

Instrumentation, Control, and Protective Systems for Gas Fired Heaters

API RECOMMENDED PRACTICE 556
SECOND EDITION, APRIL 2011

REAFFIRMED, APRIL 2024



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Instrumentation, Control, and Protective Systems for Gas Fired Heaters

1 Scope

1.1 Purpose

1.1.1 This recommended practice (RP) provides guidelines that specifically apply to instrument, control and protective system installations for gas fired heaters in petroleum production, refineries, petrochemical and chemical plants.

1.1.2 A gas fired general service heater defined in this practice liberates heat by the combustion of fuel gas and this heat is transferred to liquids and/or gases in tubular coils all contained within an internally insulated enclosure.

1.1.3 **Not** covered in this RP are the following:

- oil fired and combination fired heaters;
- water tube boilers which consist of single or multiple burners and are designed for utility operation or where the primary purpose is steam generation (covered by NFPA 85);
- fired steam generators used to recover heat from combustion turbines [i.e. heat recovery steam generators (HSRG)];
- oven and furnaces used for the primary purpose of incineration, oxidation, reduction or destruction of the process medium (covered by NFPA 86);
- water bath or oil bath indirect fired heaters (covered by API 12K);
- CO boilers, pyrolysis furnaces (e.g. ethylene and hydrogen reformers), and other specialty heaters.

1.1.4 This RP includes primary measuring and actuating instruments, controls, alarms, and protective systems as they apply to fired heaters. For additional subject matter review, refer to the referenced or industry standards.

1.2 General

1.2.1 Instrumentation and control applications incorporate systems and devices to satisfy equipment specific requirements. Equipment specific requirements include safety, process control, data collection, environmental reporting and other local applications.

1.2.2 Documentation including schedules, drawings, sketches, specifications and other data should be provided to install the equipment in the desired manner and for the users to maintain, inspect, test and operate the system in a safe manner.

1.2.3 The various industry codes and standards as well as laws and rules of local regulating bodies shall be followed where applicable.

1.2.4 Although it is no substitute for experience and proficiency in these fields, this document is intended to assist users with achieving such experience and proficiency. Because of the lack of uniformity in the design and requirements of the processes, the complete instrumentation and control system must be studied to determine if it will enable the unit to be started-up, operated, and shut down satisfactorily and safely.

2 References

2.1 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 Specification 6FA, *Specification for Fire Test for Valves*

API Specification 12K, *Indirect Type Oil-Field Heaters*

API Recommended Practice 534, *Heat Recovery Steam Generators*

API Recommended Practice 535, *Burners for Fired Heaters in General Refinery Services*

API Recommended Practice 551, *Process Measurement Instrumentation*

API Recommended Practice 553, *Refinery Control Valves*

API Recommended Practice 554, *Process Control Systems, Part 1 through 3*

API Recommended Practice 555, *Process Analyzers*

API Standard 560/ISO 13705, *Fired Heaters for General Refinery Services*

API Recommended Practice 573, *Inspection of Fired Boilers and Heaters*

API Standard 598, *Valve Inspection and Testing*

API Standard 607, *Fire Test for Quarter-turn Valves and Valves Equipped with Non-Metallic Seats*

ANSI/ISA 84.00.01-2004 (IEC 61511-Mod)¹, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector*

NFPA 325², *Guide to Fire Hazard Properties of Flammable Liquids, Gases, and Volatile Solids*, 1994 edition.

2.2 Other References

Certain systems are not covered in this document because of their specialized nature and limited use in petroleum refinery, hydrocarbon-processing, petrochemical, and chemical plants. When one of these systems gains general usage and installation reaches a fair degree of standardization, this document will be revised to provide additional information.

The following documents are not directly applicable to refinery heaters. These are referenced as they may be cited by regulatory bodies.

ANSI/FCI 70-2³, *Control Valve Leakage*

ASME, CSD-1⁴, *Controls and Safety Devices for Automatically Fired Boilers*

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

² National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169-7471, www.nfpa.org.

³ Fluid Components International, 1755 La Costa Meadows Drive, San Marcos, California, www.fluidcomponents.com.

EN 746-2 ⁵, *Industrial thermo processing equipment, Part 2, Safety requirements for combustion and fuel handling systems*.

ISA TR.84.00.05 ⁶, *The Application of ANSI/ISA 84.00.01-2004 (IEC 61511) for Safety Instrumented Functions (SIFs) in Burner Management Systems*

NFPA 85, *Boiler and Combustion Systems Hazards Code*

NFPA 86, *Standards for Ovens and Heaters*

3 Fired Heaters

3.1 General

API 560 contains instrumentation requirements for fired heaters and their auxiliaries.

3.2 Process Measurement

Installation of instrumentation should consider accessibility for efficient maintenance and for good operation. Flow elements, control valves, transmitters, thermowells, level gauges, and local controllers, as well as analyzer sample points, generally should be readily accessible from grade or from permanent platforms or fixed ladders. In this document, special consideration is given to the location, accessibility, and readability of the elements. Refer to API 551 for installation details.

3.2.1 Temperature

Continuous temperature measurement in fired heater applications generally uses thermocouples.

3.2.1.1 Bridgewall Temperature

The bridgewall temperature is the temperature of flue gas leaving the radiant section. Each heater and each cell of a heater should have a bridgewall temperature thermocouple located at least two feet into the firebox and just upstream of the convection section. This temperature is used for trending the approximate flue gas temperature. Highly accurate temperature measurement here is not necessary for normal refinery service heaters.

- Long/large fireboxes may require several bridgewall temperature measurements along the length of the box. These measurements may be useful in assessing the uniformity of heat distribution along the length of the firebox.
- Thermocouples in the radiant section should be installed with wells or other protective devices. The point of measurement should not have flame impingement. The thermocouples should extend past the shadow of the tube and be placed to avoid dead spots.
- A sample port next to the thermowell location is recommended to allow temperature verification.
- Thermowell materials must be suitable for the firebox temperatures and atmosphere. American Iron and Steel Institute (AISI) Types 446 and 347 stainless steel are generally acceptable materials. For some severe services, 310 stainless steel, nickel chromium iron alloy, ceramic, or ceramic-coated thermowells have been used.

⁴ ASME International, 3 Park Avenue, New York, New York 10016-5990, www.asme.org.

⁵ European Committee for Standardization, Avenue Marnix 17, B-1000, Brussels, Belgium, www.cen.eu.

⁶ International Society of Automation, 67 Alexander Drive, Research Triangle Park, North Carolina, 22709, www.isa.org.

3.2.1.2 Radiant Floor Flue Gas Temperature

A floor flue gas temperature measurement may be considered to detect operating conditions that can lead to an unstable flame condition in some radiant floor mounted, low NO_x burners with internally recirculated flue gas, especially at low flue gas oxygen levels. For further information see API 535 and discuss specific burner operating envelope concerns with the burner manufacturer. See 3.2.1.1 for additional guidance on firebox temperature measurement.

3.2.1.3 Convection Section Temperature

Flue gas temperature measurement within the convection section may be useful when multiple services are located there. Flue gas thermocouples may be located between the different services to cross-check their heat absorbed duties.

3.2.1.4 Stack Temperature

Stack temperature measurement is useful both for monitoring the heater condition (trending of typical operation) and as a component used to monitor efficiency. Stack temperature is generally grouped with other operating variables (i.e. stack oxygen, etc.) to achieve these results.

- A thermocouple in a thermowell should be installed in the stack. The portion of the breeching where the thermocouple is installed may not be representative of the fully mixed flue gas in the stack. Some areas of breeching may be in low flow zones and not representative of fully mixed flue gas in the stack.
- Multiple stack heaters should have the flue gas temperature measured in each stack.
- If a common stack is used with several heaters, each heater should have a temperature measurement in the ducting to the common stack. The common stack should still have a temperature measurement point to monitor heater efficiency and environmental performance. The common stack temperature measurement will also be useful to detect afterburning.
- On convection sections with multiple ducts to a common stack temperature measurement in each duct should be considered. This could be done with a test thermowell or on-line to assist with monitoring maldistribution.
- The stack temperature measuring device should be located near enough to the entrance of the stack so external heat losses will not have reduced the flue gas temperature. It should be placed far enough from the entrance to allow for the flow to be fully mixed and developed.
- Thermowell insertion length should be sufficient to minimize the measurement effects of the stack wall and the heat loss from the portion of the well exposed to ambient conditions. Excessive length should be avoided as stack gas induced frequency vibration of the thermowell is amplified by thermowell length.

3.2.1.5 Process Inlet and Outlet Temperatures

All heaters should have temperature measurements on the outlet and their common inlet. Usually a thermocouple with a thermowell is installed in the following areas except in many single-phase heaters with a large multiplicity of passes (i.e. many catalytic reforming heaters):

- the common inlet to the heater,
- the crossover from the convection section to the radiant section for each pass,
- outlet of the heater for each pass,
- the combined outlet from the heater.

Thermowells should be located so that they are exposed to the stream and are neither in a stagnant location nor where they might be insulated by coke deposits. If they are installed in an elbow, they should be installed so that the end of the well faces the flowing charge. This position helps keep the tip clean and ensures better response. Erosion from flow and the consequent vibration that might lead to fatigue of the well are also reduced. Thermowells should be removable for pigging or decoking, as applicable.

3.2.1.6 Tube-skin Thermocouples

Tube-skin thermocouples are used to monitor tube metal temperature.

- The number and position of tube-skin thermocouples depend on considerations such as tube coil geometry, burner orientation, and the potential to overheat due to process coking. The objective is to monitor the hottest tube locations in normal operation and locations which have a potential to overheat.
- When tube skin thermocouples are considered, the recommended minimum is two tube-skin thermocouples per pass.
- The placement of tube-skin thermocouples should be done in conjunction with a fired heater specialist experienced with the specific application.
- The thermocouple and leads must be able to withstand the severe environment within the heater. To achieve a satisfactory length of service, consider the use of a sheath material with a high temperature resistance. Fired heater skin thermocouples are severe services and replacement of these elements after each heater maintenance interval should be considered.
- Protection of the thermocouple element, through shielding, and the lead wire, through routing, from the flame as well as the corrosive atmosphere of the firebox is essential. The thermocouple element should be on the fireside of the tube. The lead wire routing should not be exposed to the flame. Flexibility must be adequate to accommodate heater tube expansion. The sheath material must resist both corrosion and embrittlement.
- The skin thermocouple assembly must be in direct contact with the tube. The protected thermocouple attachment must be welded to the tube on the hot face, towards the burners and not facing the refractory for a single-fired tube arrangement. Any gap between the tube and the thermocouple attachment will cause an erroneously high reading because the thermocouple will read the firebox temperature, not the tube temperature. Manufacturer's installation procedures together with strict adherence to approved quality control are very important to assure proper operation of the thermocouple.

3.2.1.7 Fuel Gas Temperature

Historically fuel gas headers have been at ambient conditions. However, to improve burner reliability fuel gas treatment is implemented. This treatment includes warming the fuel gas to avoid condensation and precipitation of contaminants at the burners. When orifice plate based fuel gas flow measurement and temperature compensation is used, the fuel gas temperature should be measured close to the orifice plate but not interfering with the straight run requirements of the meter run. See 3.2.3.1 for fuel gas flow.

3.2.1.8 Combustion Air Preheater Temperature

When a combustion air preheater is used, multiple temperature measurements are required in evaluating preheater performance. These should be located at the following points.

- Provide multiple thermocouples to monitor coldest metal temperature in contact with flue gas. This is typically near the flue gas outlet near the air inlet, but each design should be evaluated to determine the best location. During operation, combustion air should be bypassed around the combustion air preheater as needed to maintain the metal surface temperature above the acid dew point.

- Flue gas inlet to combustion air preheater.
- Inducted draft (ID) fan inlet (combustion air preheater flue gas discharge, sufficiently downstream of the air preheater to allow the flow to be fully mixed).
- Air temperature to the combustion air preheater (ambient reading is sufficient if the combustion air is not heated prior to the combustion air preheater).
- Forced draft air preheater outlet (upstream of air bypass duct), yet sufficiently downstream of the air preheater to allow the flow to be fully mixed.
- Combustion air to burners (downstream of air bypass duct).

3.2.2 Draft and Pressure

3.2.2.1 Draft

3.2.2.1.1 Definitions

For the purposes of this document the following definitions apply.

- When the differential pressure between the inside pressure of the heater and the atmospheric pressure at the same elevation is less than zero this is referred to as draft. When this value is positive this is referred to as positive pressure.
- A positive draft value indicates the pressure of the flue gas inside the fired heater is less than the pressure of the atmosphere outside the heater at a given elevation (i.e. the flue gas side of the fired heater is under a slight vacuum). For example, a draft of 0.1 in. H₂O (2.5 mm H₂O) of water column is equivalent to saying the pressure of the flue gas is 0.1 in. H₂O (2.5 mm H₂O) less than the air pressure at the same elevation.
- Low draft refers to the case where the pressure of the flue gas inside the heater is greater than normal. As the pressure of the flue gas approaches the pressure of the atmosphere outside the heater at a given elevation, the draft at that elevation approaches zero.
- It is possible for the pressure of the flue gas to exceed the pressure of the atmosphere outside the heater at a given elevation. When this happens, the draft at that elevation is negative. High draft refers to the case where the pressure of the flue gas inside the heater is less than normal (i.e. the amount of vacuum is greater than normal).

3.2.2.1.2 Discussion

Draft is typically measured at the following locations (see API 560 for additional information):

- near the floor using a gauge or transmitter;
- at the bridgewall using both a transmitters and a gauge;
- below the stack damper, using a gauge or transmitter.

Draft at various points on a heater are typically displayed on a panel at grade. The bridgewall is the preferred location for monitoring and control of draft inside the heater.

The pressure taps and instrumentation used for control and shutdown should be independent. To ensure measurement accuracy at the target bridgewall draft of 0.1 in. H₂O (2.5 mm H₂O) [– 0.1 in. H₂O (– 2.5 mm H₂O) differential pressure], match the transmitter cell range to the measurement range as closely as possible. A typical cell

range for flue gas draft is -3 to $+3$ in. H_2O (-75 to $+75$ mm H_2O) 30:1 turndown. A higher cell range may not have the desired sensitivity at the target draft.

Climatic conditions can cause problems with measuring draft and require operator vigilance during significant atmospheric pressure changes. The connection to the heater should be free draining into the heater to mitigate the effects of condensation. The reference leg exposed to atmosphere shall be free draining and protected from wind, insects, rain, and condensation.

NOTE 1 Draft at the bridgewall or arch is typically controlled between 0.05 and 0.2 in. H_2O (1 to 5 mm H_2O) draft.

NOTE 2 When draft at the arch is decreased, draft at the burner is decreased by approximately the same amount.

NOTE 3 For a natural draft burner with ambient pressure at the air inlet, draft at the burner/tile outlet is equal to the air side pressure drop across the burner.

NOTE 4 The air flow through the burner is proportional to the square root of the air side pressure drop.

NOTE 5 Changes in draft have a greater impact on the combustion air flow of shorter natural draft heaters than it does for taller heaters.

3.2.2.1.3 Changes in Bridgewall Draft—Examples of Impact on Stoichiometry ⁷

The examples listed below are intended to demonstrate that a step change in draft at the bridgewall may yield sub-stoichiometric conditions at the burner. Especially for the high draft case, it is possible to make a large change in draft, not reach a low draft alarm and still move the air flow to sub-stoichiometric conditions.

For each example, the following assumptions apply:

- non-premix, natural draft burners, floor fired;
- 0.01 in. H_2O per ft (0.1 mm H_2O per m) of firebox height;
- burner registers are adjusted to achieve the % stoichiometric air flow before the change in draft;
- draft is changed by moving the stack damper, burner air registers don't move during the change;
- alarm at 0 draft at the bridgewall.

EXAMPLE 1 30 ft (10 m) tall firebox, draft on target before small draft change, air flow moves to stoichiometric:

Measured Variable	Units of Measurement	Before Draft Change	After Draft Change
air flow	% stoichiometric	115	99.6
draft at the bridgewall	in. H_2O (mm H_2O)	0.1 (2.5)	0 (0)
draft at the floor	in. H_2O (mm H_2O)	0.4 (10)	0.3 (7.5)
Air flow after the change = $115 \% \times \text{SQRT}(0.3 / 0.4) = 99.6 \% \text{ stoichiometric}$			

⁷ These are merely examples for illustration purposes only. Each company should develop its own approach. They are not to be considered exclusive or exhaustive in nature. API makes no warranties, express or implied for reliance on or any omissions from the information contained in this document.

EXAMPLE 2⁷ 30 ft (10 m) tall firebox, high draft before medium draft change, air flow goes sub-stoichiometric:

Measured Variable	Units of Measurement	Before Draft Change	After Draft Change
air flow	% stoichiometric	115	89.1
draft at the bridgewall	in. H ₂ O (mm H ₂ O)	0.2 (5)	0 (0)
draft at the floor	in. H ₂ O (mm H ₂ O)	0.5 (12.5)	0.3 (7.5)
Air flow after the change = 115 % * SQRT(0.3 / 0.5) = 89.1 % stoichiometric			

EXAMPLE 3⁷ 60 ft (20 m) tall firebox, draft on target before medium draft change, air flow stays above stoichiometric:

Measured Variable	Units of Measurement	Before Draft Change	After Draft Change
air flow	% stoichiometric	115	106.4
draft at the bridgewall	in. H ₂ O (mm H ₂ O)	0.1 (2.5)	0 (0)
draft at the floor	in. H ₂ O (mm H ₂ O)	0.7 (17.5)	0.6 (15)
Air flow after the change = 115 % * SQRT(0.6 / 0.7) = 106.4 % stoichiometric			

EXAMPLE 4⁷ 60 ft (20 m) tall firebox, high draft before large draft change, air flow moves to sub-stoichiometric, low draft alarm not triggered:

Measured Variable	Units of Measurement	Before Draft Change	After Draft Change
air flow	% stoichiometric	115	91.7
draft at the bridgewall	in. H ₂ O (mm H ₂ O)	0.5 (12.5)	0.1 (2.5)
draft at the floor	in. H ₂ O (mm H ₂ O)	1.1 (27.5)	0.7 (17.5)
Air flow after the change = 115 % * SQRT(0.7 / 1.1) = 91.7 % stoichiometric			

3.2.2.2 Combustion Air Pressure

In general, combustion air pressure is measured at the following locations for heaters with air ducting (see API 560 for additional information):

- the inlet of the fan using a gauge,
- the outlet of the fan using a gauge,
- downstream of all combustion air dampers and preheater using a transmitter.

The transmitter should be located downstream of control dampers and preheater but far enough upstream of the burners that combustion air pressure at the measurement point will yield sufficiently high pressure even at turndown combustion air flow rates. Otherwise, the heater may be subject to spurious trips on low combustion air pressure. Alternatively, place the transmitter upstream of the combustion air damper with a minimum flow mechanical stop on the damper set for minimum air flow requirements.

It is generally recommended that the trip setpoint is not below the minimum span of the transmitter cell range. For example, the minimum span for a typical 3 in. H₂O (75 mm H₂O) cell range is 0.1 in. H₂O (2.5 mm H₂O). The minimum span for a typical 25 in. H₂O (625 mm H₂O) cell range is 0.5 in. H₂O (12.5 mm H₂O). A higher cell range may not have the desired sensitivity at the target trip setpoint.

The recommended location for combustion air pressure is typically at the smallest cross-sectional area of the inlet air plenum downstream of control dampers and preheater that yields the highest static pressure. Due to the size of ducts, however, the pressure at the desired air flow trip setpoint may be very low.

3.2.2.3 Flue Gas Pressure

3.2.2.3.1 Flue Gas Duct Upstream and Downstream of an Induced Draft (ID) Fan

In general, draft is measured in flue gas ducts at the following locations (see API 560 for additional information):

- inlet of the induced draft fan using a transmitter (to detect loss of ID fan),
- outlet of the induced draft fan using a gauge.

3.2.2.3.2 Combustion Air Preheat Systems

To aid in the evaluation of a combustion air preheater's performance, add pressure taps at the inlet and outlet of the air and flue gas sides of the exchanger. A differential pressure gauge is recommended for the flue gas side.

3.2.2.4 Fuel Gas Pressure

Fuel gas supply pressure should be measured upstream of the fuel gas control valves and downstream of the fuel gas preparation system. Burner pressure should be measured downstream of the fuel gas control valve and at a minimum distance from the distribution header.

Fuel gas burner pressure should be measured downstream of the fuel gas pressure control valve. The piping pressure drop from the pressure measurement point to the burner should be designed for no more than $\frac{1}{2}$ psi at maximum heat release for all anticipated fuel gas compositions. It is generally recommended that a trip setpoint is not below the minimum span of the transmitter cell range. Thus, separate transmitters to measure the low and high alarm and trip points may be required depending upon the cell range selected and the turndown capability of the transmitter.

3.2.2.5 Process Pressure

Pressure measurement of the flow passes should be located downstream of the pass control valve. It should be considered in coking and/or fouling services for troubleshooting.

For vaporizing services, especially on vacuum heaters, a process pressure measurement should accompany the temperature measurement at the combined outlet/transfer line.

3.2.3 Flow

3.2.3.1 Fuel Flow

A flow meter should be installed in the main fuel line located upstream of the fuel control valve where the pressure is relatively constant. To compensate for changes in fuel gas composition, the heat content may be measured by either analysis or inferred from fuel gas specific gravity. Analyzers are available to measure the flowing density and compensate for the temperature and pressure of the sample to determine specific gravity. The specific gravity of the gas is the ratio of the molecular weight of the mixture divided by the molecular weight of air. However, if the fuel gas composition contains varying amount of inert compounds (such as carbon dioxide or nitrogen), a Wobbe Index meter or Heat of Combustion meter is recommended for those applications where large step changes in heat content may adversely impact combustion control. See 3.2.5 for fuel gas heating value.

Since the heating value of light hydrocarbon gas mixtures, without varying amounts of inert gases, correlates closer to mass flow than volume flow it is recommended to control the mass flow of fuel gas to the heater. This minimizes the

impact to the process due to changes in fuel gas composition. If orifice plate flow meters are used to measure fuel gas mass flow, the measurement can be compensated by the flowing density of the fuel gas measured at the same temperature and pressure as the orifice plate. The orifice differential pressure multiplied by the flowing density is proportional to the square of the mass flow. Alternatively, a coriolis meter can be used to directly measure the mass flow without compensation.

3.2.3.2 Charge Flow

Flow measurement and the flow control valve(s) shall be located upstream of the heater coil.

- If the charge is divided into two or more streams through the heater, the flow in each pass should be measured in liquid services. This measurement is used for pass balancing, which in turn helps prevent coking and plugging of each pass.
- The flow can be split with manually operated valves if it tends to remain stable. If the heated fluid is partially vaporizing in the heater, the system may be unstable and may require flow controllers to hold the split constant.
- If the charge at the point of measurement is two phase flow, it will be necessary to determine the split by some method other than flow measurement since conventional flow measurement methods are not reliable in two phase service. Two phase flow cannot be measured reliably therefore the liquid and vapor phase flows should be individually controlled for each pass. Where the liquid and vapor phase flows are combined upstream of the heater, orifice plates with a differential pressure measurement on each pass can be used to assist with flow balancing (see 3.3.2).
- Pressure readings downstream of flow-splitting valves or differential pressure across the valve on each inlet may be of value to infer flow. However, it must be remembered this reading may be misleading if coking, vaporization, or tube blockages in each pass vary.
- For vapor-charged heaters, individual pass flow measurement is typically not required when symmetrical piping provides balanced flow.
- Where pass flow controllers are utilized, fail open control valves with a minimum flow mechanical stop to prohibit full closure are recommended to prevent loss of pass flow.
- For heavy coking services (crude, resid, asphalt), measurement is often specialized and may require vortex, coriolis, ultrasonic or wedge type meters.

3.2.3.3 Combustion Air Flow

Air flow in forced-draft or balanced draft heaters is often difficult to obtain. Direct or inferred methods of obtaining this measurement include the following examples.

- Flow elements located in the forced-draft duct system (for example, venturi, averaging pitot tubes, and thermal mass). This measurement may not be operable during natural draft operating mode. Limited straight run of air duct and close proximity to dampers can significantly impair accuracy and quality of air flow measurements. For applications with insufficient straight run of duct, multi-point thermal mass arrays may yield significant improvement to measurement accuracy and turndown. Averaging flow elements, flow rings, or grids can also have applicability in measuring air flow in short ducts.
- Inferred air flow by measuring differential pressure across the air preheater is unreliable due to changes in pressure and temperature. Additional consideration should be given to possible air leakage or soot blower effect if measurement is on the flue gas side.

- It is generally recommended that the trip setpoint is not below the minimum span of the transmitter cell range. For example, the minimum span for a typical 3 in. H₂O (75 mm H₂O) cell range is 0.1 in. H₂O (2.5 mm H₂O). The minimum span for a typical 25 in. H₂O (625 mm H₂O) cell range is 0.5 in. H₂O (12.5 mm H₂O). A higher cell range may not have the desired sensitivity at the target trip setpoint.

3.2.4 Flue Gas Analysis

For specific analyzer type selection and installation practices, refer to API 555 and local regulatory requirements.

3.2.4.1 General

Flue gas analyzers are used to monitor the safety and efficiency of the combustion process and to monitor and report flue gas emissions. These two functions are typically independent and have a different measurement basis (e.g. wet or dry), accuracy, response time, and maintenance requirements. Identification of the measured components and selection of the sample locations are determined by process control, process safety, or regulatory requirements. Inferential methods may also be an acceptable technique to meet these requirements, subject to regulatory approval.

The number of analyzers and sample locations are based upon many considerations including: heater type, heater control strategy, number of sections (cells) and stacks, configuration of the radiant and convection sections, damper locations, damper control, and fuel gas composition. In general, the sampling points should be located at the bridgewall or in the stack.

The location of the sampling point within the flue gas stream is important in obtaining a representative sample. For analyzers located at the bridgewall, sample probes may penetrate into the furnace 24 in. (600 mm) or more from the inside wall. Customized probe lengths are available to ensure the sample taken is representative of the majority of the flue gas flowing out of the radiant section.

For stack analyzers, air leakage (tramp air) into the fired heater upstream of the sample point will affect the concentration of the sample gas being analyzed. Sampling points should be selected to minimize this effect.

Periodic verification of analyzer performance is recommended to confirm the ability to satisfy both process control and process safety requirements. To meet these criteria, it is important to note that analyzer vendors may publish sensor response differently. While some publish the quickest response to calibration gas, others publish a more useful response to T63 or T90, i.e. 63 % or 90 % final value to a process step change. Measuring the response time to a process step change (not to calibration gas) is recommended to meet the control and safety requirements.

- Where possible, first isolate the analyzer's sensor response to a process step change. For close-coupled extractive systems, back flow the sample probe or transport tube with instrument air, nitrogen or calibration gas. Once the sensor has stabilized, return the system to normal operation. The response time to return to 63 % or 90 % final value may be compared against the vendor published response times. This technique isolates response issues associated with the analyzer. A slow response may indicate the aspirator, flame arrestors, or sample probe need cleaning or a sensor needs changing.
- When evaluating the process response time maintain a safe operating margin above combustibles breakthrough. Care is required, especially during step changes in firing rate, to prevent fuel rich combustion during analyzer testing. As an example, this may be done via a small step change reduction in the firing rate (in manual mode) while monitoring the corresponding change in excess air at the O₂ analyzer.
- Once the analyzer's sensor response has been validated, test the analyzer's process response to a step change in flue gas composition. The objective is to measure the process response, not the control system response in automatic mode. Once the process response time has been determined, a ramp rate may be configured in either the air/fuel ratio or fuel gas controller to ensure that a process step change may be detected within the overall

response time of the control loop. A slow process response may indicate that the sample probe is not sampling from the main body of the flue gas flow pattern because of improper probe length and/or sample location.

Regulatory requirements typically specify Continuous Emissions Monitoring Systems (CEMS) measurement of stack samples on a dry basis with diluent correction. Stack sample location is also specified by the regulation. CEMS measurements are typically made by utilizing an extractive analyzer sample conditioning system and must be independent from analyzers used for process control. These measurements may include a combination of NO_x, SO_x, CO and the diluents oxygen and/or CO₂.

Combining two heaters into one CEMS is not typically permitted. Verify regulatory and permit requirements before combining multiple heaters into a single CEMS analyzer.

3.2.4.2 Oxygen

One oxygen analyzer should be provided for each independent heater combustion zone. For large combustion zones one analyzer for every 30 ft (10 m) of firebox length is recommended due to non-uniformities in the firebox flue gas circulation and to facilitate balancing the burners. Oxygen measurements should be taken as near as possible to the point where combustion is completed, normally at the exit of the radiant section and before the transition to the convection section to avoid tramp air. To minimize the impact of air ingress, stack measurements for oxygen concentrations should be avoided where possible. If a stack sample is utilized, a portable oxygen analyzer should be used to prove heater integrity (no air leaks) by directly correlating the stack measurement with the oxygen concentration leaving the radiant section. Stack measurement for control is only an option if the heater is properly sealed.

Note that percent oxygen measurement is a process control variable which may be used for improving heater efficiency and maintaining safe heater operation. Percent excess combustion air should not be confused with percent oxygen measurement.

ZrO₂ sensors are “net oxygen” analyzers which are heated and utilize platinum electrode with catalytic properties and will burn any combustible compounds with oxidation potential such as hydrocarbons, CO, hydrogen, and high concentrations of sulfur dioxide. The analyzer will read the resulting oxygen after this combustion, typically a lower value.

- During combustibles breakthrough, H₂ and CO are typically the largest combustible components. The ratio of consumption for H₂ and CO to oxygen at a heated ZrO₂ sensor is approximately 2:1. As an example, a sample with 2000 ppm (0.2 %) H₂ and CO has the potential to consume 0.1 % oxygen at the sensor. Likewise, a sample with 10,000 ppm (1.0 %) H₂ and CO has the potential to consume 0.5 % oxygen at the sensor. Therefore, at low oxygen levels, it is possible for a high concentrations of H₂ and CO to mask (malfunction low) the true oxygen concentration at the sensor.
- Upon complete loss of flame, methane may be the largest component. The ratio of consumption of methane to oxygen at a heated ZrO₂ sensor is approximately 1:2. As an example, a sample with 1 % methane has the potential to consume 2 % oxygen at the sensor. Likewise, a sample with 5 % methane has the potential to consume 10 % oxygen at the sensor. Therefore, in a fuel rich environment, it is possible for a high concentration of methane to mask (malfunction low) the true oxygen concentration at the sensor.

Nitrogen backup to the instrument air system has the potential to create an oxygen analyzer malfunction high. ZrO₂ sensors make their measurement based on the difference in the partial pressure of oxygen between a reference gas and a process sample. Typically the reference gas is ambient air; however, instrument air may be used as it is readily available in most industrial facilities. When instrument air is backed up by nitrogen a change in the oxygen concentration of the reference gas will occur and false readings will be generated by the analyzer. In the case of an instrument air supply that has been changed to nitrogen, the oxygen concentration derived by the analyzer will be

higher than the actual concentration at the sampling location. If all instrument air is completely replaced by nitrogen, the analyzer will read 100 % full scale which is an obvious fault condition.

- An oxygen analyzer with heated ZrO_2 sensor is a potential ignition source during the purge cycle. Mitigation options include a purge interlock to disconnect sensor power, reverse flow of close-coupled extractive systems, or flame arrestors. See 3.4.7.1 for additional considerations.
- For both close-coupled extractive and in-situ probe systems, flame arrestors may be specified to prevent flame propagation to flue gas due to ignition of gases by the heated sensor; however, they add lag time (estimated 5 seconds to 10 seconds extractive and 1 minute for in-situ probe systems). Due to the lag time addition, flame arrestors are not recommended for process control or process safety applications where response time is critical. An alternate technique for preventing flame propagation to flue gas without adding lag time is to blowback the instrument air used for the aspirator to the flue gas through the sample probe during the purge cycle.
- For those high temperature ZrO_2 sensors that derive their sensor heating from the flue gas, it is important to note that they do not function properly until the flue gas temperature rises to the point where the ZrO_2 sensor becomes active, typically 1000 °F to 3000 °F (500 °C to 1650 °C). Thus, the impact of reduced firing rates on measurement accuracy must be considered.

Laser based technology for combustion control (oxygen trim to air or air/fuel ratio controller) is a design consideration for heater applications where a single sample point will not provide a representative sample. It has a response time of ≤ 5 seconds and can measure across a radiant section up to 100 ft (30 m). It is not an ignition source to flue gas and requires no reference air.

- Since the line-of-sight laser measurement inherently averages the concentration across the total length of the flue gas path, it will not provide indication of the source of oxygen variability in the flue gas as with the multiple point measurements. However, the “path average” measurement inherently samples a much larger cross section of the flue gas increasing the likelihood of a representative measurement. The larger sample cross-section can also improve the chances of detecting CO breakthrough from individual burners
- Laser measurement of oxygen does not require reference air for sensor performance, but purge air is typically required in order to prevent direct contact between the process flue gases and instrument optics, and the resulting damage from soiling and heat.
- Optical alignment is critical and can shift as the heater warms up. Thus, alignment should be performed at normal heater operating temperatures. Some tunable diode laser (TDL) designs have optics designed for long path lengths. The laser beam is diverged providing an increasing diameter as the path length increases; this improves alignment stability and allows alignment to be performed at start up temperature while maintaining alignment through the entire heater temperature range. This has been field proven at path lengths of up to 100 ft (30 m).
- The United States federal Environmental Protection Agency (USEPA) has not approved line-of-sight laser-based systems for use in CEMS applications, since they cannot be calibrated online with a calibration gas. Some analyzers can be validated online through “dynamic spiking”, a method referenced by USEPA (See EPA PPS-001). Some states have accepted TDL for CEMS measurements in thermal oxidizers and kilns. Typically the combustion control analyzers are not used for CEMS reporting, since the ideal combustion control measurement is in the radiant or crossover section. The oxygen and CO levels will be considerably different than in the stack (heater output). Oxygen will increase between the radiant section and the stack due to air ingress (tramp air), and CO will decrease between the radiant section and the stack due to afterburning [if the radiant section is above 1300 °F (700 °C)].

When oxygen is measured as a regulatory requirement (as a diluent), it is measured independently from analyzers used for process control. This oxygen analyzer is part of the CEMS and utilizes the CEMS sample system and reporting mechanism according to federal, state and local regulations and permit requirements.

3.2.4.3 Combustibles

Combustibles measurement may be used to detect the onset of incomplete combustion. These analyzers are typically manufactured as combination in-situ or close-coupled extractive oxygen/combustibles analyzers. When used, one combustibles analyzer should be provided for each heater cell. For large cells, due to non-uniformities in the firebox flue gas circulation and to facilitate balancing the burners, one analyzer for every 30 ft (10 m) of firebox length is recommended. Combustibles measurements should be taken as near as possible to the point where combustion should be completed, normally at the bridgewall. Combustibles should not be measured in the stack due to the potential for afterburning in the convection section.

High levels of combustibles in the flue gas may be an indication of burner tip plugging or improper burner operation or a change in fuel gas heating value.

Since catalytic bead or hot wire technology requires the presence of oxygen for combustibles detection, some sensors may report lower than actual combustible values at low oxygen concentrations. As the measured oxygen concentration approaches 0 %, some analyzers will automatically (via software) drive the combustibles measurement to full scale. Other analyzers supply the CO and/or combustibles sensor with independently sourced “auxiliary, supplemental, or dilution” air to permit combustibles measurement through the low oxygen condition. Ultimately, the user should ensure a fail-safe mechanism is provided for this hazard scenario to ensure safe heater operation.

A combustibles analyzer (catalytic bead) will typically detect CO, hydrogen, and other combustibles (excluding methane). Since the methane molecule cracks at a high temperature, detecting methane typically requires a separate sensor. Thus, the term “combustibles” can be easily misinterpreted and subsequently misapplied.

A combustibles analyzer with a heated catalytic sensor is a potential ignition source during the purge cycle. Mitigation options include a purge interlock to disconnect sensor power, reverse flow of close-coupled extractive systems, or flame arrestors. See 3.4.7.1 for additional considerations.

3.2.4.4 Carbon Monoxide (CO)

3.2.4.4.1 CO Control

When controlling a fired heater’s air/fuel ratio near the CO breakthrough point, an infrared or laser based CO specific measurement is recommended. In a properly designed system, oxygen control at levels < 1 % may be acceptable. However, the final control elements (e.g. stack dampers, automated burner registers and/or combustion air dampers) must have sufficient accuracy, turndown and repeatability to keep the heater in a safe operating region.

For process control, infrared or laser based analyzer technology with a response time ≤ 5 seconds is recommended. Although CO is detectable with a typical catalytic bead combustibles sensor, it has a response time of 20 seconds to 25 seconds to T90.

As noted in 3.2.4.2, the laser and infrared are typically “line-of-sight” measurements that inherently average across the total flue gas path. This averaged reading requires only one instrument, but it will not provide indication as to the source of CO variability in the flue gas, as with the multiple point measurements.

To minimize lag time issues and to avoid complications associated with the potential for afterburning, the CO measurement should be taken as near as possible to the point where combustion should be completed (e.g. at the top of the radiant section). However, some fired heaters with an infrared CO measurement in the stack may be successfully controlled where the flue gas temperature entering the convection section is rapidly reduced below 1200 °F (600 °C) to minimize the rate of CO afterburning. If the flue gas temperature is not rapidly reduced below 1200 °F (600 °C) upon entering the convection section, the stack measurement may become less representative of the flue gas exiting the radiant section. The rate of CO afterburning increases with higher convection section temperatures.

When using a laser based technology for CO control, methane and hydrogen will not be detected. Current laser based technology will not simultaneously detect multiple combustibles in a single laser beam. Hydrogen cannot be detected with laser technology. If desired, methane will require an independent measurement.

3.2.4.4.2 CEMS Systems

A CO specific measurement is sometimes used to satisfy a regulatory requirement. When CO is measured as a regulatory requirement it is reported on a dry basis and is independent of analytical measurements for process control. As part of the CEMS, the CO analyzer utilizes the CEMS sample system and reporting mechanism according to federal and state regulations and permit requirements. For CEMS systems, the CO analyzer is based on infrared technology and is unaffected by the presence of other flue gases such as unburned hydrocarbons, CO₂, or hydrogen. Extractive or in-situ systems can be used for CO measurement.

- Extractive systems require a sample probe, sample line, and sample conditioning system with chillers to remove moisture to provide a dry basis measurement.
- An in-situ analyzer requires access to the point of insertion. Note that if an in-situ analyzer is allowed, a satisfactory determination of the stack gas water content must be attained for dry basis correlation, typically by a grab sample and lab analysis during stack testing. For infrared based in-situ CEMS systems, moisture content may be measured directly.

3.2.4.5 Sulfur Oxides (SO_x)

Sulfur oxide analyzers, specifically sulfur dioxide measurement, may be required by regulatory agencies. With a common fuel gas header, sulfur in the fuel gas is typically measured at the fuel gas drum outlet with associated flow measurements as an alternative to installing analyzers on every heater stack.

If stack emission monitoring is required by the regulatory agency, the type of analyzer is dependent upon the agency's requirements. Monitoring and reporting SO_x on a dry basis is achieved by the use of an extractive sample conditioning system to remove the water component. Extractive type is preferred to remove as much moisture as possible, due to the solubility of low SO₂ concentrations in the water. Note that if an in-situ SO_x analyzer is allowed, a satisfactory determination of the stack gas water content must be attained for dry basis correlation, typically by a grab sample and lab analysis during stack testing. The majority of SO_x analyzers used in flue gas analysis are based upon ultraviolet or infrared technology.

3.2.4.6 Nitrogen Oxides (NO_x)

Nitrogen oxide measurement is often required by regulatory agencies. Refer to API 535 for graphs showing the relationship of NO_x to excess oxygen, firebox temperature, combustion air temperature and hydrogen content in the fuel gas.

If stack emission monitoring is required by the regulatory agency, the type of analyzer is dependent upon the requirements of the agency. Monitoring and reporting NO_x on a dry basis is achieved by the use of an extractive sample conditioning system to remove the water component. Note that if an in-situ analyzer is allowed, a satisfactory determination of the stack gas water content must be attained for dry basis correlation, typically by grab sample and lab analysis during stack testing. The majority of NO_x analyzers used in flue gas analysis are based upon chemiluminescence, ultraviolet or infrared technology.

3.2.5 Fuel Gas Heating Value

For small variations in fuel gas composition and heating value, oxygen trim control may be effective.

Where variations in fuel gas composition and heating value impact combustion control, it is recommended to compensate the fuel gas flow measurement (see 3.2.3.1). With a negligible amount of inert compounds in the fuel

gas, a change in heating value may be inferred from a change in fuel gas density (e.g. mass flow measurement or gas density analyzer).

With a varying amount of inert compounds in the fuel gas (e.g. carbon dioxide or nitrogen) and where wide variations in heating value may adversely impact combustion control, a Wobbe Index meter or Heat of Combustion meter is recommended. This measurement is generally made on the plant fuel gas system rather than at individual heaters. Calorimeters and gas chromatographs provide direct analytical measurements for determining the heating value. Gas chromatographs and calorimeters are complex and require more maintenance than densitometers; however, density measurements are not suitable for inferring the heating value of the fuel gas when significant and variable concentrations of inert gases are present in the fuel gas.

Typical fuel gas heating value analysis response times are as follows:

- fast response heating value analyzer (Residual Oxygen Measurement)—5 seconds to 90 % response;
- heating value transmitter (Thermopile)—45 seconds to 99 % response;
- gas chromatographs—3 minutes to 5 minutes.

3.2.6 Flame Monitoring

Flame monitoring in refinery heater applications with complex heaters having multiple burners and variable fuel characteristics has resulted in varied experiences with performance and reliability. There are many design and installation details to be resolved prior to considering the use of flame monitors.

Flame monitoring may be used to detect loss of flame at one or more burners. Factors to be considered when implementing a flame monitoring system include:

- burner design,
- number of burners,
- types of fuels burned,
- types of fuels burned simultaneously,
- fuel composition variations,
- heater geometry,
- quantity and type of process safety layers of protection.

3.2.6.1 Flame Monitoring Application Design

Where flame monitoring is considered, the following items may impact the location, number, and orientation of monitors.

- Ability to monitor pilot flame only, if desired, when main burners are in service.
- Ability to monitor main burner flame only when continuous duty pilots are in use. The pilot flame shall not be permitted to falsely indicate the presence of main flame.
- Number of burners, geometry of firebox and ability to discriminate between burners.

- Luminosity of flame and background radiation in firebox.
- Flame shape over the full range of fired heater load, fuel mix, and burner load.
- Potential interference from flames on other burners.
- The potential for a need to adjust sighting to achieve adequate detection and discrimination.
- Ability to distinguish between the monitored flame versus other radiation sources.
- Ability to distinguish individual flames during multiple burner operation.
- Resistance to external energy sources such as gamma radiation and X-ray radiation.
- Fail safe operation.
- Redundancy as required for reliability.

3.2.6.2 Flame Monitor Technologies

Flame ionization rod technology directly contacts the flame to monitor ions. Flame scanners detect differences between the flame and the surroundings (other burners and combustion chamber). The flame ionization rod requires period replacement while the flame scanner requires a continuous utility for purging. Intelligent video recognition of flames, although not common in the refining industry, should be considered to minimize operator visual inspections at the heater.

3.2.6.2.1 Flame Ionization Rods

The following considerations apply to flame ionization rods.

- The flame ionization rod is consumable requiring periodic replacement.
- The flame ionization rod is generally used only to detect the pilot flame.
- The highest quality flame rod may not last long if used in the main flame.

3.2.6.2.2 Flame scanners

Depending on the type of fuel used, flame scanners may be purchased as:

- infrared (IR) flame scanners,
- ultraviolet (UV) flame scanners,
- simultaneous UV/IR flame scanners.

IR detection is not recommended for fuel gas as it will generally responds to background refractory changes. Strength of signal is better from UV detectors when firing fuel gas. Combination (IR/UV) may be recommended to improve reliability.

The ability to discriminate flame within a burner may be an application issue. For example, with a staged fuel gas burner, the flame scanner may detect the presence of flames from the primary tips and not be able to detect loss of flame at the secondary gas tips.

With a large number of burners, establishing flame scanner trip voting logic can be difficult to resolve.