on the screen location and mesh size, the pressure loss across the FOD screen can be negligible or significant.

Ice formation downstream of the air filters can also cause FOD. Anti-icing systems and air filtration systems are intended to mitigate ice formation.

Figure F.3—Gas Turbine Damage from FOD

F.2.2.3 Erosion

Solid and liquid particles 5 to 10 microns or larger create erosion of the metal surfaces within the air flow path. Figure F.4 compares the particle size range for erosion with fouling. Sand is one of the most common causes of erosion due to its prevalence at the gas turbine installations. Water droplets are also a common erosive particle. Water droplets can come directly from the atmosphere (e.g. rain or a nearby water surface) or be condensed during fogging, cleaning, and wet combustion systems. Impingement of these small particles removes metal particles, eventually reshaping the airfoils. Reshaped airfoils will reduce the gas turbine efficiency. More significantly, reshaping aerodynamic surfaces changes the air flow paths, roughens the surfaces, changes clearances, and eventually reduces the cross-sectional areas that provide the strength necessary to resist the very high stresses. Also, changing the blade shape can create stress concentrations that reduce the fatigue strength, potentially leading to high-cycle fatigue failures.

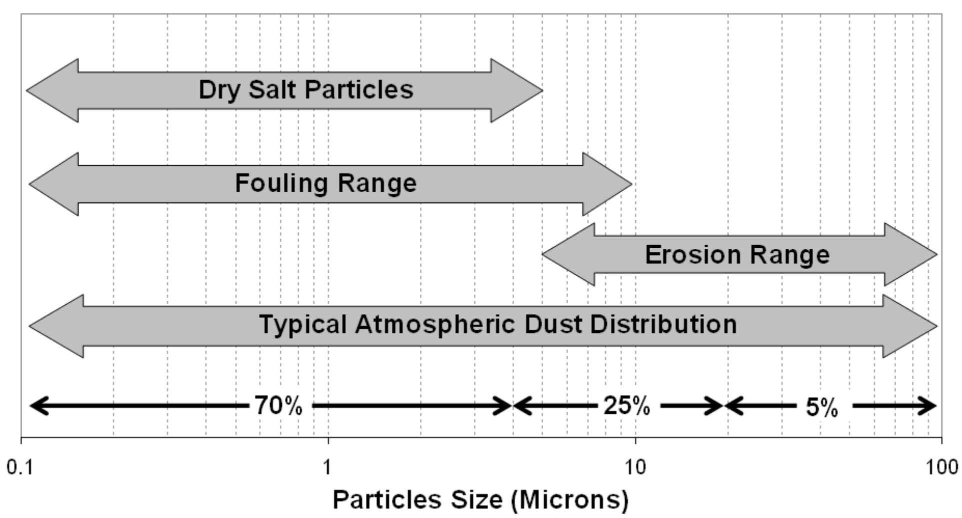


Figure F.4—Typical Particle Size Distribution for Erosion and Fouling Range

Erosion is a nonreversible problem. The only method of restoring blades to their original condition is with replacement. Particles of sizes greater than 5 microns are usually the culprit for erosion and can be easily filtered with commercially available filters. In environments with a high concentration of large dust (> 5 microns), such as deserts with low humidity levels, self-cleaning type filters can be effective for removing these particles. Inertial separators can also be used to remove these particles in applications with high filter velocity. An example of erosion on the leading edge of a turbine blade is shown in Figure F.5.

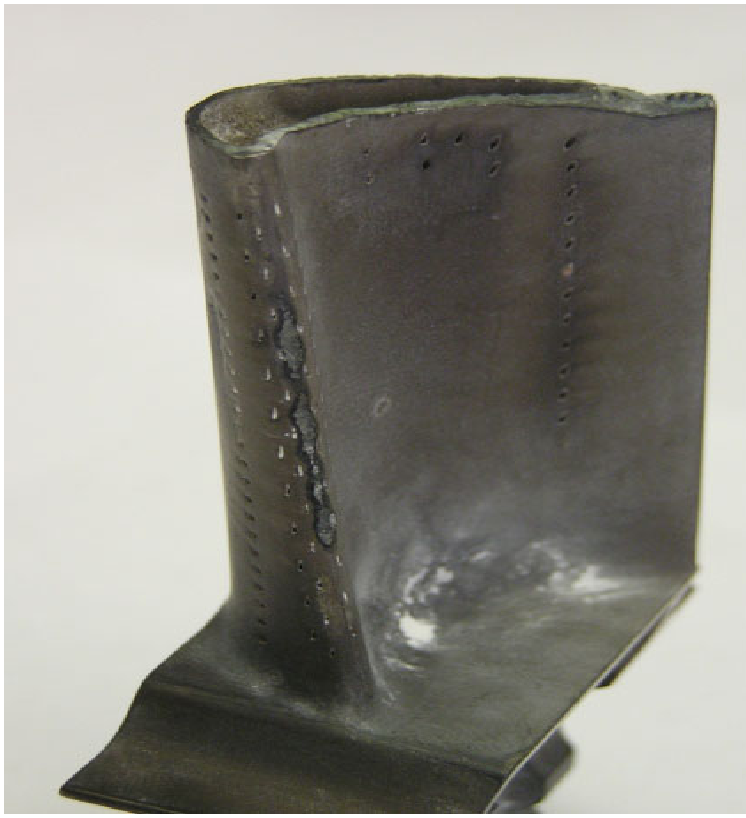


Figure F.5—Erosion on the Leading Edge of a Turbine Blade

F.2.2.4 Fouling

As particle size and particle hardness are reduced, the potential problems change from erosion to fouling. Fouling is the buildup of material in cavities and low flow rate locations along the air flow path. Small particles, oil vapor, water, salts, and other sticky substances working individually or together create a mix of materials that find places to adhere. These places are compressor blade surfaces and turbine blade cooling passages. The effect is to change clearances, disrupt rotating balance, obstruct and plug flow paths and reduce smoothness of rotating and stationary blade surfaces which decreases gas turbine efficiency and performance. Fouling is, however, usually recoverable since there are methods available to remove these deposits with online or offline washing or mechanical cleaning. Removing the fouling can interrupt process output and sometimes requires an extended shutdown. It is possible to recover performance to close to the new and clean performance with regular cleanings. An example of change in gas turbine performance over time is shown in Figure F.6. Note that after each cleaning, the performance of the gas turbine is slightly reduced (i.e. nonrecoverable loss). Fouling causes increased gas turbine fuel consumption for the same power output. Historically, online washing is done daily or weekly depending on the environment and level of filtration that is used. A typical cleaning frequency for offline washing is every 3 months.

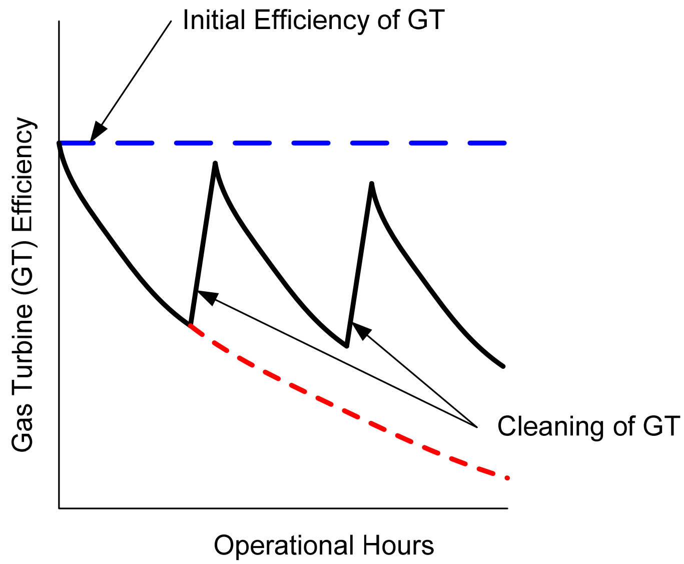
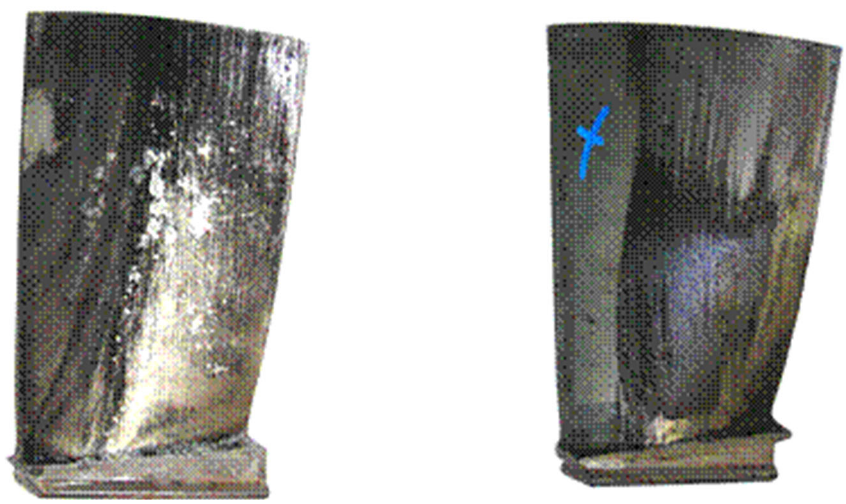


Figure F.6—Effect of Cleaning on the Efficiency of a Gas Turbine

Hard particles in the submicron range can be easily removed with the proper filter. But submicron components such as oil vapors and water are difficult to remove, and special filters are required. Also, the location, height, and orientation of the filtration system inlet can be designed to minimize intake of some of these substances. For example, if an exhaust stack is located near the gas turbine, the filtration system inlet can be oriented to minimize the exhaust ingested from this stack. Figure F.7 shows an example of fouling on compressor blades.



Carbon **Oils**

Figure F.7—Fouling on Compressor Blade

F.2.2.5 Corrosion

F.2.2.5.1 General

If the material ingested into the machine is chemically reactive with the gas turbine parts, the result is corrosion. There are two classifications of corrosion in gas turbines cold corrosion and hot corrosion.

F.2.2.5.2 Cold Corrosion

Cold corrosion occurs in the compressor due to wet deposits of salts, acids, steam, aggressive gases (e.g. chlorine, sulfides). This removes material over an area or concentrated corrosion resulting in pitting (see Figure F.8) that can result in reducing cross-sectional properties. The results of corrosion can be very similar to erosion, except that corrosion can intrude into cracks and metallurgical anomalies. Corrosion can initiate cracks or defects that can lead to blade liberation with extensive secondary damage. These corrosion effects are irreversible. The only way to restore the blades to the original condition is with replacement. Note that inlet air filtration can remove solid and liquid particles but cannot remove corrosive gases.

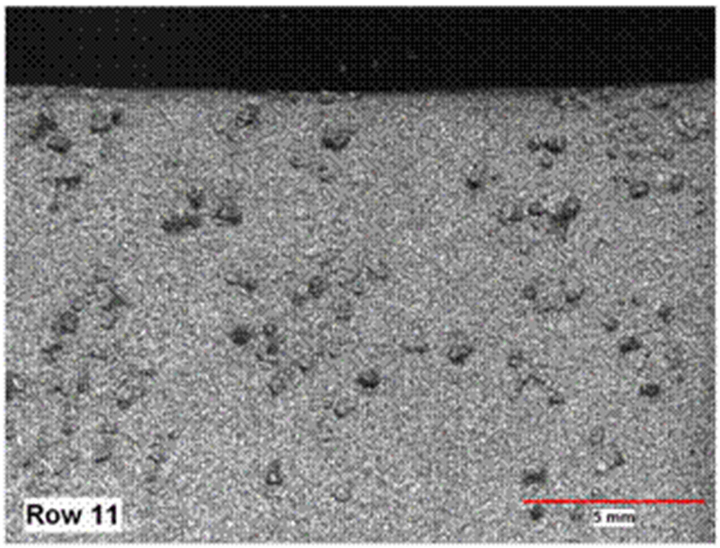


Figure F.8—Corrosion/Pitting on a Compressor Blade

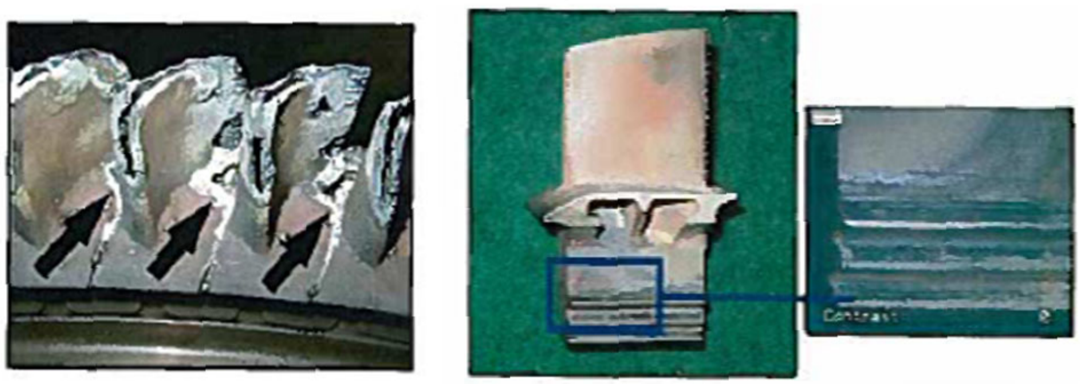
F.2.2.5.3 Hot Corrosion

Hot corrosion occurs in the combustor and turbine area of the gas turbine that are exposed to contaminants not just from the air, but also from the fuel (see E.6.8) or water/steam injection. Therefore, air filtration alone cannot prevent hot corrosion. Metals such as sodium, potassium, vanadium, and lead react with sulfur and/or oxygen during combustion. After combustion, these metals will deposit on combustor liners, nozzles, turbine blades, and transition pieces and cause the protective coating (oxide film) on these parts to rapidly oxidize (i.e. corrode). Hot corrosion is a form of accelerated oxidation that is produced by the chemical reaction between a component and molten salts deposited on its surface. Hot corrosion comprises a complex series of chemical reactions, making corrosion rates very difficult to predict. Degradation becomes more severe with increasing contaminant concentration levels.

The mechanism and rate of hot corrosion is highly influenced by temperature. When turbine blades are in operation, there is a temperature gradient across the blade. Due to this gradient, the temperature at the root is lower than the blade itself, so the root may experience a hot corrosion mechanism different than blade tip corrosion. The selection of appropriate alloys and coatings for the materials of the components in the hot section of the gas turbine can help to mitigate hot corrosion failures, but the preferred path of preventing this type of failure is through proper filtration. If possible, the levels of sodium and potassium from the inlet air should be kept below 0.01 ppmv with filtration to prevent hot corrosion. Control of the level of sulfur in the fuel would help to avoid hot corrosion, but this is typically impractical because removal of sulfur from fuel is a complex process. It is much easier to control sodium and potassium levels in the inlet air through mechanical filtration.

Hot corrosion occurs in two variants: Type I and Type II. Type I hot corrosion occurs in the temperature range of 850 °C to 950 °C (1550 °F to 1750 °F). At these temperatures, metal salts melt and adhere to the surfaces in the gas turbine. These salts attack the protective oxide film and eventually start to destroy the base material of the component. The main salt that is seen in Type I hot corrosion is sodium sulfate (Na_2SO_4). This salt can form if the incoming air contains sodium or if the fuel contains sulfur. Other impurities that can combine with sodium sulfate are vanadium, phosphorus, lead, and chlorides. These impurities will reduce the melting temperature of the sodium sulfate and allow the hot corrosion to occur at lower temperatures.

Type II hot corrosion occurs at temperatures in the range of 650 °C to 800 °C (1200 °F to 1500 °F) when in the presence of a high concentration of sulfur in the fuel supply. It also occurs with cobalt- and nickel-based materials in the presence of sodium and sulfur in the air or fuel gas.



Turbine Blade Failure Root of Turbine Blade Failure

Figure F.9—Examples of Hot Corrosion Failures

F.2.3 Use of Filtration

The effects of inlet air filtration are both positive and negative. Inlet air filtration will help sustain gas turbine performance and minimize the occurrence of the degradation effects discussed above. The negative side of filtration is pressure loss, resulting in reduced performance or efficiency of the machine. Gas turbine inlet air filtration becomes a trade-off. Cleaner air with reduced particle or moisture content controls wear and fouling at reduced gas turbine efficiency. Unfiltered or less-filtered air at lower pressure loss gives better gas turbine efficiency initially, but unfiltered air will result in temporarily or permanently damaged gas turbine components. Thus, it is clear that filtration is needed. The challenge is to minimize pressure loss while removing a satisfactory amount of particles and moisture.

Effective filtration can require several filter stages to remove different materials from the air, or to remove more particles, different phases (solid, liquid), or smaller particles. Filters to remove rain and snow, mist, smoke, or dust and finer particles all require variations in filter design. The most common approach to meet these varied needs is the use of multiple stage filtration systems, usually with two or three stages, each stage with a different purpose and design.

The selection of filtration systems is based on the expected operating environment. The changing seasons, prolonged rainy periods, snowstorms and sandstorms, changes in dust composition, insects, organic materials such as pollen, cotton residues, and leaves have to be considered. Specific local conditions influence filter design and location; wind direction, local air pollution, elevation of the inlet above ground level, and local air flows caused by buildings or terrain. There are also several other aspects of filter operation that should be considered in the design and selection process: gas turbine load, load variation, gas turbine availability requirements, filter face velocity, desired pressure loss for gas turbine performance, particulate size, filter efficiency, dust holding capacity, filter loading (surface and depth), and wet operation.

Various types of filters are discussed in F.3.3, which are used to meet the requirements of inlet air filtration. These include weather protection, trash screens, inertial separators, moisture coalescers, prefilters, high-efficiency filters, and self-cleaning filters.

Filters are classified by several standard rating methods. In the United States, the methods are defined by the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) in standard 52.2:2012. In Europe, these classifications are set by European Standards EN 779 and EN 1822. The classifications are given to the filters based on standard tests for capturing certain size particles with a defined efficiency.

F.3 Filter Selection

F.3.1 General

Gas turbine inlet air filtration is an important feature in the selection and purchase of the gas turbine. Properly selecting and maintaining the filtration system can increase the performance and life of the gas turbine and minimize the planned and unplanned maintenance. This section discusses the necessary information to determine which type of filtration system is needed for different applications. It includes a review of filter characteristics related to performance, operation, life, and maintenance. Considerations for environmental factors are discussed with a focus on marine, coastal, offshore, and land applications.

F.3.2 Filter Characteristics

F.3.2.1 General

To properly select a filtration system, the contaminants need to be understood. Also, it is important to understand the filtration parameters and how these are affected by the operating environment. Finally, the types of filters that are commercially available should be known.

F.3.2.2 Gas Turbine Contaminants

A contaminant is any undesirable substance which is entrained in the air. Contaminants can be solid particles, gases, and liquids. Some examples are sea salts, dust, sand, factory discharge gases, exhaust fumes containing oil and fuel vapors, particles such as chemicals, fertilizers, mineral ores, and any variety of industrial by-products. Contaminants existing in the environment where the gas turbine operates are highly dependent upon the location and the surrounding local activities (e.g. other industrial sites, farming, mining). Contaminant concentrations can vary daily or seasonally due to climatic conditions such as wind direction, wind speed, temperature, relative humidity, and precipitation. Also, the contaminants can change in the future with the changes in surrounding land use. For example, if a nearby area is designated for future agriculture use, then plant and soil dust could be present in the air during planting and harvesting seasons. Each gas turbine site should be thoroughly evaluated for the expected contaminants. The inlet air filtration system should be designed to filter contaminants expected in that environment. Table F.1 lists some common contaminants and their typical size and the rated filters (based on applicable standards) that can remove these contaminants. Note that only solid and liquid contaminants can be removed by mechanical filtration; however, gaseous contaminants should be reported to the filtration manufacturer for consideration in the system design. Filter ratings are discussed in F.3.2.3.3.

Table F.1—Common Contaminants and Appropriate Rated Filter

Grade	ASHRAE Filter Class MERV	EN Filter Class	Particles Separated
Coarse (> 10 microns)	1	G1	Leaves, insects, textile fibers, sand, flying ash, mist, rain
	2	G2	
	3	G2	
	4	G2	
	5	G3	Pollen, fog, spray
	6	G3	
	7	G4	
	8	G4	
	9	G4	
Fine (> 1 micron)	10	M5	Spore, cement dust, dust sedimentation
	11	M6	Clouds, fog
	12	M6	
	13	F7	Accumulated carbon black
	14	F8	Metal oxide smoke, oil smoke
	15	F9	
EPA and HEPA (> 0.1 micron)	16	E10	Metal oxide smoke, carbon black, smog, mist, fumes
	16	E11	
	16	E12	Oil smoke in the initial stages, aerosol microparticles, radioactive aerosol
		H13	
		H13	
		H14	Aerosol microparticles
		H14	
ULPA		U15	Aerosol microparticles
		U16	
		U17	
NOTE Correlations between ASHRAE and EN standards classifications and particle size are approximate.			

F.3.2.3 Filter Parameters

F.3.2.3.1 General

Filter parameters to obtain the most suitable filtration system for the application are discussed below.

F.3.2.3.2 Filtration Mechanisms

Filters are designed to use multiple mechanisms to remove the particles of various sizes. The mechanism employed by the filter depends on the velocity through the media, fiber size, packing density of the media, particle size, and electrostatic charge. In a single filter, the different mechanisms work together. Five basic filtration mechanisms include inertial impaction, diffusion, interception, sieving, and electrostatic charge.

It is important to note that electrostatic charge filtration is only present during the beginning of the filter life. The electrostatic charge is applied to the filter before installation during the manufacturing process. Filters always lose their electrostatic charge over time because the particles captured on their surface neutralize the electrostatic charge. As the charge is lost, the filter efficiency for small particles will decrease. However, it should be noted that as the filter is loaded, the filtration efficiency increases. This will offset some of the loss of filtration efficiency due to the lost charge. Figure F.10 shows a comparison of a filter's total efficiency based on the various filtration mechanisms. Figure F.10 shows the difference between the filter's efficiency curve before and after the charge is lost. A best practice is to report the performance of the filter based on the discharge condition as done when following EN 779 or ASHRAE 52.2 test procedures.

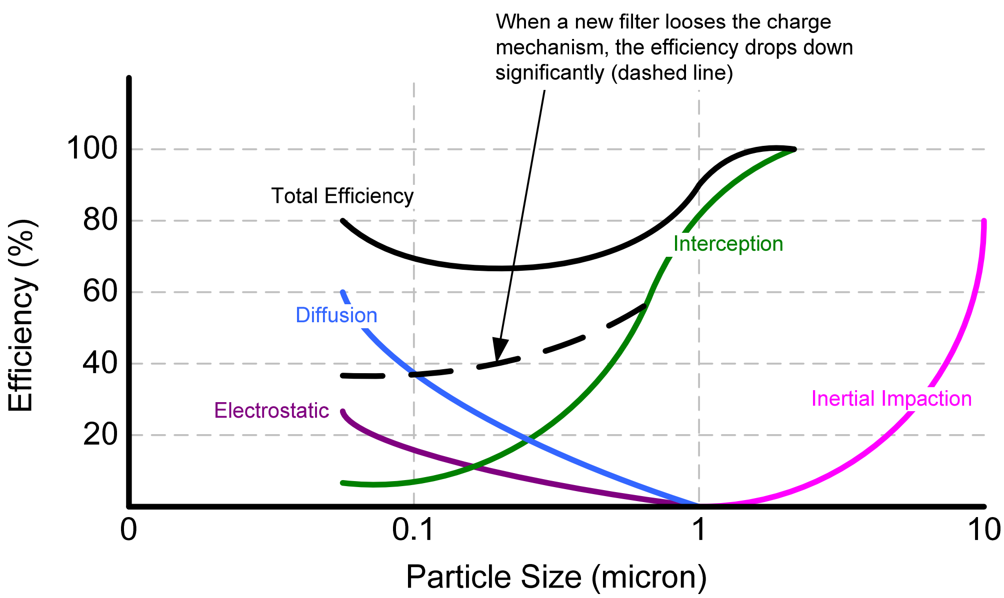


Figure F.10—Combination of Filtration Mechanisms to Obtain Filter Efficiency at Various Particle Sizes

F.3.2.3.3 Filter Efficiency and Classification

Filter efficiency is a broad term. In general, the filter efficiency is the ratio of the weight, volume, area, or number of particles captured to particles entering the filter. The weight efficiency is calculated as shown in Equation (F.1). The efficiency can be expressed in several ways: maximum, minimum, or average lifetime value. Many filters have poor performance against small particles at the beginning of their lives, but as the filter media becomes loaded with particles, it is able to catch smaller particles. In this case, the average efficiency would actually be higher than the initial efficiency. Some of the filters will never reach the quoted maximum efficiency before they are replaced.

$$\eta = \frac{W_{\text{entering}} - W_{\text{leaving}}}{W_{\text{entering}}} \times 100\ \% \qquad \text{(F.1)}$$

Filter efficiency is a trade-off against the pressure loss and holding capacity of the filter. Normally, the filtration system pressure loss will increase with an increase in filtration efficiency. As filters become more efficient, less dust penetrates through them. Also, the air flow path is more constricted with higher efficiency filters. This leads to higher pressure loss. Filter engineers determine the acceptable pressure loss and efficiency for their application. Studies have shown that a higher pressure loss due to using a high-efficiency filter has a lower overall effect on gas turbine power degradation than allowing poor inlet air quality.

The efficiency of a filter cannot be stated as a general characteristic. The filter efficiencies vary with particle size, typically being lower for small particles and higher for large particles. It also varies with operational velocity. Filters designed for medium and low velocities will have a poor performance at higher velocities.

Therefore, a particle size range and flow velocity are associated with the stated efficiency. For example, a filter may have 95 % filtration efficiency for particles greater than 5 microns at a volumetric flow rate of 85 m^3/min (3k cfm), but the efficiency could be reduced to less than 70 % for particles greater than 5 microns at a volumetric flow rate of 115 m^3/min (4k cfm).

When selecting a filter from different manufacturers based on efficiency, ensure that the comparison uses ratings with consistent test standards and test conditions. Pay attention to the air velocity used for the test, particle type, environmental conditions, and particles sizes. The air velocity should be comparable to the expected operating conditions. If the actual operational velocity is significantly higher than the test velocity (ex. 50 %), then it can be expected that the performance of the filter will be reduced.

These filter ratings are based on the results of standard performance tests. Filters are rated for performance based on standards established in the United States and Europe.

In the United States, ASHRAE standard 52.2:2012 outlines the requirements for performance tests and the methodology to calculate the efficiencies. In this standard, the efficiencies are determined for various ranges of particles sizes. The filter is given a minimum efficiency reporting value (MERV) rating based on its performance on the particle size ranges (particle count efficiency) and the weight arrestance (weight efficiency).

The European standards used to determine performance are EN 779 and EN 1822. EN 779 is used to rate coarse (G), medium (M), and fine (F) efficiency filters. EN 1822 presents a methodology for determining the performance of high-efficiency filters: efficient particulate air (EPA) filters, high-efficiency particulate air (HEPA) filter, and ultra-low particle air (ULPA) filter. In EN 779, the performance for medium and fine filters is found with average separation efficiency (based on particle count), which is an average of the removal efficiency of 0.4-micron size particles at four pressure drops (loadings). The fine filters also have a minimum particle count efficiency requirement. The course particle filters classification is determined with an average arrestance (weight efficiency). Note that all filters tested under the EN 779 standard are tested and classified in the discharge condition. This standard rates the filters with a letter and number designation: G1 to G4 (coarse filters), M5 to M6 (medium filters), and F7 to F9 (fine filters).

Filter performance is determined by the most penetrating particle size efficiency (MPPS) in EN 1822. The MPPS is defined as the particle size which has the minimum filtration efficiency or maximum penetration during the filter testing. Figure F.11 shows an example of test data from an EN 1822 test. Note that the efficiency actually improves for particle sizes below the MPPS of 0.16 microns. The typical range for MPPS is 0.12 to 0.25 microns per EN 1822. The filter efficiency is calculated based on particle count. These filters are given a rating of E10 to E12 for EPA type filters, H13 to H14 for HEPA type filters, and U15 to U17 for ULPA filters. Table F.2 gives a general overview of the efficiencies for each filter rating and a comparison of the filter ratings between American and European standards.

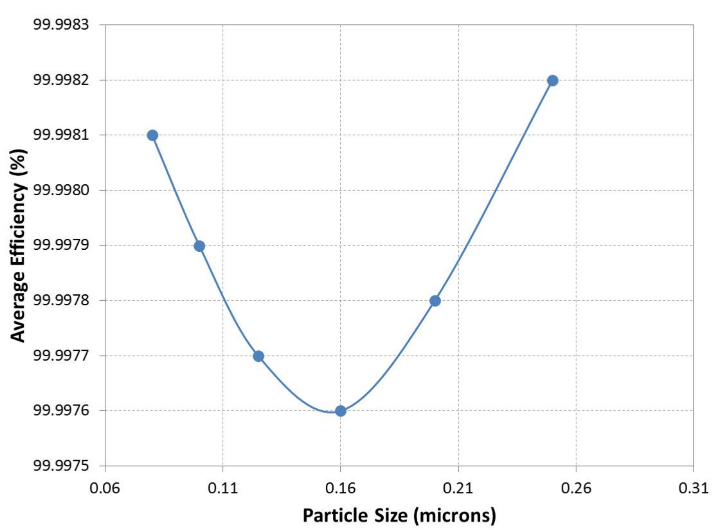


Figure F.11—Example of Data from an EN 1822 Test (MPPS is 0.16 microns)

Table F.2—Classification of Filters Based on American and European Standards

ASHRAE Filter Class	ASHRAE 52.2:2012				EN Filter Class	EN 779			EN 1822
	Average Arrestance (%)	Composite Particles Size Efficiencies in µm (%)				Average Arrestance (%)	Average Efficiency at 0.4 µm (%)	Minimum Efficiency at 0.4 µm (%)	Average Efficiency at MPPS (%)
		E_1	E_2	E_3					
MERV		0.3–1.0	1.0–3.0	3.0–10.0					
1	$A_{avg} < 65$			$E_3 < 20$	G1	$50 \le A_m < 65$			
2	$A_{avg} < 65$			$E_3 < 20$	G2	$65 \le A_m < 80$			
3	$A_{avg} < 70$			$E_3 < 20$					
4	$A_{avg} < 75$			$E_3 < 20$					
5				E_3 20	G3	$80 \le A_m < 90$			
6				E_3 35					
7				E_3 50	G4	$90 \le A_m$			
8				E_3 70					
9				E_3 85	M5		$40 \le E_m < 60$		
10			E_2 50	E_3 85					
11			E_2 65	E_3 85	M6		$60 \le E_m < 80$		
12			E_2 80	E_3 90					
13			E_2 90	E_3 90	F7		$80 \le E_m < 90$	35	
14		E_1 75	E_2 90	E_3 90	F8		$90 \le E_m < 95$	55	
15		E_1 85	E_2 90	E_3 90	F9		$95 \le E_m$	70	
16		E_1 95	E_2 95	E_3 95	E10				< 85
					E11				< 95
					E12				< 99.5
					H13				< 99.95
					H14				< 99.995
					U15				< 99.9995
					U16				< 99.99995
					U17				< 99.999995

NOTE Correlations between ASHRAE and EN standards classifications are approximate.

F.3.2.3.4 Filter Pressure Loss

As mentioned above, a higher pressure loss occurs with a more efficient filter due to air flow restrictions. Pressure loss has a direct impact on the gas turbine performance. This causes the inlet pressure at the compressor of the gas turbine to be lower. In order for the compressor to overcome the inlet system losses, the gas turbine has to consume more fuel, and it also has a reduced power output. The relationship between the inlet air filtration system and pressure loss is linear as shown in Figure F.12. This shows that as the pressure losses increase at the inlet, the power decreases, and the heat rate increases linearly. A 50 Pa (0.2 in. water) reduction of pressure loss can result in a 0.1 % improvement in power output. Typical pressure losses on inlet air filtration systems can range from 0.5 kPa to 1.5 kPa (2 in. to 6 in. water).

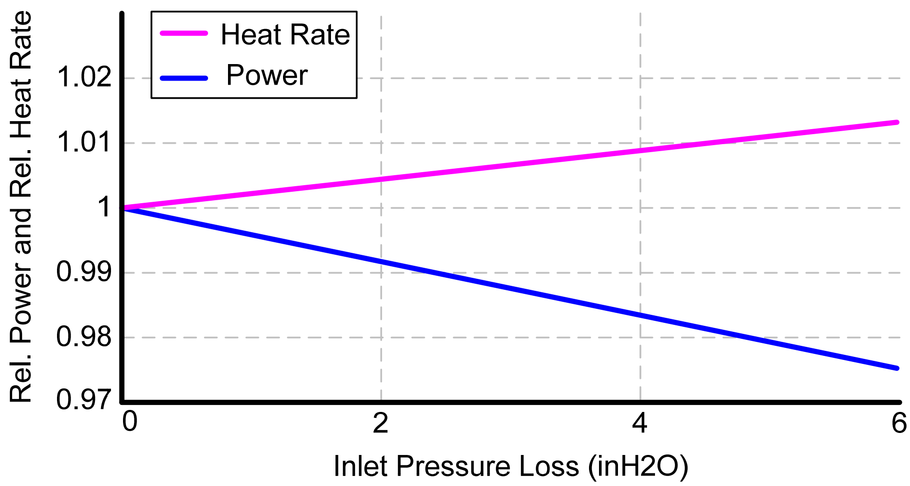


Figure F.12—Typical Effect of Pressure Loss at Inlet on Gas Turbine Power and Heat Rate

Filter performance needs to be assessed for the full pressure loss range over its life, not just when it is new. While filtering performance improves as the filter loads, however, the differential pressure across the filter increases, which will have a corresponding negative impact on power output, thermal efficiency and heat rate. If a filter is selected only based on the initial pressure loss, then expect lower gas turbine performance over the life of the filter or more frequent filter replacement to maintain the lower pressure loss required for gas turbine performance. The change of pressure loss over time is highly dependent upon the filter selection and the type and amount of contaminants experienced.

One method that many filtration system manufacturers have taken to reduce the pressure loss is to decrease the filter face velocity. Decreasing the face velocity reduces the viscous and flow restriction effects which lead to lower pressure losses. Decreases in face velocity are achieved with larger filter surface area. The larger surface area also creates more fiber media for particles to be trapped in, so the filter is able to retain more dust during its life. Increased surface area seems like an ideal solution, but more surface area means a larger filtration system. Also, more filters will need to be replaced during maintenance intervals. Offshore and marine applications often do not have space for more surface area, which leads to the use of high-velocity filters.

Reducing the pressure loss can also be accomplished through design of the inlet system ducting. Designs that have many flow path changes and turns can cause added pressure loss, high velocities across the filters, or poor aerodynamics in the ducting. The best practice is to make the duct as straight as possible and use gradual turns with turning vanes. In the design stage, computation fluid dynamics (CFD) can be used to estimate the pressure loss through the duct system and optimize the design. Figure F.13 shows an example of a CFD particle flow analysis in a filtration system.

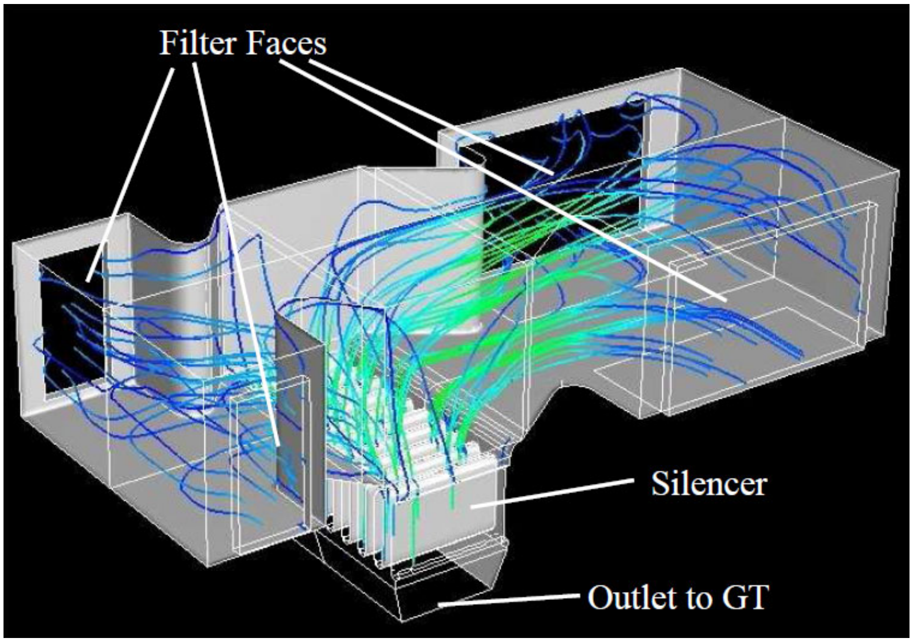


Figure F.13—Example of CFD Analysis in Inlet Air Filtration System

F.3.2.3.5 Filter Loading

During operation, as the filter collects particles, it is loaded until it collapses. However, when the high differential pressure alarm is reached, the filter is usually considered "full."

Filters are loaded in two different ways: surface and depth loading. Depth loading is the type of filtration where the particles are captured inside of the filter media. To regain the original pressure loss or condition, the filter has to be replaced. When using depth loaded filters, it is important to understand what dust holding capacity the filter has. A high specific dust holding capacity indicates that the filter can collect more dust, while the pressure loss increases at a slower rate. Figure F.14 shows a graphical differentiation between a low and high specific dust holding capacity filters. The low-capacity filter will have a higher pressure loss with the same amount of dust collected as the high-capacity filter. The dust holding capacity is not only dependent upon the filter construction but also the particle size distribution. A filter will load up more quickly with fine dust than with large dust. For a given pressure loss, a filter can hold a greater mass of large particles than of small particles.

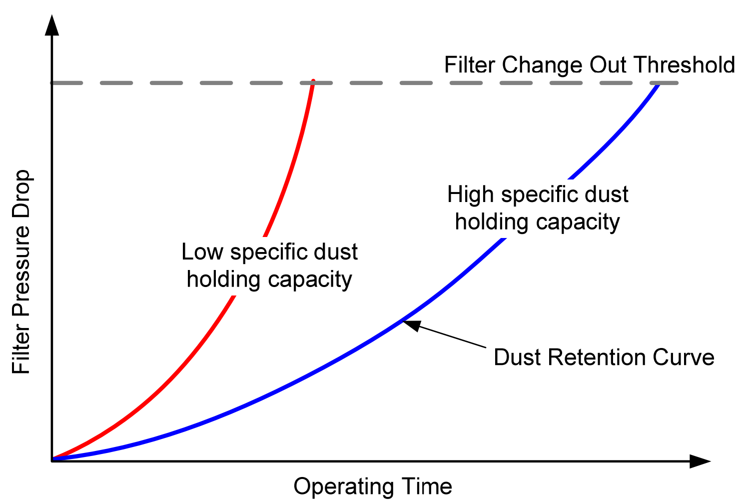


Figure F.14—Comparison of High and Low Specific Dust Holding Capacity Filters

The low-capacity filter may be used in an environment with a low amount of dust in the air where minimal filtration is required. In areas with medium to high dust concentrations or with fine dust particles, a high-capacity filter may be used to maximize the time between filter replacements and reduce maintenance. Also, if the filters are changed based on a fixed maintenance interval due to plant shutdowns, the lower average pressure loss over time will allow better overall gas turbine performance.

The other type of filter is a surface loaded filter. With this type of loading, the particles collect on the outside surface of the filter media. Some of the particles may infiltrate the fiber media, but not enough to call for replacement of the filter. Surface loaded filters are most commonly used in, but not restricted to, self-cleaning systems. This is due to the fact that the dust can easily be removed with pulses of air once the filter differential pressure reaches a certain level. Once the filter is cleaned, the pressure loss across the filter will be close to when it was new. The surface loaded filter's efficiency actually increases as the surface is loaded with dust. This is due to the fact that a dust cake, developed on the surface of the media, creates an additional filtration layer and also decreases the amount of available flow area in the filter media.

F.3.2.3.6 Face Velocity

F.3.2.3.6.1 General

Filtration systems can be classified as high-, medium-, or low-velocity systems. The velocity of the filtration system is defined as the actual volumetric air flow divided by the total filter face area. Low-velocity systems have air flow at less than 2.5 m/s (500 ft/min) at the filter face. Medium velocities are in the range of 3.1 m/s to 3.5 m/s (610 ft/min to 680 ft/min). High-velocity systems have air flows at the filter face in excess of 4 m/s (780 fpm).

F.3.2.3.6.2 Face Velocity Effects

The face velocity in the filtration system will influence the size, weight, and maintenance of the system. There is a range of face velocities available in filtration systems. The face velocity should be selected based on the requirements of the application. If size and weight are more important than pressure loss, then a higher-velocity system is used. Or if the pressure loss is more important than size and weight, a lower-velocity system is typically selected.

Lower-velocity systems are characterized by large inlet surface areas, large filter housings, and usually multiple stages of filters. These systems will have a lower pressure loss due to the large flow surface area. Since these systems are fairly large and heavy, they are not typically used in locations that have strict weight and size requirements. The surface area on lower-velocity systems is large; therefore, the time between filter replacements is longer as compared to medium and high-velocity systems.

Filtration systems that operate with a medium velocity can have filtration efficiency comparable to their low-velocity counterparts with multiple stages of filtration, but will have a higher pressure loss. The medium-velocity systems surface area will be reduced as compared to the lower-velocity systems; therefore, the filters will reach a full status and need replacement more often. These systems do provide the advantage of being more compact and lighter than the lower-velocity systems. Therefore, they can be useful in locations that have moderate weight and size restrictions but desire a lower pressure loss as compared to a high-velocity system.

Lastly, high-velocity systems are generally the most compact and light systems available. These systems can have a simplistic design with one or two stages, but they can have more complex arrangements with multiple stages of filtration. The pressure loss on the high-velocity systems is higher than the other systems due to the minimal surface area. Also, the filters on the higher-velocity systems will need to be changed at a higher frequency. One notable high-velocity system design is the vane/coalescer/vane system. This system is normally used in the marine environment and is focused primarily on keeping seawater from entering the gas turbine.

Some filtration systems use special configurations (see Figure F.15 and Figure F.16) of the filter banks to reduce the face velocity. Reducing the face velocity generally decreases the pressure loss and increases the filtration efficiency. Figure F.15 and Figure F.16 show various configurations used in static and self-cleaning filtration systems. The W shaped filter configuration maximizes the surface area available for the filters. In this type of system, it may be possible to reduce the overall housing footprint.

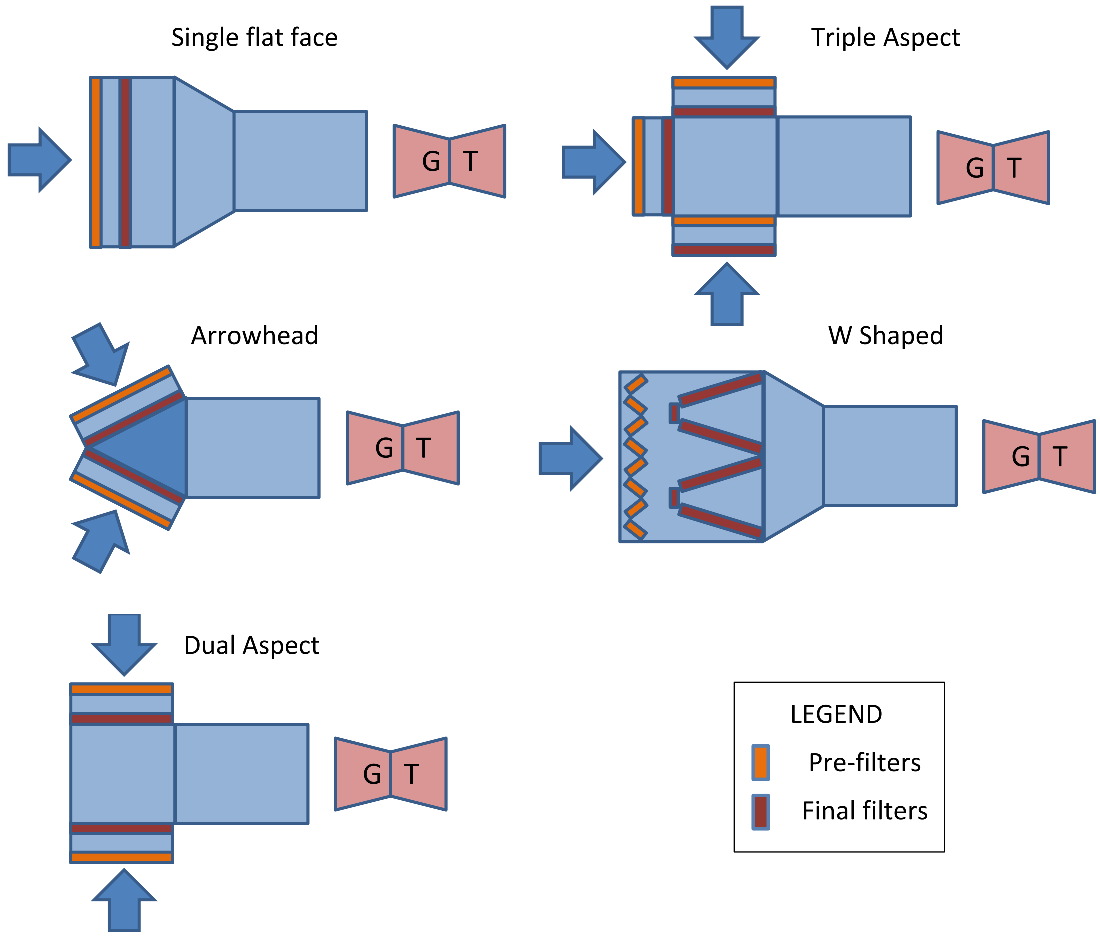


Figure F.15—Static Filtration System Configurations

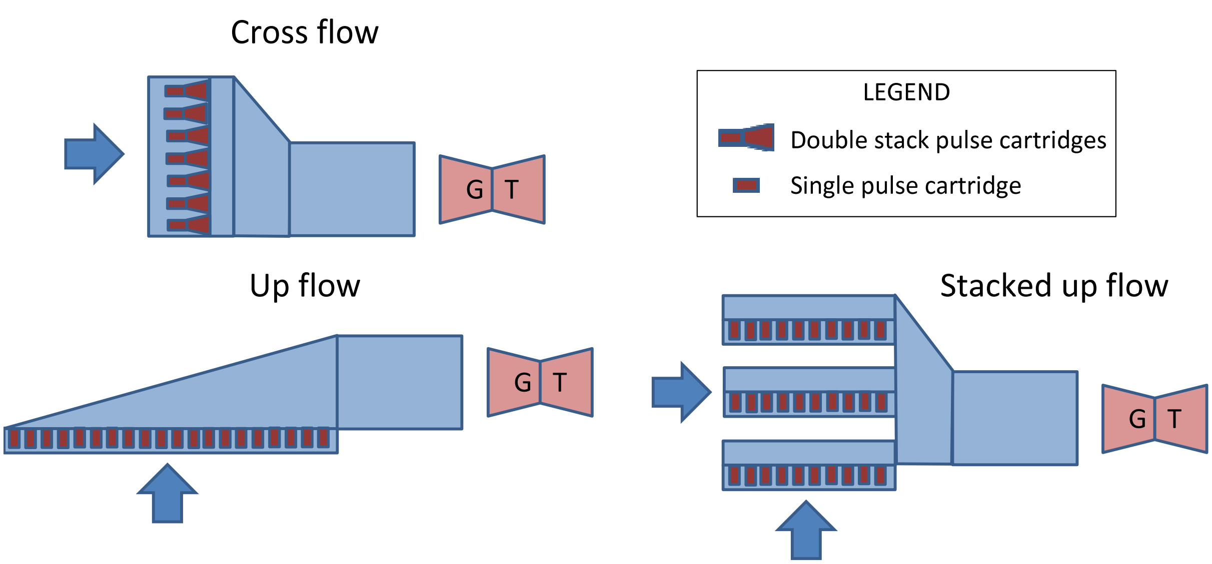


Figure F.16—Self-cleaning Filtration System Configurations

F.3.2.3.6.3 Importance of Face Velocity

Filter performance is given at a nominal velocity, which is chosen by the entity requesting the performance test. Gas turbine filter manufacturers test their filters at flow velocities representative of a typical in-service velocity. The testing of the filter is conducted at this nominal velocity, and the values reported in the manufacturer's literature will be at this velocity. If the operational velocity of the application is close to the nominal velocity, then the filter may perform as expected. If the operational velocity of the application is higher than this velocity, then the filter will have a higher pressure loss, deviation from reported efficiency, and reduced dust holding capacity.

F.3.2.3.7 Operation in Wet Environment

Many environments where gas turbines operate will have wet ambient conditions (e.g. jungle, coastal, significant rain, offshore). Table F.3 is a list of the different types of moisture that can be experienced with their particle size. Most filters are not designed to operate in a wet condition, but some filters are required to do this due to their ambient conditions. The difference between filter operation in wet and dry conditions can be significant. In some cases, the pressure loss across a filter can increase significantly even with a little moisture. This is true for cellulose fiber filters that swell when they are wet. These filters will also retain the moisture, which can lead to long periods of time when the pressure loss across the filter is elevated.

Table F.3—Different Types of Moisture Experience in Inlet Air Filtration Systems

Description	**Liquid Size** (microns)
Humidity	Vapor form
Smog (more smoke than humidity)	0.01 to 2
Cooling tower aerosols	1 to 50
Water mist	1 to 50
Clouds and fog	2 to 150
Water spray (ship wake, ocean spray)	10 to 500
Drizzle	50 to 400
Rain	400 to 1000

Early morning fog can also add moisture to filters. Experience has shown that the pressure loss across certain filtration systems increases during the occurrence of fog and for many hours after the fog has cleared. Coalescers and vane separators can be used to remove the droplets of moisture. Filter media can be selected for wet operation. Also, the operator should expect to have reduced filter performance (and therefore gas turbine performance) during periods of wet operation. It is important to note that high-efficiency filtration systems are more sensitive to moisture entrainment than lower-efficiency systems. Because of this, systems with F9 and higher filters require more upstream stages to operate well in wet environments.

When a significant amount of moisture enters the filtration system, the filters can become saturated. Since filters are designed to capture and hold onto particulates, the water that adheres to the filter will interact with these particulates. Some of the particulates such as dirt and salt can be absorbed by the water. If the water is able to travel through the filter, then this dirt and salt that was previously captured on the filter can be carried downstream to other filter stages or to the inlet of the gas turbine. Water vapor can lead to ice formation on the gas turbine bell mouth if temperature is not controlled (see anti-icing; F.3.3.7.2).

As discussed above, surface loading filters work by capturing the dust on the surface of the filter instead of inside the fibers. If this filter gets wet, then the dust on the outside of the filter will stick together and form a semi-permanent cake. In a self-cleaning system, the reverse pressure pulses may not be strong enough to remove this cake from the filter. Therefore, the self-cleaning ability will be reduced. Pre-filter socks are often placed around the self-cleaning filter to mitigate caking. When the socks are used, the effectiveness of the self-cleaning feature is reduced; therefore, the pulsing mechanism is often turned off. The socks can be removed and replaced while the gas turbine is still running. The mechanism of self-cleaning systems will be discussed in F.3.3.7.7.

F.3.2.3.8 Salt Effects

Salt can have a direct effect on the life of a gas turbine if not removed. As discussed in F.2.2.5, salt in the gas turbine can have serious consequences. This is especially true if there is high sulfur content in the fuel. Salt can also deposit on the compressor blades which leads to fouling and reduced aerodynamic performance. The salt on compressor blades has to be removed through water washing methods or direct scrubbing of the blades. Gas turbine manufacturers usually recommend stringent criteria on the amount of salt that can be allowed to enter the gas turbine (less than 0.01 ppmv). In coastal environments (e.g. 0 to 12 miles from coast), the air borne salt can easily range from 0.05 ppmv to 0.5 ppmv on a typical day, but high chloride air can extend much further inland, depending on prevailing wind direction. If the inlet air filtration system is not equipped to capture the salt, then it can pass directly through to the compressor and to the hot section of the gas turbine.

For onshore-based filtration systems, dry salt particles can be removed with common filtration practices (for example, use of high-efficiency filters, F9 or higher). However, removing salt that has dissolved into the moisture in the air is more complicated. The moisture in the air is present in two forms: as liquid water droplets and as water vapor (humidity). The majority of the liquid droplets can be removed with a coalescer or vane separator. These devices are effective for particles larger than 5 microns. The water droplet removal efficiency depends on the air velocity through the device. The remaining liquid droplets may make it to the high-efficiency filters. There are many high-efficiency filters that prevent water from penetrating the filter media, but not all filters have this capability. If liquid droplets are allowed to penetrate the filter media, then they can carry any absorbed salt downstream into the gas turbine. Gas turbines in high moisture and salty environments should have filter systems that minimize or eliminate liquid penetration. Water vapor cannot be removed by mechanical filtration. Any moisture in a vapor (or gas) form will travel through the filtration system into the gas turbine. However, a vapor at ambient conditions will most likely remain in the gas phase as it travels through the gas turbine.

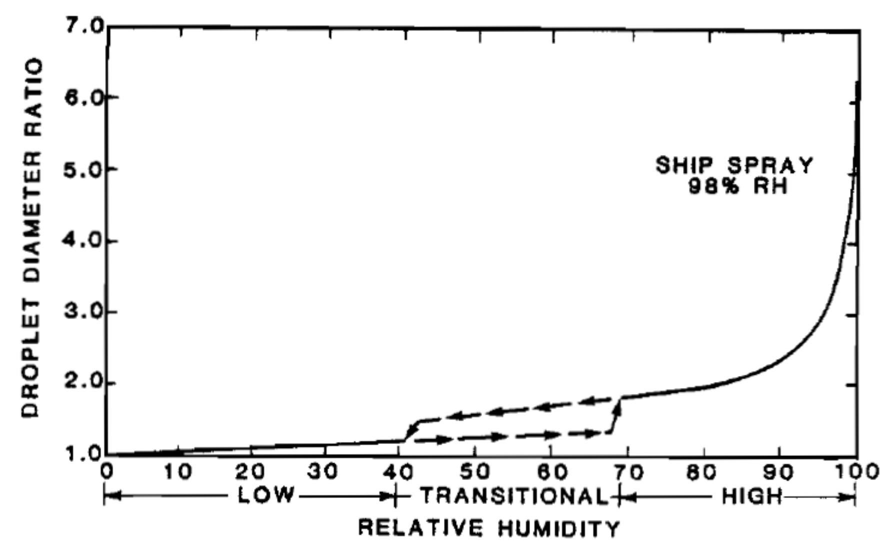


Figure F.17—How Sea Salt Particle Size Varies with Relative Humidity

Humidity plays a large role in the phase of the airborne salt and the size of the aerosol particles. Salt will exist in the dry state at a relative humidity below 40 % and in the wet state above 70 %. Anywhere between these two levels, the salt will be in a transitional state. Figure F.17 graphically represents how the aerosol particles change with changes in the relative humidity. The filtration system that is used to remove salt should be able to retain the salt in all possible states.

F.3.3 Filter Media

F.3.3.1 General

The material used on the filter to remove the particles from the air stream is referred to as the media. The type of media used in a filter strongly depends on the filter classification, use, and the filter vendor. There are many different types of filter media that are in use and being developed. Currently, there is no standard that regulates filter materials, so the filter vendor could utilize many different media types. A brief summary of the different types of filter media and their use is provided below.

The efficiency, dust holding, pressure loss, self-cleaning ability, and strength characteristics of the filter are controlled by the type and arrangement of the filter media. For good self-cleaning performance, surface loading media is used in self-cleaning filters. In this type of filter the high-efficiency layer is located on the upstream surface to prevent dirt imbedding into the media. The media also allows dust to form a surface dust cake that can be easily cleaned off. For long life static filters, the media should be graded such that different sized particles are captured throughout the media to optimize the dust holding capacity.

Filter media is manufactured in flat form and provided as roll goods. This flat media is generally cut to shape and sewn together to manufacture filter pockets, or is directly pleated into panels that are then assembled into filters. The selection of the type of filter media is not straightforward. There are some obvious benefits to the different types of media, but many parameters that will influence the filter media performance are not discussed below, including the presence of liquid or hydrocarbons, shelf life, impact resistance, wet burst pressure, and others. Sometimes various after-treatments are applied to filter media to improve performance in these adverse conditions. Filter vendors may have different perspectives of the advantages and disadvantages of the filter media materials. Some characteristics of the media often remain proprietary to the filter vendor. When selecting a filter system, it is important that the expected environmental conditions be clearly defined for the filter vendor to help select the proper filter media.

The filter media used in gas turbine inlet air filtration applications can be classified into six primary categories: natural, fiberglass, synthetic, membrane, blended, and composite. If the reader was to survey a variety of filter vendor's products, they would find that some or all of these media are available in gas turbine filters.

F.3.3.2 Natural Filter Media

Natural media is the oldest type and is comprised of substances that are found in nature, most commonly from wood and plant materials. There are two main sources of such fibers:

a) cellulose fibers, which are created in a similar way to producing paper, by making pulp out of the tree/ plant materials;

b) plant byproducts, such as cotton, which are naturally fibrous.

Cellulose media will have large fiber diameters (10 microns to 40 microns), resulting in lower filtration efficiency and lower dust holding capacities, higher pressure drop, and a shorter shelf life. Cellulose has a tendency to swell (making removal difficult) and also become weak when moisture is present, leading to pressure loss spikes. Even with these drawbacks, cellulose is still used frequently in gas turbine filter products. To overcome some of these drawbacks, it is common practice to blend cellulose fibers with a small percentage (10 % to 20 %) of synthetic fiber to make up the filter media.

F.3.3.3 Fiberglass Filter Media

Fiberglass is actually considered a synthetic media since it is not found in nature. However, it is listed separately because fiberglass is used in a large number of filter products. Fiberglass media is formed from a blend of natural minerals and manufactured chemicals and melted to form tiny fibers. These fibers are formed into flat roll goods that are used as the filtration media. The fiber diameter can range from the submicron to the micron size range. The word "microfiberglass" may be found on filter datasheets; this refers to fiberglass that has fibers in the submicron size range. Fiberglass can attain the highest levels of filtration efficiency and are most often used in high-efficiency filters to capture smaller particles. Fiberglass media has lower pressure loss and higher dust holding capacity than a 100 % natural fiber media.

Fiberglass fibers are brittle and break easily resulting in filter media that can be weak and delicate without a support structure. One advantage is that these fibers cannot be charged; therefore, the filtration efficiency that is measured in performance tests is similar to that in actual operation.

F.3.3.4 Synthetic Filter Media

Synthetic filter media is primarily made from polymers. There are many different types of, and manufacturing processes for, polymers. The process depends on the specific application, type of filter to be made and environment where it will be used. Synthetic fibers range in size from less than 0.5 microns to 20 microns and from a very thick media (up to 50 mm or 2 in.) to paper thin media. One of the advantages of synthetic media is the many different forms in which it is made and the ease by which it can be formed into composite media. The other advantage is that the synthetic media is generally much less sensitive to moisture than other types of media. Synthetic media can be, and typically is electrostatically charged. Therefore, care has to be taken when determining exactly what efficiency will be achieved in actual operation.

F.3.3.5 Membrane Filter Media

The membrane media is a very thin polymer film that has micropores typically in the range of 0.05 microns to 5 microns. Membrane media is sometimes used in higher efficiency filters and self-cleaning type filters. The fibers or fibrils are submicron in size. For gas turbine applications membranes do not have sufficient strength to be used alone and are always used within composite media. Membranes can be prone to rapid plugging from moisture and hydrocarbons; therefore, very careful design of the composite media is required.

F.3.3.6 Blends and Composites Filter Media

As seen above, the different media have advantages and disadvantages in terms of filter efficiency, pressure loss, and structural rigidity. Therefore, these media are often blended or combined to capitalize on the benefits and minimize the weaknesses. A blend is a filter media where two or more types of fiber are mixed. The most common blend seen in gas turbine filters is a blend of natural (cellulose) and synthetic fibers.

A composite refers to a filter media where multiple different types of fibers are layered. One example would be a media with a coarse fiber base synthetic substrate layer to provide strength and formability, followed by a fine fiber layer laminated to one surface of the base layer to provide high efficiency, and then possibly a third media layer laminated to the fine fiber layer to provide dust holding capacity.

F.3.3.7 Types of Filters

F.3.3.7.1 General

In order to meet the requirements of different operating environments, different types of filters have been developed.

F.3.3.7.2 Weather Protection and Screens

Weather louvers or hoods and screens are the most simplistic form of filtration. They reduce the amount of moisture and particles that enter the main filtration system. These components are not classified as filters, but they provide assistance in removal of large objects or particles carried in the air.

Weather hoods are sheet metal coverings on the entrance of the filtration system (see Figure F.18). The opening of the hood is pointed downward, so the ambient air has to turn upwards to flow into the filtration system. The turning of the air is effective at minimizing rain and snow penetration. Weather hoods and louvers are used on the majority of inlet air filtration systems and are essential for systems in areas with large amounts of rainfall or snow. In tropical climates, weather hoods deflect a large amount of rain, so the inertial separators (see F.3.3.7.3) are not overloaded and the amount of water traveling downstream is minimized.

Figure F.18—Weather Hood on Inlet Air Filtration System

Weather hoods used for rain deflection are smaller than ones used to deflect snow. The maximum recommended inlet velocity for minimizing rain ingress is 3.3 m/s (650 ft/min). Since snow falls at a slower rate than rain, the weather hood has to be larger. This larger hood increases inlet area which decreases the upward flow velocity. The maximum recommended face velocity for a weather hood with snow is 1.3 m/s (250 ft/min). In locations with snow, weather hoods have to be placed at an elevation well above the snow drifts. Weather hoods or other comparable weather protection systems are almost always required.

After the weather hood some systems have a series of turning vanes called weather louvers, which redirect the air so that it has to turn. The weather louvers can further reduce water and snow penetration. After the weather hood or louver is a trash or insect screen. Trash screens capture large pieces of paper, cardboard, bags, birds, leaves, insects, and other objects. If these pieces are allowed to enter the filtration system, they can obstruct the air flow through the filters. Screens that are installed specifically for blocking insects are referred to as insect screens. Insect screens will have a finer grid than trash screens. Trash screens and/or insect screens are used on the majority of filtration systems due to their simple construction and negligible pressure loss.

Environments with freezing rain or snow require special treatment. When ice forms or snow collects on filter elements, the flow area through the filter is reduced. This causes the flow velocity through the filter and the pressure loss to increase. Ice can also distort filter system or directly contact and damage the gas turbine. Figure F.19 shows an application where frost has collected on cartridge filter elements.

Anti-icing may be used to protect the filters from ice and snow (see G.2.3).

Figure F.19—Horizontal Cartridge Filters with Frost Buildup Due to Cooling Tower Drift

F.3.3.7.3 Inertial Separators

Inertial separation uses the density difference between air and particles to cause particles to be moved out of the gas stream in such a way that they can be carried off or drained. The higher momentum of the particles contained in the air stream causes them to travel forward, while the air can be diverted to side ports and exit by a different path. There are many types of inertial separators, but the ones commonly used with gas turbine inlet air filtration are vane and cyclone separators.

Vane axial separators are an axial flow device with hooks or pockets on the side-walls. There are two primary types: single pocket vane (or hook) and double pocket vane (see Figure F.20). As the gas turns along the vane, the water droplets impinge on the metal surface, are pushed to the pocket by the forces of the gas flow, and are then captured in the pockets. The closed pockets have a space for the liquid droplets to collect and drain out which reduces the potential for re-entrainment.

The single pocket vane type separators are effective for water particles greater than 10 microns. The double type pocket separators are also effective for capturing particles in the range of 5 microns to 10 microns. The efficiency of the separators is based upon the design air velocity. The separator will have the highest filtration efficiency at its design velocity. Vane separators have a pressure loss in the range of 25 Pa to 125 Pa (0.1 in. to 0.5 in. water). They are effectively used for removal of water in high-velocity filtration systems that are used in marine and offshore applications. The materials of construction should be suitable for the environment.

A cyclone separator is another type of inertial separator. This separator uses stationary blades to put the flow into centrifugal motion.

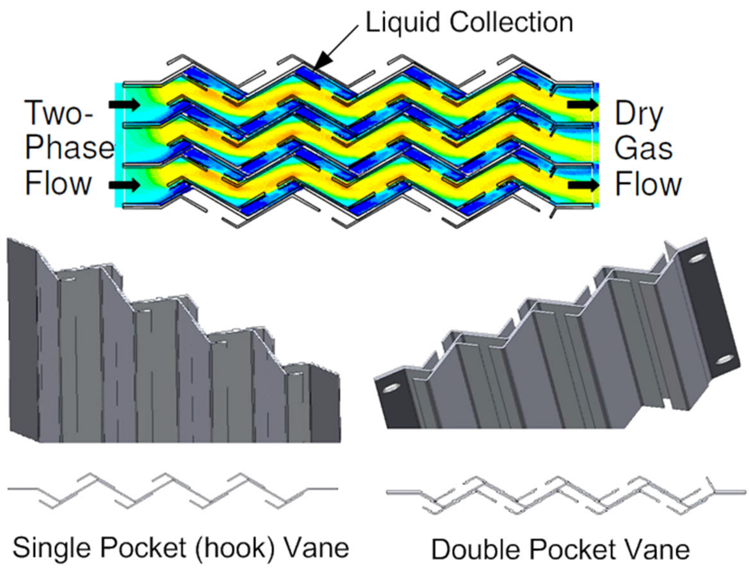


Figure F.20—Vane Axial Separators

F.3.3.7.4 Moisture Coalescers

In environments with high concentrations of liquid moisture in the air, coalescers can be used to remove the liquid moisture. The coalescer works by catching the small water droplets in its fibers and allowing them to conglomerate and either drain down the media or be released into the flow stream. If the larger drops are released, then they are captured downstream by a separator. Figure F.21 shows an example of how the droplet size distribution can change across a coalescer.

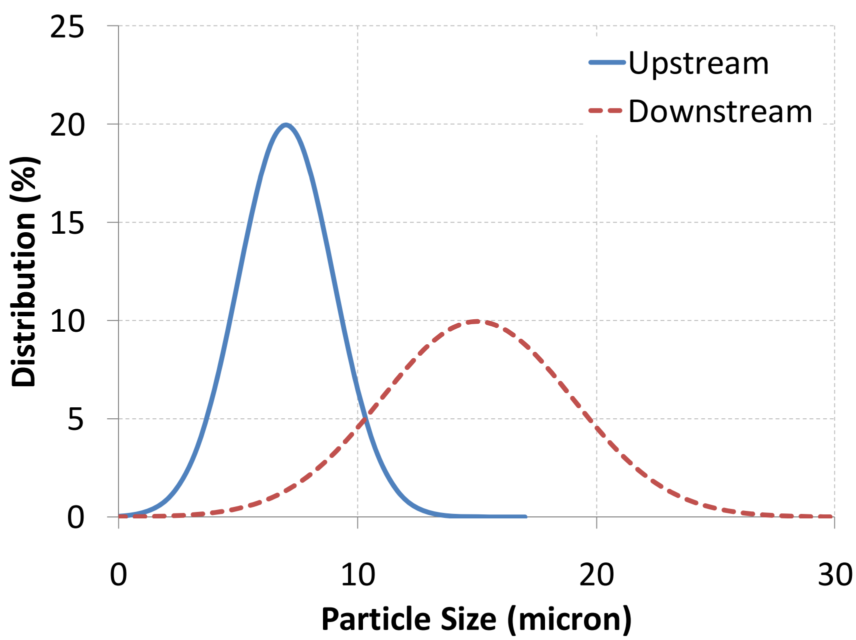


Figure F.21—Coalescer Droplet Formation Distribution

Many other types of filters are designed for solid particulate removal and not liquid droplet removal. The efficiency of the other filters can be significantly reduced if the filter becomes wet. The placement of coalescers is important. If the coalescer is placed too far upstream, then large particles that collect on the coalescer can travel downstream and decrease coalescer efficiency. However, placing the coalescer downstream of filters allows liquid droplets in the solid particle filters that will affect their performance. The solid particle filters have to stay dry to maintain their filtration efficiency. Therefore, coalescers are placed upstream of prefilters and high-efficiency filters.

F.3.3.7.5 Prefilters

The air has a mixture of large and small particles. If a one-stage high-efficiency filter is used, the buildup of large and small solid particles can quickly lead to increased pressure loss and filter loading. Prefilters are used to increase the life of the high-efficiency filter by capturing the larger solid particles. This allows the high-efficiency filter to remove only the smaller particles from the air stream that increases the filter life. Prefilters normally capture solid particles greater than 10 microns, but some capture solid particles in the 2- to 5-micron size range.

Pre-filters come in a number of configurations. These filters usually consist of large diameter synthetic fiber in a disposable frame structure. One example is a bag filter shown in Figure F.22. These offer higher surface area that reduces the pressure loss across the filter. Some other examples are panel filters, compact V filters, and socks placed around cartridge filters.

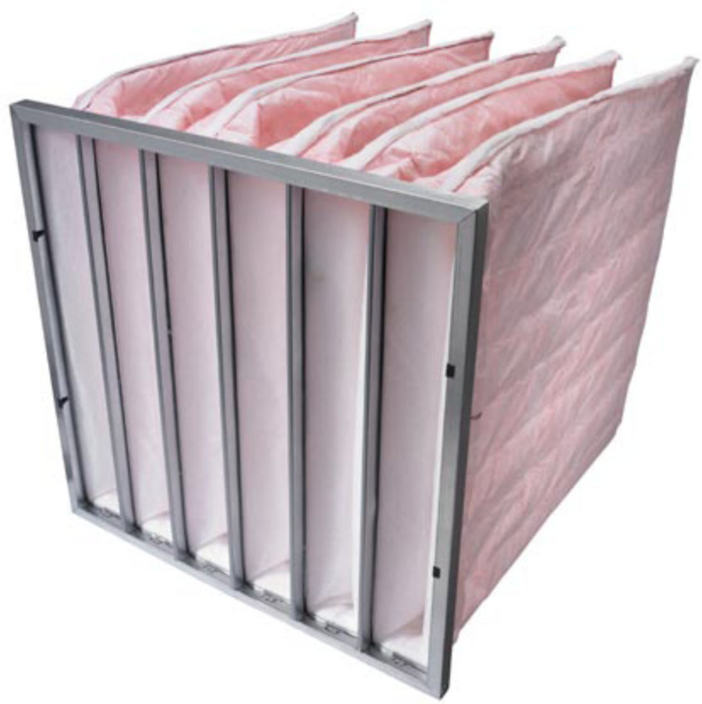


Figure F.22—Electrostatic Charge Filter

Sometimes an electrical charge is applied to the filter during manufacturing in order to increase the initial efficiency of the filter and decrease the initial static pressure values. Over time this charge neutralizes and the filtration efficiency for smaller particles will decrease with time. These electrostatic charged fibers have become commonplace in some pre and final filters. Testing submitted by filter manufacturers has to include efficiency values after the filter has been discharged of static charge providing a true mechanical efficiency value regardless of static charged fiber. Either EN779 or ASHRAE 52.2 with Appendix J will provide these final values of discharged filter.

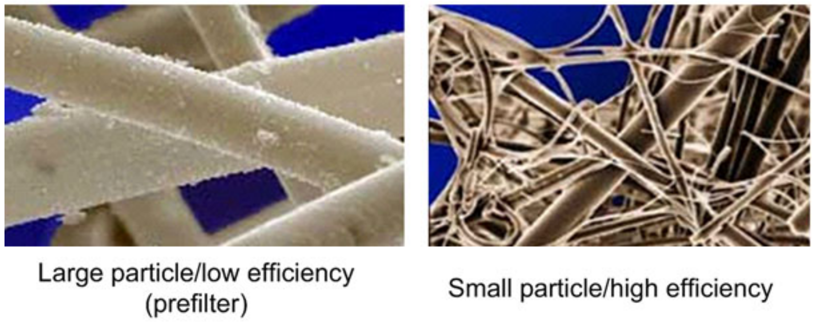


Figure F.23—Comparison of Fiber Structure for Low- and High-efficiency Filters

F.3.3.7.6 High-efficiency Filters

As discussed above, there are filters for removing larger solid particles that prevent erosion and FOD. Smaller particles that lead to corrosion, fouling, and cooling passage plugging are removed with higher-efficiency filters. Three common types of high-efficiency filters are EPA, HEPA, and ULPA. In the past, EPA and HEPA filters were not used with gas turbine inlet air filtration systems. Today, however, they are used in these systems to improve lifecycle performance and reduce the need for online and offline washing. Often, the term “high efficiency” is used loosely with discussion of gas turbine inlet air filtration. However, the majority of the high-efficiency filters used in gas turbine inlet air filtration are not classified as EPA, HEPA, or ULPA. F8 or F9, as defined by EN 779, filters are commonly used to remove small particles.

The high-efficiency filters used with gas turbines have pleated media that increases the surface area. In order to achieve the high filtration efficiency, the flow through the filter fiber is highly restricted that creates a high pressure loss. The pleats help reduce this pressure loss. Initial pressure loss on high-efficiency filters can be up to 0.32 kPa (1.3 in. water) with a final pressure loss in the range of 0.63 kPa (2.5 in. water) for rectangular filters and 1 kPa (4 in. water) for cartridge filters. The life of the filter is highly influenced by other forms of filtration upstream. If there are stages of filtration to remove larger solid particles and liquid moisture, then the higher efficiency filters will have a longer life. Minimal filtration before high-efficiency filters will lead to more frequent replacement or cleaning.

High-efficiency filter media are normally fiberglass, membranes, or synthetic fibers that are comprised of extremely large numbers of randomly oriented microfibers (as shown in the right image in Figure F.23). There are many different configurations of high-efficiency type filters: rectangular, cylindrical/cartridge, and pocket/bag filters.

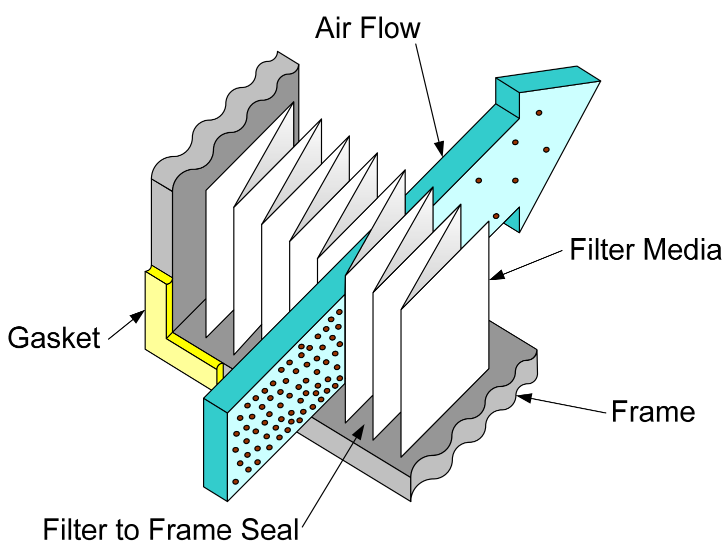


Figure F.24—Construction of Rectangular Pleated High-efficiency Filter

When installing a filter, the seal between the filter and the filter housing is critical (gasket shown in Figure F.24). This is true for all types (low and high efficiency) of filters. However, for high-efficiency filters, this seal is more critical due to the small sized particles being removed from the air stream.

Rectangular and pocket/bag filters are depth loaded filters; therefore, once they reach the maximum allowable pressure loss, they should be replaced. Both of these types of filters are installed in rectangular frames. A rectangular high-efficiency filter is shown in Figure F.25.

Figure F.25—Rectangular High-efficiency Filter

Cartridge filters typically have a higher dust holding capacity than rectangular filters. For example, a cartridge filter may retain twice as much ISO 12103-1 fine test dust compared to a rectangular filter. Cartridge filters are also made up of closely spaced pleats, but they are in a cylindrical fashion (see Figure F.26). Air flows radially into the cartridge. They are installed in a horizontal or vertical (hanging downward) arrangement. These types of filters can be depth or surface loaded. The surface loaded filters are commonly used with a self-cleaning system, but not all of them are designed for self-cleaning. A pre-filter sock is often placed around the outside of a cartridge filter. This helps to extend the life of the cartridge filter. Note that the sock should not be used with a self-cleaning filter. The sock will reduce the effectiveness of the self-cleaning mechanism.

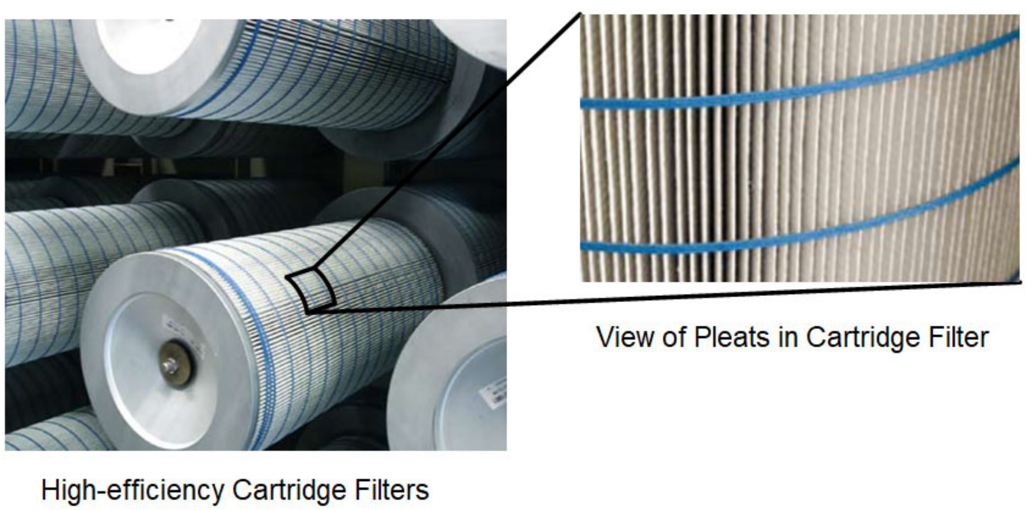


Figure F.26—High-efficiency Self-cleaning Cartridge Filters

F.3.3.7.7 Self-cleaning Filters

All of the filters with fiber type media previously discussed are required to be replaced once they reach the end of their usable life. In some environments, the amount of particles can be excessive to the point where the filters previously discussed would have to be replaced too frequently to meet the filtration demand. A prime example of one of these environments is a desert with sandstorms. In the 1970s, the self-cleaning filtration system was developed for the Middle East where gas turbines are subject to frequent sandstorms. Since then, this system has been continually developed and utilized for gas turbine inlet air filtration.

The self-cleaning system operates primarily with surface loaded high-efficiency cartridge filters. The surface loading allows for easy removal of the dust that has accumulated with reverse pulses of air (see Figure F.27). The pressure loss across each filter stage is continuously monitored. Once the pressure loss reaches a certain level, the filter stage is cleaned with air pulses. The pressure of the air pulses ranges from 550 kPa to 700 kPa (80 psi to 100 psi). The reverse jet of compressed air (or pulse) occurs for a length of time between 100 ms and 200 ms. To avoid disturbing the flow and to limit the need for compressed air, the system typically only pulses 10 % of the elements at a given time. With this type of cleaning, the filter can be brought back to near the original condition.

It should be noted that the filter elements in a self-cleaning system will degrade over time. This is due to the effects of some types of particulates captured by the filter, heat and the life of the filter media. Figure F.28 shows an example of how the performance of the filter degrades over time. In this example the self-cleaning slowly becomes less effective at reducing the pressure drop of the filter. Once the self-cleaning of a filter is no longer effective, it should be replaced. The filter should also be replaced once it reaches the material's maximum recommended life. Depending on the environment, cartridge filters in a self-cleaning system can have a life in the range of 1 to 4 years.

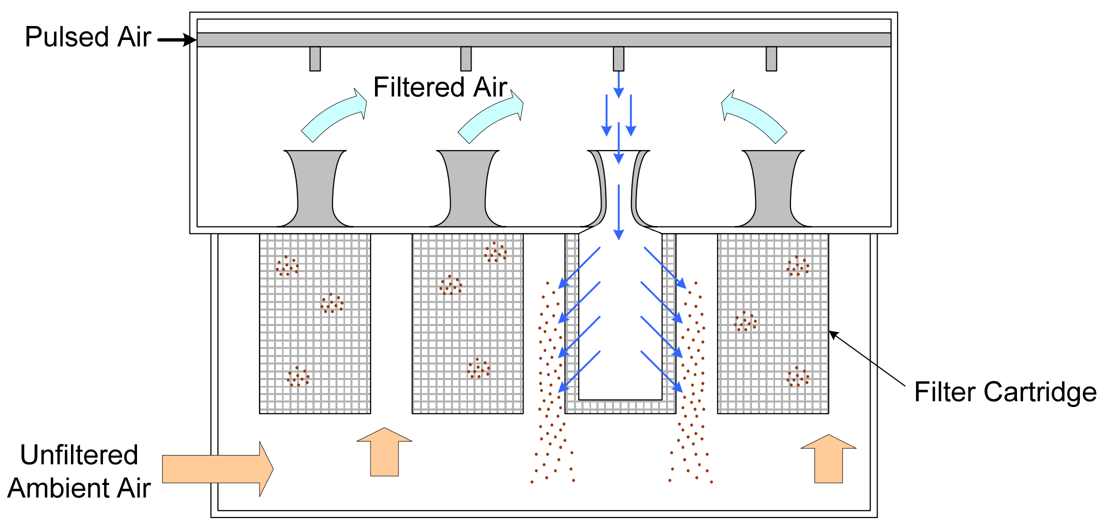


Figure F.27—Example of Operation of Updraft Self-cleaning Filters

These filters are constructed of specially treated cellulose, synthetic fibers, or a combination of both types of fiber. The filters used for self-cleaning systems have a mechanism that helps the filter retain its shape during pulsing and in normal operation. Cartridge filters used in self-cleaning applications require a more robust structural design than in static applications. There are several methods used to improve the structural rigidity of the cartridge filter. For example, a wire cage may be placed around the outside of the filter element or as shown in Figure F.26, specific fiber gluing techniques and outside fiber supports can be applied to increase the structural strength. The construction of self-cleaning filters is highly dependent on the manufacturer's design.

Self-cleaning filters are used in low-velocity systems. The low air velocity assists in preventing dust that is being removed from a filter with air pulsing from being re-entrained in the airflow stream, when normal flow is re-established. The efficiency of the filters actually increases over time. As the surface of the filter is loaded with particles, it decreases the available flow area through the filter that increases their efficiency. The environment where the filter system is operating will determine how quickly the efficiency increases. The pressure loss for cleaning is set based on the filtration system design and the design performance effects on the gas turbine.

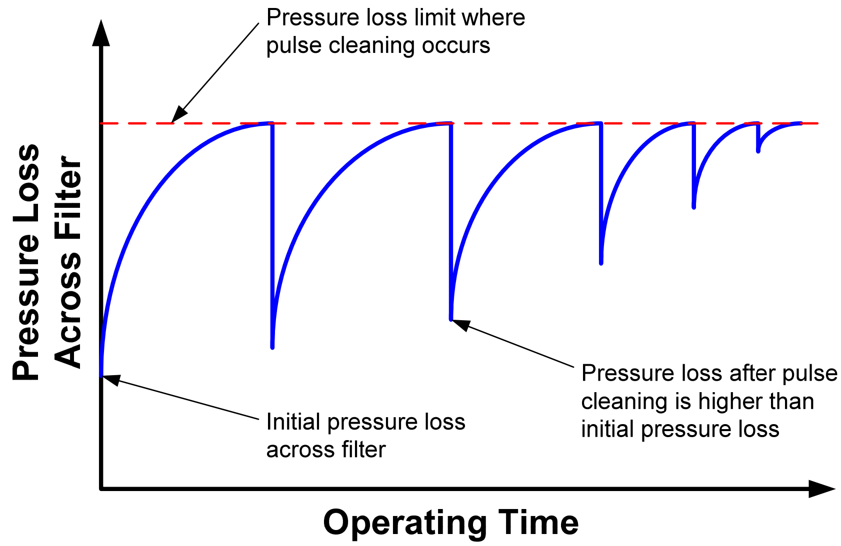


Figure F.28—Example of Pressure Loss Curve Over Time on a Self-cleaning Filter

Self-cleaning filters provide an attractive system for maintaining filter performance while controlling filter pressure loss, but they also have their disadvantages. This type of filtration system is useful in dry environments with high levels of dust. However, self-cleaning filter systems are not necessarily useful with medium or low levels of airborne particles. This is due to the fact that they operate on the basis of surface loading. The filter becomes more efficient as particles collect on the outside of the filter. In areas with low dust levels or small particles, the dust may actually be captured in the filter fibers. It is extremely difficult to remove particles that have penetrated the filters. These filters are not designed to operate as depth loaded devices. Also, these filters work poorly in environments with sticky contaminants such as pollen and hydrocarbons. Once the sticky substances have been captured by the filter, they cannot be removed with air pulses.

Self-cleaning filters are prone to high pressure losses and swelling, if they contain cellulose fibers, in high moisture environments. If particles that are captured on the filter media swell with moisture, then they will become very difficult to remove. Lastly, these types of systems are larger and more complex than the conventional system. However, this can be justified if they are used in an environment that would require frequent filter maintenance and replacement. Self-cleaning devices may require less filter maintenance, but the equipment on the system needs to be maintained itself. This equipment includes the solenoids, valves, and compressors that are needed to generate the air pulses.

Horizontal cantilevered cartridges when fully loaded can result in the seal becoming compromised and unfiltered air passing through. Horizontal cartridges usually require more frequent pulsing, due to re-entrainment.

F.3.3.7.8 Staged Filtration

Any gas turbine application typically needs more than one type of filter, and there are no "universal filters" that will serve all needs. Therefore, two-stage or three-stage filtration systems are used. In these designs, a prefilter or weather louver can be used first to remove erosive particles, rain, and snow. The second may be a low to medium-performance filter selected for the type of finer-sized particles present or a coalescer to remove liquids. The third filter is usually a high-efficiency filter to remove smaller particles less than 2 microns in size from the air. Figure F.29 shows a generalized view of a filtration arrangement. This arrangement is not correct for all cases due to the fact that the filter stages are highly influenced by the environment they are operating in. More examples of multistage filtration systems for different environments are summarized in F.3.4.3.

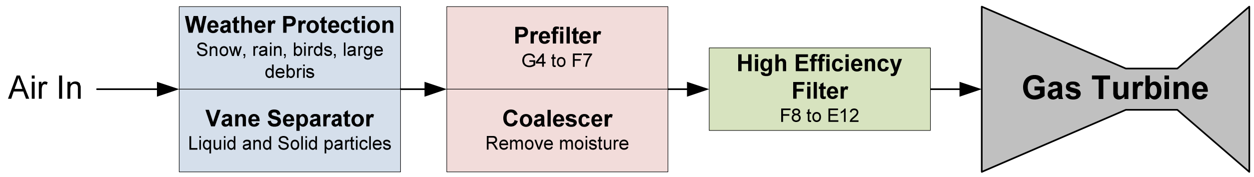


Figure F.29—Multistage Filtration System

Some of the things to consider when designing and selecting an inlet air filtration system are:

1) what types of particles need to be removed and at what efficiency;

   NOTE Site surveys and/or air sampling can be advantageous in establishing if there are detrimental site-specific sources (e.g. industrial, process) that are not obvious.

2) what loading characteristics are needed for the filtration system, will high amounts of water droplets be present, will water be allowed through the filtration system;

3) the expected face velocity;

4) what type of weather protection is needed for the system;

5) the required gas turbine availability and reliability;

6) the gas turbine fuel contaminants (if any); and

7) the gas turbine manufacturer's air quality specification.

Once this information is known, the number and type of filtration stages can be determined.

Figure F.30 shows two examples of arrangements for a gas turbine placed offshore. Both systems have weather hoods. The system on the left-hand side has a coalescer and vane separator to remove liquid in the flow stream. It is followed by a pre-filter and rectangular high-efficiency filter bank. The system on the right-hand side is for an environment with arctic type conditions. Immediately after the weather hoods is an anti-icing system followed by a vane separator, pre-filter, and high-efficiency cartridge filter bank.

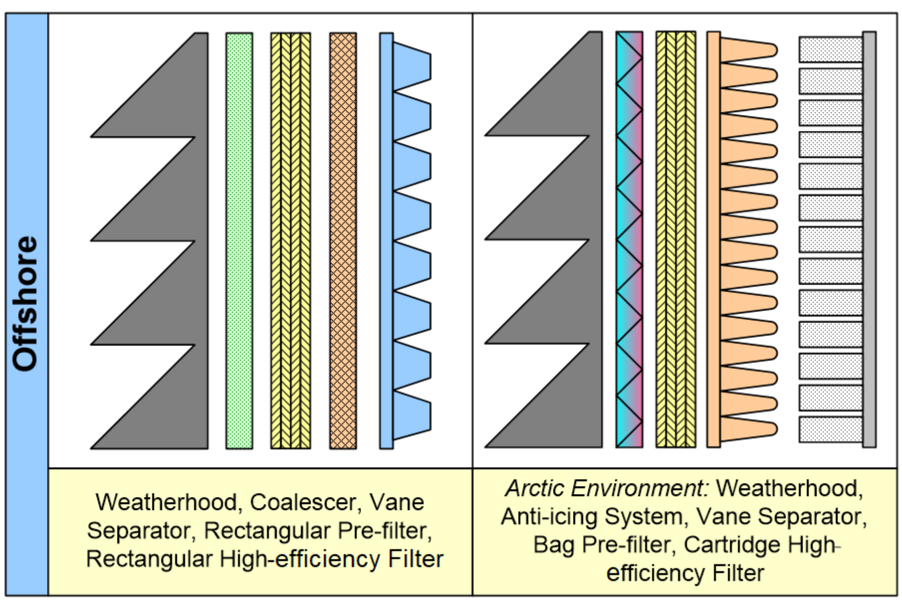


Figure F.30—Examples of Inlet Air Filtration System Arrangements for Offshore Gas Turbine

F.3.3.7.9 Structural and Ducting Design

Once the number and type of filtration stages has been selected, there are many other design features and considerations to be evaluated. Proper design of the filtration system structure and inlet ducting are as important as the selection of the filters themselves. Poor structural and ducting design can lead to leaks in system allowing unfiltered air to enter the gas turbine, material failures due to corrosion and wear, difficulty in conducting maintenance on filtration system, or poor performance of the gas turbine due to excessive pressure loss from poor inlet ducting aerodynamics.

The ducting should be designed to provide uniform flow and temperature distribution to the gas turbine inlet with low pressure drop. Nonuniform flow or temperature distribution to the gas turbine inlet can degrade performance of the gas turbine. Higher pressure drops, caused by sharp or unnecessary bends, also decrease gas turbine performance.

The internal components of the filter house and ducting can cause FOD. The systems should be designed to minimize the risk of fasteners, instrumentation, etc. from being able to come loose and enter the gas turbine, causing gas turbine damage.

The design of the inlet ducting and structure should consider the maintenance that will be necessary for the filtration system. This includes design of walkways, handrails, platforms, ladders, and inspection ports. Maintenance personnel should be able to easily access the filter elements for repair or replacement. The set-up should also consider access to filter elements for inspection during operation. If possible, inspection ports should be located to minimize the amount of unfiltered air which will enter the gas turbine during inspection procedures. Inspection ports should not be opened during gas turbine operation to prevent unfiltered air from entering the gas turbine.

Pressure relief devices are not used very often, but are occasionally installed on the filtration system in case of excessive pressure loss or if surge occurs in the compressor. These include negative and positive pressure releases. The negative pressure releases are usually implosion doors. These doors will open inward when the pressure loss across the filters reaches the maximum allowable difference [e.g. 2 kPa (8 in. water)]. The doors are designed to automatically release when a specified suction pressure is applied to them. Of course, when implosion doors open, unfiltered air will enter the gas turbine, but this will prevent damage to the filter housing structure due to high forces from increase pressure loss across the filter. These doors should also be set to alarm if they are opened. This will alert the operator that the pressure loss is high or that the doors have malfunctioned. Implosion doors require frequent inspection and maintenance to ensure there is no unfiltered air flowing through them.

Positive pressure doors (burst panels) or bladders (rubber or plastic transition pieces) are used to prevent structural failures of the filter housing or damage to the filters if the gas turbine surges. The pressure relief devices will open or break outward during a surge event to prevent high pressure spikes in the filtration system. These devices should have a relatively large area to adequately protect the filters. When installed they require frequent inspection and maintenance.

The location and orientation of the filter housing can have as significant of effect on the performance of the gas turbine as the local environment. Filter houses are usually placed 6 m (20 ft) off the ground, but a higher elevation may be necessary in locations with snow drifts or excessive dust. Placement of the inlet of the filtration systems in offshore applications should consider the expected wave heights and where the water and waves break on the installation. Figure F.31 shows a poor placement of an inlet of the filtration system on a floating production storage and offloading vessel. The filtration system is subjected to water spray from the flare and the ocean. Ideally, the filter housing should be placed so the prevailing wind is not blowing directly into the filtration system inlet; however, there are area classification issues that may drive a nonideal arrangement. This will assist in avoiding many of the particles carried through the air by the wind. Lastly, the inlet housing should not be placed in a location near process vents. Exhaust particles are typically very small and difficult to filter. If the inlet system has to be placed near vent, then this should be considered in the selection of types of filters. Ingesting flammable vapors into the inlet air system can cause a catastrophic gas turbine failure (see 7.7.2.1.5).

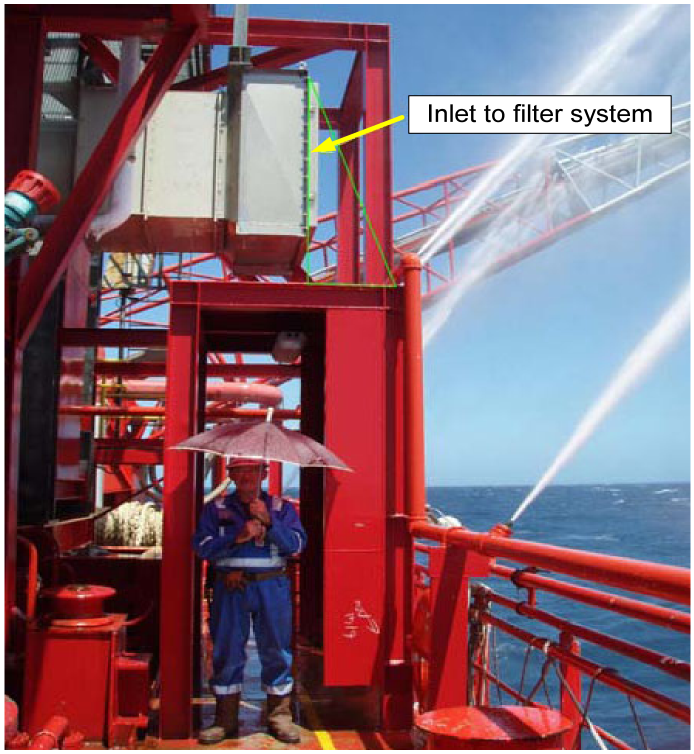


Figure F.31—Example of Poor Placement of Inlet to Filtration System

Because of the large sizes of inlet housings (especially in land-based applications), filter house and ducting are usually shipped in several modules. Modules that are clamped and sealed with gaskets and bolts should be aligned properly. Modules are sometimes welded together in the field. All bolted or welded joints should be checked for air leakage. These include framing gaskets and filters to frame gaskets. Leaks in the inlet housing system defeat the purpose of the filtration system and can cause gas turbine damage.

F.3.4 Application

F.3.4.1 General

Before a filtration system is designed and selected, criteria for the system has to be established. The areas that have to be considered in the filter system design are:

1) local environment;

2) inlet air quality criteria established by the gas turbine manufacturer;

3) maintenance strategies, including filter replacements;

4) offline or online washing;

5) time between overhauls;

6) desired uninterrupted operation hours.

The most important consideration for filter selection is the local environment. Both the contaminants existing in the local environment and manufacturer's required inlet air quality are used to determine the filter efficiency required.

The environmental conditions are constantly changing with the seasonal variations of local weather patterns or changes in the local area such as new construction or agricultural cycles. Even changes in the operational philosophy of the gas turbine itself can affect the inlet air filtration. Selecting the wrong system for the environment can mean more frequent filter changes, high inlet pressure loss, unscheduled shutdowns or turbine failures, and associated maintenance. Figure F.32 shows the differences in pressure loss for many different filters in different environments.

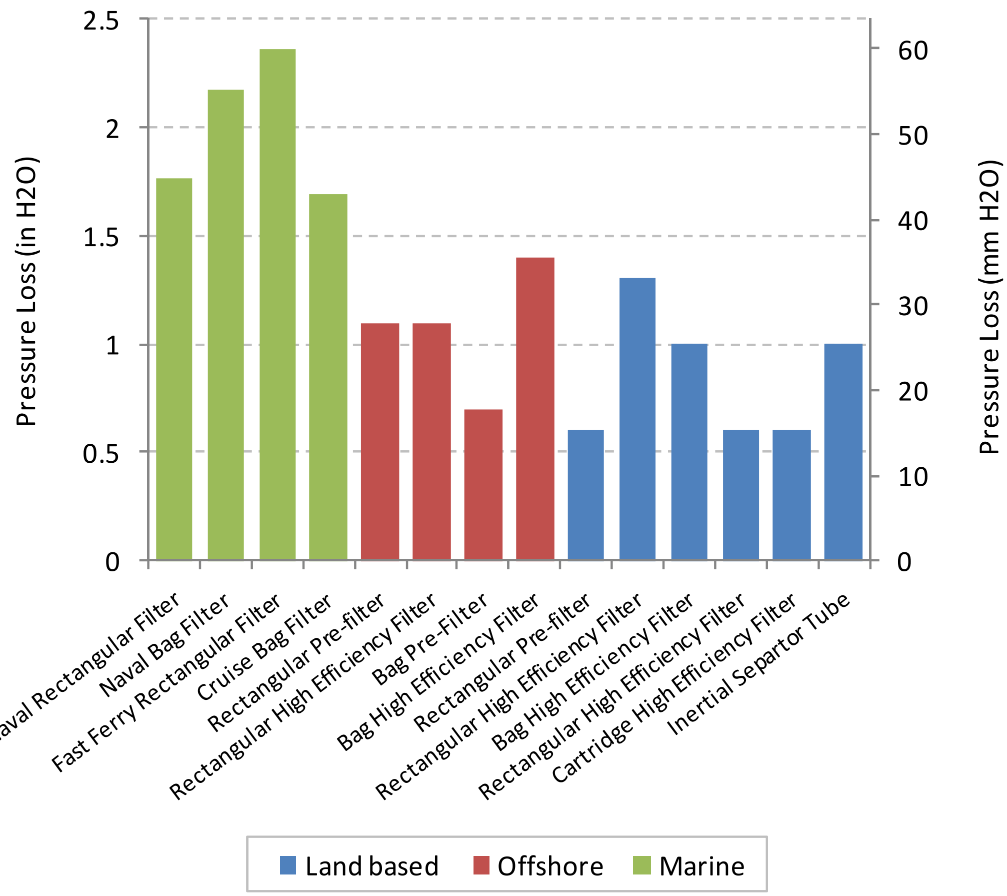


Figure F.32—Pressure Loss of Different Filters in Various Environments

F.3.4.2 Common Contaminants

F.3.4.2.1 General

Contaminants come from several sources including water (fresh or ocean), ground dust or vegetation, emissions, and weather events. Once these contaminants are released into the air, these particles are carried by wind currents from their source. Air turbulence patterns keep the contaminants aloft for a certain amount of time depending upon the settling velocity of the contaminant and wind speed. Due to weather and seasonal variations, the contaminants present are constantly changing. Some contaminants are present in environments on a long-term basis, such as ground dust. However, some contaminants will only be present during parts of the year (short term). For example, during the agricultural growing season, fertilizer particles may need to be removed from the air. Contaminants can be in the gas, liquid, or solid phase.

F.3.4.2.2 Gas Contaminants

Gas phase contaminants cannot be removed by mechanical filtration. Some examples of these contaminants are ammonia, chlorine, hydrocarbon gases, H_2S, SO_2, and discharge from oil cooler vents or local exhaust stacks. This category excludes contaminants that condense shortly after they are released forming aerosol droplets. Gas contaminants are only of a concern if they are released relatively near the gas turbine. As long as these contaminants remain in the gas phase and are present in small permitted quantities, they will not normally impact the gas turbine; however, in larger quantities some gases can cause damage (see E.6.6). However, if they interact with liquid contaminants, they can form corrosive compounds that can lead to degradation.

F.3.4.2.3 Liquid Contaminants

Liquid contaminants can range from aerosols to large droplets. Some common sources of liquid containments are cooling tower drift, sea water spray at coastal and offshore sites, condensation of moist exhaust plumes in cold weather, petrochemical discharges, rain, fog, and chiller condensates. The components contained in these contaminants that are detrimental to the gas turbine are chloride salts in water, nitrates, sulfates, and hydrocarbons. The first three mentioned are corrosive agents that can cause permanent damage to the gas turbine. Hydrocarbons can also contain corrosive agents, but may also lead to fouling of compressor blades.

F.3.4.2.4 Solid Contaminants

Solid contaminants are spread from their source carried by the wind. Heavier and larger particles drop out of the air stream quickly, whereas particles smaller than 10 microns will stay airborne a much longer time. Some common examples of solid particles are sand, ash, silica, road dust, dust from fertilizer and animal feed, airborne seeds, alumina, rust, calcium sulfate, and vegetation. Solid contaminants are removed with static or self-cleaning filters. The filters used to remove solid particles will not necessarily remove liquids or aerosols.

F.3.4.3 Applications Areas

F.3.4.3.1 General

The locations where a gas turbine is installed are classified into many different areas. This depends on the surrounding terrain or bodies of water, the weather patterns, and any specialized contaminant sources. Descriptions of the types of contaminants and filtration systems that are typically used are provided below for eight different applications including offshore, high chloride environment, desert, freezing environment, tropical, rural, urban, and industrial area. It is important to note that any gas turbine installation can be one or a combination of many of these different environments. All environmental conditions should be considered in the inlet air filtration selection.

F.3.4.3.2 Offshore

F.3.4.3.2.1 General

The offshore (fixed or floating) environment is subject to wet and dry salt particles and other contaminants. Corrosion is a common concern with the presences of salt, but the gas turbine also experiences significant fouling issues. Compressor fouling has been reported to be the reason for 70 % to 80 % of the performance degradation on offshore gas turbines. In addition, size and weight restrictions and motion are usually important considerations.

F.3.4.3.2.2 Offshore Contaminants

Offshore gas turbine inlet air filtration systems have a diverse range of contaminants that need to be removed. The most prevalent contaminant is salt. Salt aerosols are naturally present from the agitation of the seawater and waves breaking. The concentration of salt depends on how close the gas turbine air inlet is located to the ocean surface. The amount, type, and size of the salt aerosols or dry particles changes with the wind direction, humidity, and weather. In some offshore locations, significant gas turbine performance degradation has been reported after foggy weather. Fog aerosols are often too small for water separators to collect. The coalescer may capture some, but often these aerosols will gather on the pre-filter or high-efficiency filters. This can lead to an increase in pressure drop in the filter system until the filters dry out.

An offshore oil and gas facility is an industrial plant in a high chloride environment. This environment comes with all the expected plant type emissions. This includes hydrocarbons, soot from exhaust and flares, vapor from oil tanks, drilling dust, paint fumes, and particles from maintenance activities such as grit blasting. The inlet air filtration system will need to operate in rain or dry conditions. Depending on the location of the offshore operation, the inlet air filtration system may also need to operate in dust storms or haze from local coastal regions or freezing conditions. In most offshore locations, the dust concentrations will be in the range of 0.01 ppmv to 0.1 ppmv (dry), particles from 0.01 microns to 5 microns in size.

The offshore environment has some typical long-term conditions such as the presence of salt, but consideration should be given to potential short-term conditions such as dust storms, grit blasting, and freezing weather conditions.

F.3.4.3.2.3 Offshore Filtration System

In offshore locations, the filtration system has to remove particles to prevent fouling and remove moisture and salt to avoid corrosion. These systems will typically have a combination of a water removal system (vane separator and coalescer) and high-efficiency filtration system. If the environment has a high dust concentration (local dust storms or dust haze), then a pre-filter may be used to remove the larger particles and extend the life of the high-efficiency filter. Due to the large amount of salt and moisture present in this environment, corrosion protection is highly important on the metal components of the filtration systems. Medium- and high-velocity systems are commonly used in offshore locations due to size and weight restrictions.

F.3.4.3.3 High Sodium Chloride Environment

F.3.4.3.3.1 General

In addition to offshore applications, there are many land-based locations that have a high concentration of sodium chloride in the air. Some common examples include near an ocean shoreline (coastal) or next to a dry salt bed. Sodium chloride or salt is important to consider because it contributes to corrosion in both the compressor and hot sections of the gas turbine.

F.3.4.3.3.2 High Sodium Chloride Environment Contaminants

In a high chloride environment, there are three containments that are of concern: sodium chloride, water, and exhaust gases containing sulfur. The mixture of water and sodium chloride contribute to pitting corrosion in the compressor section of the gas turbine. The fuel quality is also important in a high chloride environment. Sulfur (from the fuel) and sodium (from air) can combine in the hot section of the gas turbine to initiate hot corrosion.

Locations near the ocean shoreline (coastal) are usually subject to high salt concentrations. These locations are important because they have both high amounts of salt and water. Also, the humidity is typically continuously high. The high salt and water conditions make it challenging to prevent salt from entering the gas turbine and avoiding corrosion.

Dry lakebeds are a potential source of airborne salts particles. They can be found in dry desert climates. Since there is little water near these locations, corrosion in the compressor section is not of high concern. Inland salt lakes tend to have the same effects as the seawater near the ocean. A few distinct differences are that there will be fewer aerosols generated due to wave action, and the higher saline concentration of the water will increase the salt in the air due to evaporation.

F.3.4.3.3.3 High Sodium Chloride Environment Filtration System

The type of filtration system used in a high sodium chloride environment will depend on the other contaminants that are present. Solid salt particles larger than one micron are not difficult to remove with filtration systems, but wet or sticky salt particles are challenging. In high salt and water environments, an upstream liquid removal system is important. This system can include coalescers and vane separators. High-efficiency filters are used in these environments to remove the smaller salt particles. If water or high humidity is present, then the high-efficiency filters should be made of hydrophobic media. This will minimize the amount of salt that can wash through the filter and downstream into the gas turbine.

Sulfur particles from exhaust stacks are typically smaller than one micron and therefore are difficult to remove. Sulfur ingestion is best minimized by placing the gas turbine inlet away from the exhaust stack's stream.

F.3.4.3.4 Desert

F.3.4.3.4.1 General

The desert is a unique environment that is characterized by dry climate with long sunny periods, high winds, sand and dust storms, and occasional heavy rains. The main regions of the world which can be characterized by desert like environments are across the Sahara Desert in Africa, the Middle East, and parts of Asia. However, small localized areas with high dust concentrations do exist. These can include gas turbines installed near quarries, dried lakebeds, industrial areas, dirt tracks, dry agricultural land, and construction sites. Figure F.33 shows the dust concentration across the world highlighting the major dust areas.

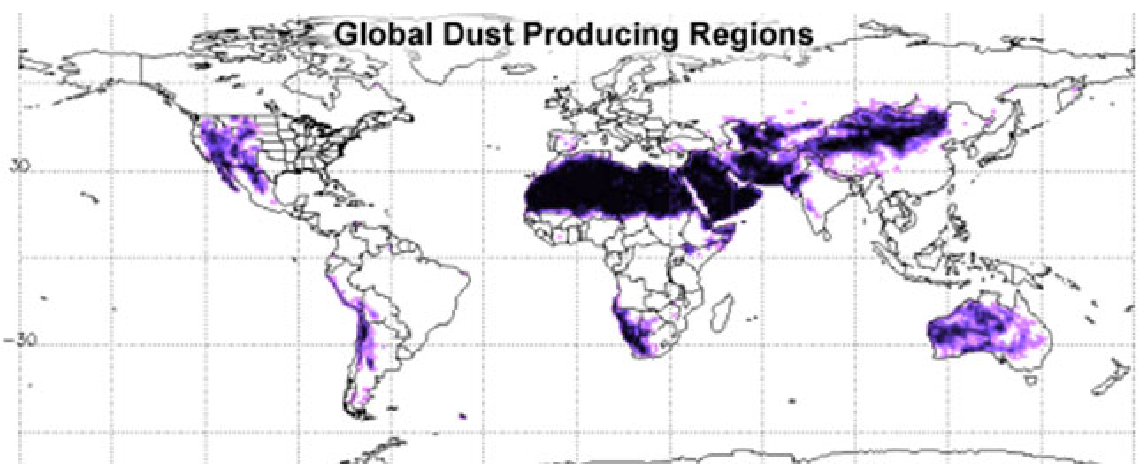


Figure F.33—Areas of the World That Have High Dust Concentration

F.3.4.3.4.2 Desert Contaminants

There are three typical conditions that exist in the desert: clean air, dust haze, and sandstorms. Table F.4 describes the contaminant sizes and levels that can be experienced during these three events. Dust is the main contaminant in the desert for these conditions. This can be sand or other fine-grained material such as desert pavement. Dust can range in size from large particles near 500 microns to submicron in size. Due to the lack of vegetation and protection of the ground dust from the wind, more dust can be lofted into the air than in other environments. This leads to a high concentration of dust.

Table F.4—Typical Desert Conditions

Condition	**Contaminant Level** ppmv	**Average Contaminant Level** ppmv	**Particle Size** microns
Sandstorm	3 – 118	59	5 – 15
Dust haze	0.15 – 3	1.5	1 – 3
Clean air	0.15	0.15	0 – 1

Large amounts of dust combined with high winds can combine to transport dust from these environments to the surrounding areas. Turbulent air activity will keep the dust aloft, and the wind can transport the dust far away from the source. The closer a gas turbine installation is to a dust source, the higher potential for larger particles and higher concentration, since the dust has not had as much time to settle out. There are seasonal winds and storms around the world that can transport dust up to hundreds of miles (e.g. African harmattan and chamsin/khamsin, Iraqi and Persian shamal, Australian brickfielder/bricklayer, southern United States haboob, and Mediterranean sirocco). All of the winds and dust storms mentioned can easily plug the filtration system with large erosive dust.

Figure F.34—Texas Haboob

Some desert locations experience periods of dense fog and high humidity. This is especially true for deserts near a coastal region. The moisture can collect on the surface of cartridge filters on self-cleaning systems and cause the dirt to form a cake on the filter. This cake of dust can significantly reduce the effectiveness of the self-cleaning. However, self-cleaning systems are often still needed to handle the high dust load. If fog and high humidity are present at the desert type site, then this should be considered for the design of the filtration system.

F.3.4.3.4.3 Desert Filtration System

Dust loads in the desert can range from mild (low wind) to fairly high (dust storms). Conventional non-self-cleaning filtration systems can quickly become loaded and require frequent filter change outs. Also, high pressure losses can trigger a shutdown if they become excessive. In order to avoid the constant maintenance and labor required for changing filters out, a self-cleaning system is often used.

High-efficiency cartridge filters are used with self-cleaning systems. The self-cleaning systems are very effective, especially during a sandstorm. They keep the pressure loss below acceptable levels by constant cleaning without any interaction of the gas turbine operator. This allows the gas turbine to continue to operate at an optimal performance even during adverse conditions. As discussed above, if the environment has high humidity, fog, or moisture or contaminants with sticky particles, a dust cake can form on the filter. Moisture coalescers, self-cleaning filter media selection, pulse operation, and lowering filter media velocities are often used to reduce the likelihood of the dust cake formation.

F.3.4.3.5 Freezing Environment: Snow, Ice, and Frost

F.3.4.3.5.1 General

The freezing environment is highly influenced by prevention of ice formation/buildup and removal of snow. This environment is characterized by temperatures near or below 0 °C (32 °F) or with snow, ice, or frost. The locations may also be classified as another type of environment during the year depending on the seasonal changes.

F.3.4.3.5.2 Freezing Environment Contaminants

Ice buildup on the filtration system or inlet to the gas turbine is the main concern in the freezing environment. Ice forms primarily in two ways. The first is the most obvious, through ingestion of snow or freezing rain. The frozen precipitation accumulates on filtration system components and forms blocks of ice. Snow is typically dry due to low ambient temperatures, but wet snow can also occur. Wet snow is more detrimental to an inlet system, since it has a sticky consistency. If ingested, it can easily accumulate on inlet components. Blowing snow can quickly cause ice accumulation.

The second method of ice buildup is depression of cool humid air in the inlet system. When the air velocity increases across the inlet system, the pressure decreases, which causes a simultaneous decrease in temperature. Any moisture in the air can freeze and collect on inlet system components. This type of ice formation can occur on the filters, inlet ducting, or at the bell mouth of the gas turbine. The moisture can be due to ice fog, ice crystals in humid air, and cooling tower drift.

The ice accumulation at the inlet to the gas turbine reduces the surge margin of the compressor by decreasing the inlet pressure of the compressor. Also, if the ice accumulates past the filtration system pieces of ice can break off and be ingested by the gas turbine causing FOD. Aeroderivative engines are the most susceptible to this due to their higher temperature depression, lighter compressor blading, and lower surge margin.

F.3.4.3.5.3 Freezing Environment Filtration Systems

There are three primary components of the filtration system for the freezing environment: initial weather hood or weather louvers, anti-icing system, and filters. The weather hoods are designed with a lower inlet velocity in order to mitigate the ingestion of snow or freezing rain. This decreases the likelihood that snow will be pulled upwards into the filtration system. The dry crisp snow in the freezing environments makes the use of inertial separators possible. These can be used as a first-stage snow filtration for the system but may be troublesome in areas with heavy snow.

The design or layout of the surrounding equipment near the inlet should be considered carefully. Wind deflection structures can be used to help minimize snow ingestion into the filtration system, but if done incorrectly, it can make the snow ingestion worse. Anti-icing systems are often used if inlet compressor icing is a concern.

Conventional non-self-cleaning filtration is susceptible to icing. Self-cleaning has been effective in preventing ice buildup. The self-cleaning filters operate well when the snow is dry and crisp. With wet snow and ice, both self-cleaning and static filters can quickly become loaded and have elevated pressure losses. Wet or damp filters should never be installed in any filtration system in the freezing environment.

The inlet filter housing should be elevated to minimize the ingestion of snow or freezing rain. Consideration should be given to the expected height for snow drift and accumulation of snow (see 7.7.2.3.18). This includes a review of near-by buildings walls and equipment that may lead to snow buildup.

F.3.4.3.6 Tropical

F.3.4.3.6.1 General

The tropic environment is characterized by hot climate, high humidity, monsoons, high winds, and insect swarms. Due to the extensive vegetation, there is not much erosion concern. The area has little seasonal variation with the exceptions of periods of intense rainfall. Typhoons, dust, insects, and the remoteness of systems in the tropics should be considered when choosing the correct filtration system.

F.3.4.3.6.2 Tropical Contaminants

The main contaminants in this area are water and insects. Dust is lower in this environment, since the overgrown vegetation protects the ground dust from winds. If the gas turbine is installed in a construction site, then the dust levels will be higher than normal. Unpaved roads can contribute to the dust in the environment. Pollen can be an issue. In coastal areas, salt will often be present in aerosol form due to the high humidity and moisture present.

Large insects and moths may occur in large quantities in this area, particularly during their breeding periods. They are attracted to lights that often surround gas turbine installations. Also, the pull of the air to the gas turbine inlet draws the moths or insects onto the insect screens. In some instances, this can cause the gas turbine to trip.

The tropical environment experiences frequent rainstorms. High winds can cause “horizontal” rain. This phenomenon makes the use of weather hoods less effective. The humidity or moisture in the air is usually very high (above 70 % relative humidity).

F.3.4.3.6.3 Tropical Filtration System

The filtration systems for tropical environments are specifically built to handle large amounts of rain. Weather hoods are often used to house insect screens and mist eliminators. Extended area insect screens are used and have a lower air velocity [in the range of 1.3 m/s (250 ft/min)], which allows the insects to move away from the screens. This is followed by a mix of pre-filters, coalescers, and vane separators. The water removal system has to be designed in order to handle the highest expected water ingestion to prevent water carryover. All filters should be selected for a wet environment. These filters should also be selected for the expected contaminants such as pollen and road dust.

The high temperature in combination with the high humidity leads to the accelerated formation of mold, fungus, and corrosion. Corrosion can quickly spread and damage any nonprotected inlet components. Therefore, it is essential that all metal inlet parts be made of corrosive resistant materials or coated with corrosion protection. The use of synthetic filter media can help to avoid the growth of mold and fungus.

F.3.4.3.7 Rural

F.3.4.3.7.1 General

The rural area is a diverse environment. The gas turbine can be subjected to hot, dry, cold, rain, snow, and fog throughout the year. The area can be near a local forest or near agricultural activities.

F.3.4.3.7.2 Rural Contaminants

The contaminants in this environment vary depending on the season. If the gas turbine is installed near an agricultural area, then during plowing and harvesting season, the concentration of dust will increase. During plowing, insecticides and fertilizers, which are corrosive, will be airborne. At harvest, the particles or grains from cutting plants down will be lofted into the air. The particles that travel to the gas turbine may be smaller than 10 microns.

Gas turbines near forests may not have as high dust concentration. The foliage of the forest will protect the ground dust from being lifted by the wind. Depending on the season, snow, rain, fog, pollen, airborne seeds, insects, and high humidity may be present.

F.3.4.3.7.3 Rural Filtration Systems

Weather hoods are used as a first defense. Insect screens are included to protect against insect swarms and foliage. Last are multiple filter stages typically including a pre-filter, secondary filter, and final filter.

In agricultural areas, a self-cleaning system may be used. This type of system would be beneficial during plowing or harvest season when the air has a high dust concentration.

F.3.4.3.8 Urban

F.3.4.3.8.1 General

An urban area has a mixture of fine contaminants that can be corrosive and lead to fouling issues. The diverse environment mandates the use of a multistaged filtration system.

F.3.4.3.8.2 Urban Contaminants

All different types of weather can occur throughout the year in an urban area. The amount of contaminants varies depending on the season. During the winter, salt or grit that is laid down on icy roads can create particulates in the air.

The particulates in the air are typically comprised of smaller particles (submicron to 5 microns) and may be corrosive gases. It depends on what is installed near the inlet system. If the gas turbine is near power plants or other industrial facilities, then there will be hydrocarbon aerosols and sooty and oily dust particles in the air. This area includes smog and pollution, which have to be considered in the filtration system selection.

F.3.4.3.8.3 Urban Filtration System

The system for the urban area has a multistage approach with specific filters installed for the local contaminants. Weather hoods are used the majority of the time due to the changing weather conditions with seasons. The filtration system is composed of multiple filter stages. The high-efficiency filter is typically of the non-self-cleaning type. The self-cleaning systems are not used due to the sticky aerosols present in the air. Urban/industrial areas typically do not have airborne particulate concentrations that warrant the use of self-cleaning filtration systems. If the region has heavy snow, a self-cleaning system may be used.

F.3.4.3.9 Industrial

F.3.4.3.9.1 General

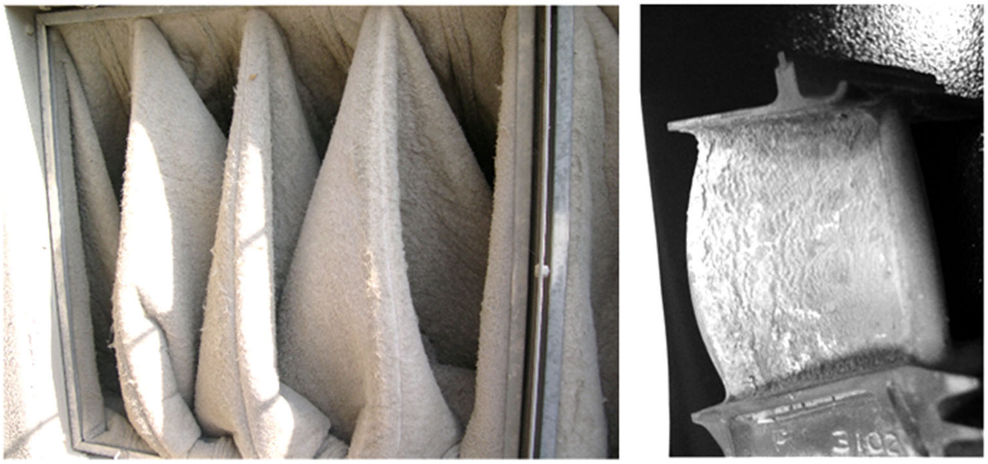
Many gas turbines are installed in heavy industrial areas. These locations can be in any of the environments discussed above, but they have additional concerns. There can be many emission sources in an industrial location, which contribute to the contaminants in the air.

F.3.4.3.9.2 Industrial Contaminants

The most prevalent contaminants in industrial areas are from exhaust stacks. These contaminants can be in the form of particles, gases, and aerosols. Many of the particles emitted by the exhaust stack are in the submicron size range. These size particles are difficult to filter and can collect on compressor blades and cause fouling. The gases emitted in the exhaust can contain corrosive chemicals. For example, exhaust gases from fossil fuel plants have SO_X which contains sulfur. As discussed above gas cannot be removed by mechanical filtration. Aerosols also present a challenge. These are typically on the submicron size and difficult to filter. Many of these aerosols are sticky, and when they are not removed by the filters, they stick to compressor blades, nozzles, and other surfaces.

Industrial locations can also experience localized contaminants. Some examples of these are dust from mining operations, sawmills, foundries, and other industrial facilities. Also, if the gas turbine is near a petrochemical plant, the air may be contaminated with specific chemicals. These chemicals often have corrosive properties.

One example of a unique emission source in an industrial location is shown in Figure F.35. It shows a bag filter and a turbine blade at a soda ash plant. The initial filtration installed for this facility only had one stage of filtration that was not able to handle the limestone dust that was prevalent in the air. As a result, the turbine blades were damaged several times during the initial operation.



Bag filter loaded with limestone dust

Turbine blade with thick deposits of limestone dust

Figure F.35—Bag Filter and Turbine Blade at Soda Ash Plant

F.3.4.3.9.3 Industrial Filtration System

One commonality between all industrial locations is that the inlet of the filtration system is subjected to the local plant emissions. This condition typically requires a more robust high-efficiency filtration system to remove fine particles that are entrained in the air. One way to reduce the amount of emissions that are ingested into the inlet is to direct the inlet air flow away from these emission sources. Site layout recommendations are discussed later. Even so, there are some emissions that are ingested by the gas turbine. A multistage filtration system with pre-filter, secondary filter, and final filter should be used to remove these fine particulates.

F.3.4.3.10 Other Applications and Considerations

F.3.4.3.10.1 General

Localized emissions sources that affect the operation of the gas turbine should be considered in the design of the filtration system.

F.3.4.3.10.2 Winter Lake Effects

At locations with large lakes, in early winter large quantities of snow may fall in a period of a few hours. The winter lake effect is dependent on the distance from the lake shoreline, time of year, lake temperature, wind direction, and wind strength. To minimize snow or ice ingestion, the gas turbine inlets should be positioned away from the direction of prevailing winds in late autumn and early winter.

F.3.4.3.10.3 New Emission Sources

During the life of the gas turbine, there is the likelihood that a new emission source will develop. This could be nearby construction activity, change in local industrial activity, or change in agriculture activity. These should be considered in the protection of the gas turbine and their effects on life and performance.

F.3.4.4 Site Layout

F.3.4.4.1 General

The layout of the site where the gas turbine is installed can have a significant effect on the type and amount of contaminants that need to be removed from the inlet air. Listed below are general recommendations for equipment placement.

F.3.4.4.2 Exhaust and Vents

When installing combustion type equipment near the gas turbine, such as a diesel engine, the exhaust of the equipment should be directed away from the gas turbine inlet. This reduces the possibility of the exhaust gas entering the gas turbine inlet system. This exhaust can contain UHC or corrosive gases.

The exhaust of the gas turbine should be directed away from the inlet of the gas turbine. Carbon smoke and hydrocarbon fumes may be released at the exhaust and could lead to accelerated fouling of the compressor blades.

Lube oil vents should be directed away from the inlet to prevent oil vapor ingestion. Also, vents from pressure relief devices should be directed away from the gas turbine inlet. Release of any hydrocarbon could result in high concentration of hydrocarbons entering the filtration system (see 7.7.2.1.5). The filter material may be susceptible to plugging from hydrocarbons. Hydrocarbons entering the inlet system may also cause over-speeding of the gas turbine.

F.3.4.4.3 Cooling Towers

Cooling towers can be a major source of aerosol drift. The water in the cooling tower contains water treatment chemicals that could be detrimental to the gas turbine. The drift of aerosols from a cooling tower is normally confined within a few hundred feet. If possible, the gas turbine inlet should be positioned away from cooling towers and placed upstream of the prevailing wind direction to minimize the aerosol drift.

F.3.4.4.4 Piping Connections

Piping connections may leak. The leaks at these connections can impact the filtration system. Piping connections should be located away from the inlet to the filtration system (see 7.7.2.1.5).

F.3.4.4.5 High Dust Concentrations

The dust thrown into the air from vehicle traffic and wind can be carried into the inlet of the gas turbine. When practical, direct the inlet to minimize dust ingestion from this source. If the gas turbine is operated during construction activities, consider adding more robust filters to remove the excess dirt that will be ingested. Direct the inlet away from any open storage of coal, salt, or other grainy particles.

F.3.4.4.6 Temporary Filters

In many of the applications discussed above, temporary (maintenance and construction) or seasonal conditions can occur. The majority of the filtration systems installed do not use temporary filters. However, if the site for the gas turbine is expected to have high variability in the type of contaminants experienced (temporary or seasonal), a filtration system which allows the use of many different filter elements may be considered. This would then allow the filtration system to be adapted to the current conditions. The expected conditions are first defined to identify an appropriate temporary filtration system. During the design phase, the air quality at the site where the gas turbine is going to be installed should be evaluated for site conditions and surrounding area over a full year to account for seasonal changes. Also, any potential construction, maintenance, agricultural, or temporary high particulate conditions that may occur during operation should be considered. Temporary filters would include pre-filter socks for cartridges and open-weave fiber clothes draped over or inside the weather hoods.

Annex G
(informative)

Gas Turbine Inlet Air Heating and Cooling

G.1 Gas Turbine Inlet Cooling

G.1.1 General

Inlet cooling and water injection technologies for gas turbines are less common; however, because of performance advantage of these technologies, a large number of systems have been installed. Gas turbine output is inversely proportional to inlet air temperature with power output dropping by 0.5–0.9 % for every 1 °C (0.3–0.5 % per 1°F) rise. Industrial gas turbine power output can drop around 20 % from ISO conditions, at 35 °C (95 °F) inlet air temperature, coupled with a heat rate increase of about 5 %. Aeroderivative gas turbines exhibit even greater sensitivity to inlet air temperature.

Gas turbine inlet cooling reduces the inlet air temperature into the gas turbine and thus increases its output power and decreases its heat rate. This is shown for a typical gas turbine in Figure G.1.

Most gas turbine inlet cooling systems create a pressure drop that reduces gas turbine power output and increases the heat rate. This pressure drop exists even when the cooling system is not in use. The net benefit of gas turbine inlet cooling systems should be evaluated. Ensure that on hot days the generator rating matches the higher power input from the gas turbine with inlet cooling.

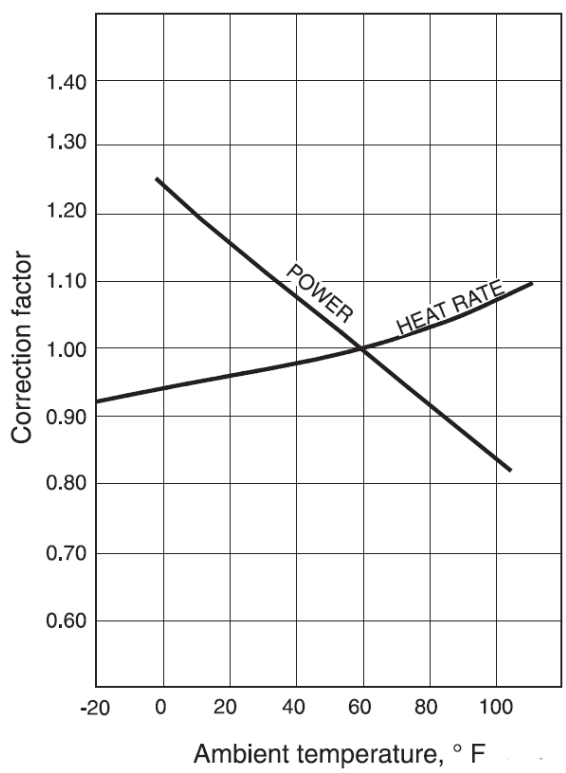


Figure G.1—Typical Gas Turbine Inlet Temperature vs. Output Power and Heat Rate

A number of different gas turbine power augmentation technologies are currently available. They can be generally classified into two categories:

1) evaporative cooling: these include wetted media and fogging;

2) heat exchanger cooling (chillers): mechanical and absorption chillers with or without thermal energy storage.

The choice between alternative cooling technologies is essentially a project decision. Dominating factors that should be taken into account in doing a study are:

1) climatic profile;

2) total life cycle analysis;

3) amount of power gained by means of inlet air cooling; this should take into account parasitic power used, the effect of increased inlet pressure drop from the cooling coils, or evaporative media;

4) environmental impact: fugitive refrigerant emissions and gas turbine exhaust emissions;

5) for power generation applications, electric daily rates have to be carefully considered.

The site annual temperature profile should be analyzed (e.g. 30 years of hourly wet and dry bulb temperature). The evaporative cooling degree-hours can be used to evaluate potential power gain from inlet fogging.

G.1.2 Heat Exchanger Cooling

Heat exchanger cooling uses a heat exchanger to cool the compressor inlet air. Ensure that water condensed on the heat exchanger coil surface is not allowed to enter the gas turbine, because this can cause FOD. A mist eliminator stage located downstream can be used to mitigate this issue. The three main kinds of heat exchanger cooling are mechanical refrigeration, absorption, and thermal storage.

In a mechanical refrigeration system, a refrigerant vapor (e.g. propane, ammonia) is compressed by means of a centrifugal, screw, or reciprocating compressor. Electric motor driven centrifugal compressors are typically used for large systems (e.g. 1000 tons). Mechanical refrigeration has a significantly higher auxiliary power consumption for the compressor driver and pumps required for the cooling water circuit. After compression, the refrigerant passes through a condenser where it gets condensed. The condensed refrigerant is then expanded in an expansion valve and provides a cooling effect. The evaporator chills cooling water that is circulated to the gas turbine inlet chilling coils in the airstream. The drawbacks of mechanical refrigeration systems are higher system complexity, power consumption, and poor part load performance compared to absorption systems. Direct expansion is also possible, but uncommon, wherein the refrigerant is used to chill air directly without a chilled water circuit. However, direct expansion can cause mechanical integrity issues to the coils due to uneven temperature distribution.

Absorption systems typically employ lithium-bromide (Li-Br) and water, with the Li-Br being the absorber and the water acting as the refrigerant. Such systems can cool the inlet air to 10 °C (50 °F). The heat for the regenerator can be provided by gas, steam, or gas turbine exhaust. Part load performance of absorption systems is relatively good, and efficiency does not drop off at part load like it does with mechanical refrigeration systems. Recently, ammonia-water absorption systems have been deployed.

Thermal storage is used when power augmentation is required only for a few hours in a day. In this approach, a cold reserve is built up during the nonpeak hours and this cold energy is utilized during the peak hours to chill the inlet air, thus increasing turbine output. As it operates in this intermittent mode, it is possible to reduce the size of the refrigeration system compared with a system that has to provide continuous cooling. The energy storage media can be ice, water, or other heat transfer liquids.

G.1.3 Evaporative Cooling

Evaporative cooling is the addition and mixing of water with the compressor inlet air (direct contact) to reduce the compressor air inlet temperature. The energy needed to evaporate the water is taken from the air in the form of sensible heat and is converted into latent heat, the energy present in the water vapor component of the air.

Two different evaporative cooling principles are employed: wetted media that is exposed to the inlet air flow and inlet fogging that sprays water mist into the gas turbine inlet system. Either system is designed to avoid liquid water carry-over into the engine inlet, but fogging systems can sometimes (unintentionally) overspray. Some common arrangements for gas turbine evaporative cooling systems are shown in Figure G.2.

Overspray occurs when the fog does not have time to evaporate or when more water is injected than is required to raise the relative humidity to 100 %. Erosion can potentially damage blade if the water droplet is too large to evaporate before entering to the axial compressor.

Fouling of the gas turbine inlet air system and axial compressor will occur with inadequate water quality.

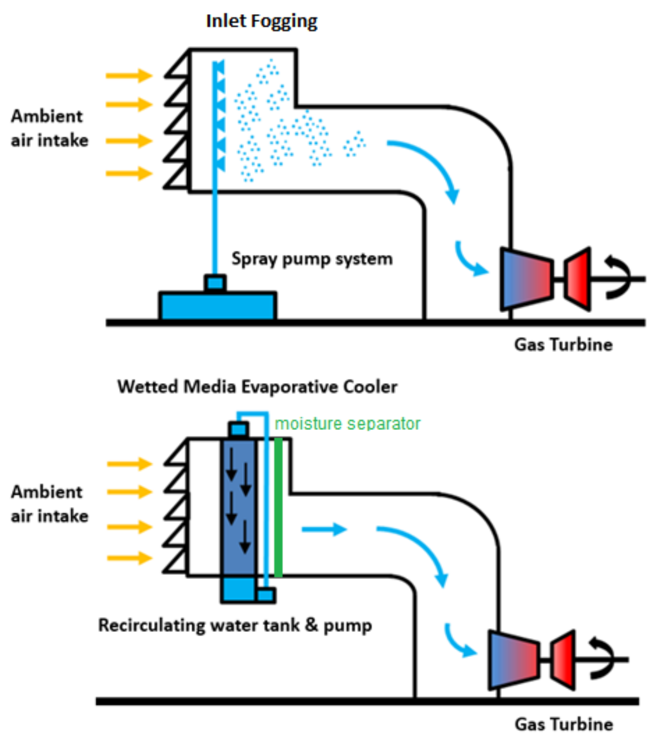


Figure G.2—Common Arrangements for Gas Turbine Inlet Evaporative Cooling

Evaporative cooling has been demonstrated to provide between 5–10 % power augmentation on hot and/or dry days. The principal difference between the evaporative cooling technologies is the quantity of water (percent air saturation), the water droplet size, and the location of the water injection ports into the gas turbine. However, the basic functional principle of all evaporative cooling systems is that they effectively reduce the gas turbine inlet air temperature from the air dry bulb temperature to the wet bulb temperature. This effective temperature difference depends on the inlet air relative humidity and temperature (as can be seen on a psychometric chart), as well as the evaporative cooler efficiency. The efficiency of evaporative devices is typically measured as the percent of the difference between dry and wet bulb temperature achieved. Specifically:

$$\text{Cooler effectiveness} = \frac{T_{1\text{DB}} - T_{2\text{DB}}}{T_{1\text{DB}} - T_{2\text{WB}}} \tag{G.1}$$

where

T_1 is inlet temperature of evaporative cooler;

T_2 is exit temperature of evaporative cooler;

DB is dry bulb;

WB is wet bulb.

A typical value for effectiveness is 85–90 %, which implies that the wet bulb temperature can never be attained. The temperature drop assuming an effectiveness of 0.9 is given in Equation (G.2):

$$dT_{\text{DB}} = 0.9\ (T_{1\text{DB}} - T_{2\text{WB}}) \tag{G.2}$$

A psychometric chart can be used to obtain the value of the wet bulb temperature. The exact power increase depends on the particular machine type, site altitude, and ambient conditions.

Wetted media evaporative coolers can have higher pressure drop than other types of inlet cooling systems. Wetted media water quality requirements are, however, less stringent than those required for inlet fogging systems.

Inlet fogging is a method of cooling where demineralized water is converted into a fog by means of special atomizing nozzles operating at pressures above 10 MPa (1450 psi) absolute. The fog, which consists of billions of particles generated at sizes of 5 to 20 microns, is injected into the inlet air where it evaporates and cools the air. A typical direct fog system consists of a series of high-pressure pumps that are mounted on a skid, control system with temperature and humidity sensors, and an array of fog nozzles installed in the inlet air duct.

Figure G.3 shows a typical inlet fogging system, 316 stainless steel impingement-type fogging nozzle. A small orifice [e.g. 0.125 mm to 0.175 mm (0.005 in. to 0.007 in.)] sprays water onto an impact pin that breaks up the jet into billions of microfine fog droplets. Other factors being equal, the rate of evaporation of the droplet essentially depends on the surface area of the water exposed to the air. With high-pressure fog, the surface area of the billions of droplets is very large, allowing rapid evaporation. Because of the geometry of a sphere, a given amount of water atomized into 10-micron (0.0004 in.) diameter droplets yields 10 times more surface area than the same amount of water atomized into 100-micron (0.004 in.) droplets. Impingement nozzles are prone to wear that increases droplet size, increasing the risk of droplet erosion on compressor blades.

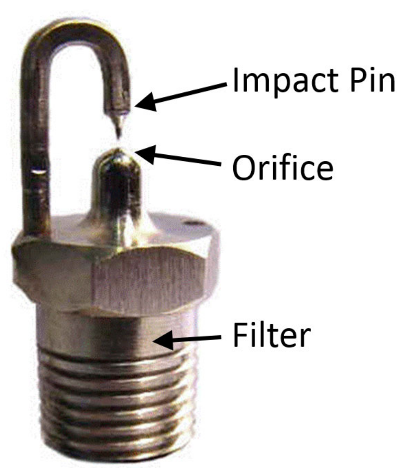


Figure G.3—Typical Fogging Nozzle

Figure G.4 shows a typical inlet fogging distribution manifold made up of tubes and fog nozzles. These manifolds induce a very low-pressure drop [e.g. 0.005 kPa (0.02 in. water)] and are all stainless steel. Considerable care and design features are incorporated to avoid flow-induced vibration. The manifold provides multiple stages of fog injection with each stage typically supplied by a dedicated high-pressure pump.

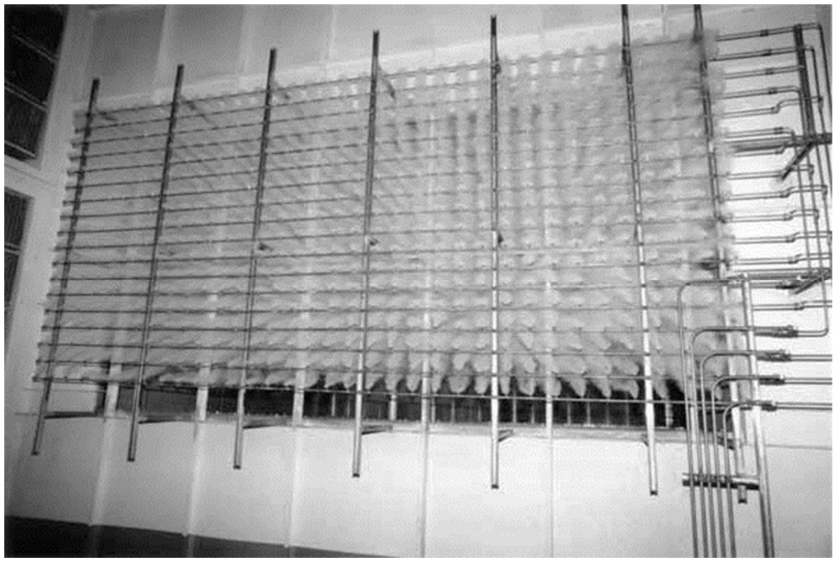


Figure G.4—Inlet Fogging Distribution Manifold

Figure G.5 shows typical inlet fogging skid. Typically, the pumps used to develop the water pressures used for gas turbine inlet air fogging systems are high-pressure, positive displacement, ceramic-plunger, stainless steel pumps (body and heads). All wetted parts are stainless steel or ceramic. Each pump is connected to a fixed number of fog nozzles, representing one discrete stage of fog injection. The control system incorporates a programmable logic controller (PLC), which is typically mounted on the pump skid. Sensors measure inlet air relative humidity, dry bulb temperature and water pressures. Programming, within the PLC, use these measured parameters to compute the inlet air wet bulb temperature and the wet bulb depression (i.e. the difference between the dry bulb and wet bulb temperature) to quantify and control the amount of evaporative cooling that is possible at the prevailing inlet conditions. The system turns on (or off) fog injection stages to match the ability of the inlet air to absorb water vapor. The programming adjusts the amount of fog injected in proportion to the inlet air mass flow.

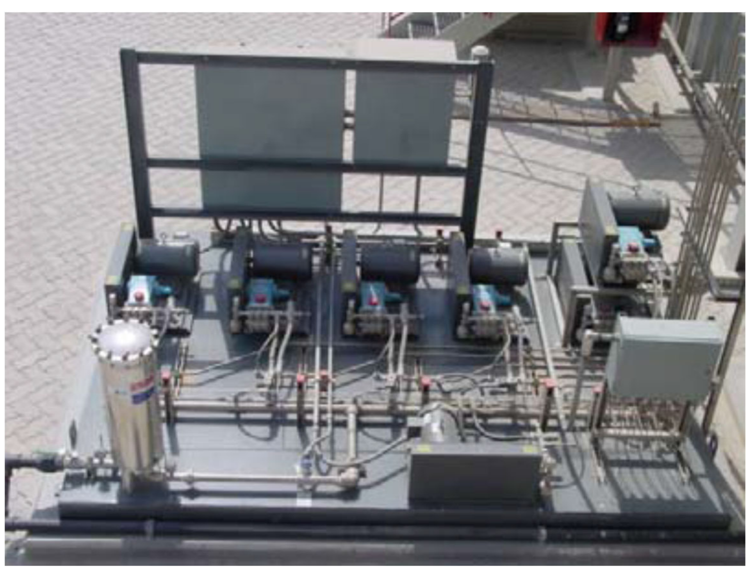


Figure G.5—Typical High-pressure Fogging Skid

For wetted media systems, careful inspection of the evaporative cooler is important in maintaining the operational reliability. Items to be considered include checks for:

1) gaps between media segments that allow air and water droplets to bypass the cooler;
2) water bypassing the media (reduces efficiency);
3) water flow rates and distribution; dry streaks on the media are indicative of poor distribution;
4) streaks on the walls of the air inlet house downstream of the drift eliminator; streaking can be caused by high air velocity, water bypassing the evaporative cooler, and/or a defective drift eliminator;
5) media quality;
6) media differential pressure;
7) water chemistry;
8) framing, drift eliminator, sump, piping, pumps, and support systems for corrosion;
9) integrity of seals, gaskets, and caulking;
10) flush the sump and piping system thoroughly annually or more frequently;
11) media and water samples for evaluation.

Table G.1 helps to identify problems and mitigations that may arise during the operation of an evaporative cooling system. However, a careful engineering analysis should be performed prior to installing any evaporative cooling system.

Table G.1—Operational Concerns with Evaporative Cooling Systems

Issues	Mitigation: Wetted Media	Mitigation: Fogging
Inlet icing	Inlet temperature automatic shut-off	Inlet temperature automatic shut-off
FOD	Not applicable	FOD screen at bell mouth Nozzle maintenance Correctly mounted manifold or nozzles
Casing distortion	Not applicable	Uniform spray pattern
Corrosion	Water quality Correct material	Water quality Correct material
Erosion	Droplet eliminator	Correctly designed atomization system
Fouling	Water quality Periodic media replacement	Water quality Periodic nozzle inspection
Air flow distortion	Uniform water distribution	Uniform spray pattern Correctly designed atomization system
Compressor surge	Inlet temperature automatic shut-off	Water quality Correctly designed atomization system Inlet temperature automatic shut-off

G.2 Gas Turbine Inlet Air Heating

G.2.1 General

Inlet air heating systems increase the temperature of the air entering the gas turbine. Most inlet air heating systems are designed to inhibit ice formation (anti-icing system) in the inlet air system. Due to the pressure drop within the inlet air system, ice can form inside the inlet system and gas turbine bell mouth, even when the inlet air temperature is above the freezing point.

The primary use of inlet air heating systems is mitigating the risk of gas turbine problems caused by ice formation:

1) gas turbine air compressor damage from ice ingestion (FOD);

2) gas turbine air compressor blade damage due to:

   a) flow disturbances exciting natural frequencies;

   b) flow anomalies creating large aerodynamic forces on blades;

3) off-design operation, including:

   a) reduced power capability;

   b) gas turbine axial compressor stall/surge; and

   c) inlet air system component failure due to ice formation and flow path blockage.

Additional uses of inlet air heating systems include:

1) controlling DLE combustion systems to satisfy air emissions parameters and associated limits across the broader ambient conditions;

2) managing unit performance considering flow constraints created by the aerodynamic design;

3) improving part load operation.

Coordinating the control of both DLE combustion systems and inlet air heating may extend the operating range at reduced load and low ambient temperatures.

Inlet air heating systems can create gas turbine problems if associated components fail and enter the flow stream or if the system arrangement introduces an unacceptable flow anomaly. Access to the inlet filter house and ducting will be restricted while the inlet air heating system is on or components are still hot. Inlet air heating systems add complexity but also enable operation or performance that is unachievable without inlet air heating.

Inlet air heating system designs vary by gas turbine model and service conditions (the entire range of inlet conditions).

G.2.2 Icing Mechanisms

Icing conditions depend on the inlet air temperature, moisture content, and the inlet system and gas turbine bell mouth pressure drop. Inlet system proximity to external moisture sources, such as tank vents or boiler stacks, can increase the inlet air moisture content above ambient air.

The two most relevant ice formation mechanisms are precipitate and condensate icing.

Precipitate icing occurs when air with free water (e.g. snow, hail, sleet, ice, rain, fog) enters the inlet air system and impinges on a surface that is below 0 °C (32 °F). This causes a buildup of ice on these surfaces. Free water impinging on a surface (e.g. filter, duct wall, splitter, bell mouth, inlet guide vanes) that is below 0 °C (32 °F) can lead to rapid ice formation.

Condensate icing occurs when humid air (without free water), at cool temperatures [e.g. < 5 °C (40 °F) and > 60 % relative humidity], is accelerated in the inlet duct, silencer passageway, or gas turbine bell mouth, causing the air temperature to depress below the dew point, resulting in free water.

G.2.3 Anti-icing Technologies

Anti-icing systems are installed upstream in the inlet air stream to promote thermal mixing and to inhibit ice formation in downstream components.

The primary technologies involved in anti-icing include:

1) inlet air heating;

2) weather protection and air inlet systems;

3) self-cleaning filters;

4) administrative controls;

5) infrared heating.

Weather protection and inlet air filtration systems can usually be designed to remove free water and limit precipitation icing.

Self-cleaning filters can provide a degree of ice protection, as ice buildup will be sensed as an increase in differential pressure and either “pulsed off” (fractured) to a degree that enables adequate air flow. Self-cleaning filters can be adversely affected by blowing snow. Snow can, depending on system design and operating conditions, accumulate to the extent that it cannot be “pulsed off.”

Administrative controls are operating instructions to avoid icing issues (e.g. restrictions on water washing and limiting gas turbine operation at low temperatures).

In self-cleaning systems, the pulses are usually able to blow the snow off the filters to protect the filter elements. For non-self-cleaning systems, a heating coil (most common), compressor air bleed (less common) or other method such as infrared heating panels heat the inlet air to a temperature above the water freezing point. Anti-icing systems are typically operational when ambient air temperature is below 5 °C (40 °F) and when relative humidity is above 65 %. At very low air temperatures (23 °F, 5 °C) the relative humidity is unlikely to be above 65 % and anti-icing would not be required. Relative humidity and inlet air temperatures sensors are necessary to automatically turn the anti-icing system on and off.

G.2.4 Inlet Air Heating Systems

G.2.4.1 General

Inlet air heating systems can be classified as follows.

1) Wet heating—A process in which moisture, as from products of combustion, is added along with the heat.

2) Dry heating—A process in which the air is heated without increasing its absolute humidity.

Inlet air heating systems can also be classified as follows.

1) Limited heating—Heating by a limited temperature increment (e.g. 2.8–5.5 °C or 5–10 °F) to reduce humidity by superheating the air.

2) Full heating—Heating of the inlet air to some fixed temperature that is above freezing (e.g. 4.5 °C or 40 °F).

Wet heating systems are also full heating, to prevent the added moisture from creating ice. Wet systems also have additional potential for corrosion.

Dry heating systems can be either limited or full heating, depending on precipitation icing risk.

G.2.4.2 Inlet Bleed Heating

Inlet bleed heating mixes a portion of hot (260–430 °C or 500–800 °F) air from the gas turbine's air compressor with the inlet air.

This type of system has been commonly used with good success, but other effects of compressor bleed should be considered (e.g. reduced power, temperature differentials, air flow anomalies, and flow-induced vibration).

Because the compressor air is much hotter and higher pressure, relative to the inlet air, getting uniform flow and temperature distribution usually requires a manifold. Incorrect design or off-design operation (i.e. high flow to gas turbine air compressor) can lead to high-cycle fatigue failure of internal gas turbine components.

Not all gas turbines have capability to direct compressor air to the air inlet system.

Inlet bleed heating cannot cause overheating issues when the gas turbine is not operating, since the system can only operate when the gas turbine is operating.

Gas turbine power output is reduced if enough compressor air is redirected to the air inlet (away from the combustors). However, this may be beneficial when operating with very low air temperatures, as the result will move the gas turbine operating point closer to the normal operating power and temperature regime, reducing combustion noise and risks associated with high-power operation.

G.2.4.3 Exhaust Gas Recirculation Heating

Exhaust gas recirculation mixes a portion of the hot (480–590 °C or 900–1100 °F) gas turbine exhaust gas with the inlet air. It is usually classified as a wet and full heating system. In contrast to inlet bleed heating, exhaust gas recirculation uses exhaust gas as the heat transfer fluid, instead of combustion air.

Exhaust gas contains significant water, carbon dioxide, and other combustion byproducts that can create ice and contribute to corrosion. Exhaust gas contains components than can foul the gas turbine air compressor, particularly liquid-fueled gas turbines. Therefore, exhaust gas is usually injected upstream of the air filter system to minimize compressor fouling.

Once the exhaust gas recirculation heating system is turned on, the heating is usually not stopped until the air temperature rises above freezing (e.g. 5 °C or 40 °F). If the air temperature drops to freezing, there is a risk that the moisture in the exhaust gases will lead to ice formation.

Exhaust gas recirculation heating cannot cause overheating issues when the gas turbine is not operating, since the system can only operate when the gas turbine is operating.

Control philosophy and flow distribution are critical. This type of system is uncommon.

G.2.4.4 Heat Exchanger Heating

Heat exchanger heating uses a heat exchanger to directly heat the compressor inlet air. In contrast to exhaust gas recirculation and inlet bleed heating, the heat transfer fluid is not in direct contact or mixed with the inlet air. This type of system is usually classified as a dry and limited heating system.

Typical heat transfer fluids include the gas turbine exhaust, building or process heat medium, steam and package lube oil. If there is a leak, the inlet air system can become contaminated with heat transfer fluid.

Heat exchanger design should consider mixing and any potential for downstream stratification.

If the control system fails to regulate heat while the gas turbine is off, or operating at low power, it is possible to overheat and damage the air filtration system (e.g. melt air filters).

Heat exchanger-based systems add complexity. The heat exchanger usually increases the inlet system pressure drop that will reduce power output, even when the system is not in use.

It is possible to use one heat exchanger and control system for inlet air cooling and heating. The operator may have to switch the system between heating and cooling modes.

G.2.4.5 Electric Heater

An electric heater system uses an electric heater to directly heat the inlet air. In contrast to the heating systems described above, electric heating does not use a heat transfer fluid. This type of system is usually classified as a dry and limited heating system.

The added electrical load should be considered/accommodated.

The electric heater is typically electrical resistor based.

If the control system fails to regulate heat while the gas turbine is off, or operating at low power, it is possible to overheat and damage the air filtration system (e.g. melt air filters).The heater usually increases the inlet system pressure drop that will reduce power output, even when the system is not in use.

G.2.4.6 Enclosure/Building Air Recirculation

Enclosure or building air recirculation heating mixes warm air from inside the equipment enclosure or building with the inlet air. The enclosure or building air may be sourced from inside the enclosure or building or from the exhaust of the building or ventilation system. This type of system is usually classified as a dry and limited heating system.

With this system, fuel and lube oil leaks inside the gas turbine enclosure can become an unintended fuel supply and increase risk of gas turbine runaway and overspeed. This technique may only be appropriate for niche applications; i.e. there is a need to maintain area classification, manage the room/enclosure temperature and control inlet air temperature, while mitigating gas turbine temperature differentials and maintaining required enclosure/building conditions.

Recirculation air is usually injected upstream of the air filter system to minimize compressor fouling.

Warm recirculation air may not be available when the building or enclosure is cold (e.g. cold start).

G.2.4.7 Inlet Air Heating Design Considerations

G.2.4.7.1 System Control

Inlet air heating control for ice mitigation may use a minimum of intake air parameters to dictate system function [e.g. if inlet air temperature is between 7 °C to 5 °C (20 °F to 40 °F) then activate inlet air heating]. Alternately, instrumentation may be installed to measure both inlet air temperature and moisture content to activate inlet air heating when the combination of temperature and moisture values (e.g. 5 °C to 5 °C or 23 °F to 40 °F and more than 70 % relative humidity).

Installations controlling inlet temperature to a set value (i.e. 5 °C or 40 °F) should be capable of adding increasing amounts of heat to the intake air. The heating source capacity has to accommodate the demand. Exhaust gas recirculation systems should use this method of control.

Inlet air heating used for performance or emissions system support will additionally include parameters based on gas turbine characteristics.

G.2.4.7.2 Flow Uniformity

The mixing hot air or exhaust gas in the inlet air system should consider aerodynamics and the risk of flow path anomalies (e.g. stratification, vortices, stagnation). If temperature, pressure or flow anomalies enter the gas turbine they can cause nozzle and blade failures (e.g. high-cycle fatigue).

Manifolds are an effective method of achieving adequate mixing. Manifolds may be located upstream of the gas turbine inlet air filters to mitigate risk of flow anomalies entering the gas turbine bell mouth. However, manifolds can be located downstream of the air filters to better mitigate condensate icing. In upstream manifolds, the energy from the heating air may be used up melting snow and ice such that the air temperature downstream remains low and condensate icing can still occur. The manifold design should consider flow-induced vibration and noise. A CFD of the inlet system, including mixing, is recommended.

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