

Process Measurement

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Process Measurement

1 Scope

This document provides recommendations about the selection and design of process measurement systems. Further, it supplies information on their implementation and commissioning.

It covers the instrumentation life cycle including selection, design, installation, commissioning and operation. It is pertinent to those involved with instrument application including design firms, owner/operators, equipment package suppliers/integrators, construction and service personnel, as well as instrument manufacturers.

Instrument systems are often a compromise between the installed performance and maintainability. A system has to balance these requirements while ensuring that basic principles are upheld. This document assists in the understanding of these principals and making proper decisions.

This recommended practice is intended to be a source of good engineering practice. Its recommendations are practical and safe, which yield consistent and effective results.

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 Specification 6A, *Specification for Wellhead and Christmas Tree Equipment*

API Recommended Practice 556, *Instrumentation, Control, and Protective Systems for Gas Fired Heaters*

API Standard 602, *Steel Gate, Globe, and Check Valves for Sizes NPS 4 (DN 100) and Smaller for the Petroleum and Natural Gas Industries*

API Recommended Practice 2218, *Fireproofing Practices in Petroleum and Petrochemical Processing Plants*

API Recommended Practice 2350, *Overfill Protection for Storage Tanks in Petroleum Facilities*

API MPMS Chapter 1, *Vocabulary*

API MPMS Chapter 3.1B, *Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging*

API MPMS Chapter 3.3, *Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging*

API MPMS Chapter 3.6, *Measurement of Liquid Hydrocarbons by Hybrid Tank Measurement Systems*

API MPMS Chapter 14.3.1, *Concentric, Square-edged Orifice Meters—Part 1: General Equations and Uncertainty Guidelines*

API MPMS Chapter 14.3.2, *Concentric, Square-Edged Orifice Meters—Part 2: Specification and Installation Requirements, 2000*

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API MPMS Chapter 15, *Guidelines for the use of the International System of Units (SI) in the Petroleum and Allied Industries*

ASME B1.20.3 ¹, *Dryseal Pipe Threads (Inch)*

ASME B16.34, *Valves-Flanged, Threaded, and Welding End*

ASME B16.36, *Orifice Flanges*

ASME B31.1, *Power Piping*

ASME B31.3, *Process Piping*

ASME B40.1, *Pressure Gauges (with ASME B40.100)*

ASME B40.3, *Bimetallic Indicators (with ASME B40.200)*

ASME B40.4, *Filled System Indicators (with ASME B40.200)*

ASME B40.9, *Thermowells for Thermometers and Electrical Temperature Sensors (with ASME B40.200)*

ASME B40.100, *Pressure Gauges and Gauge Attachments*

ASME B40.200, *Thermometers, Direct Reading and Remote Reading*

ASME BPVC Section I, *Rules for Construction of Power Boilers*

ASME BPVC Section IID, *Properties (Customary) Materials*

ASME MFC-3M, *Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi*

ASME MFC-6M, *Measurement of Fluid Flow in Pipes Using Vortex Flowmeters*

ASME MFC-8M, *Fluid Flow in Closed Conduits: Connections for Pressure Signal Transmissions Between Primary and Secondary Devices*

ASME MFC-14M, *Measurement of Fluid Flow Using Small Bore Precision Orifice Meters*

ASME MFC-19G, *Wet Gas Flowmetering Guideline*

ASME MFC-21.2, *Measurement of Fluid Flow by Means of Thermal Dispersion Mass Flowmeters*

ASME PTC-19.2, *Pressure Measurement Instruments and Apparatus Supplement*

ASME PTC-19.3 TW, *Thermowells Performance Test Codes*

ASTM A123 ², *Standard Specification for Zinc (Hot-Dip Galvanized) Coatings on Iron and Steel Products*

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

¹ ASME International, 3 Park Avenue, New York, New York 10016-5990, www.asme.org.

² ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428, www.astm.org.



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

ASTM A733, *Standard Specification for Welded and Seamless Carbon Steel and Austenitic Stainless Steel Pipe Nipples*

ASTM A780, *Standard Practice for Repair of Damaged and Uncoated Areas of Hot-Dip Galvanized Coatings*

ASTM B68, *Standard Specification for Seamless Copper Tube, Bright Annealed*

ASTM B75, *Standard Specification for Seamless Copper Tube*

ASTM C1055, *Standard Guide for Heated System Surface Conditions that Produce Contact Burn Injuries*

ASTM D351, *Standard Classification for Natural Muscovite Block Mica and Thins Based on Visual Quality*

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ASTM D1600, *Standard Terminology for Abbreviated Terms Relating to Plastics*

ASTM DS56I, *Metals and Alloys in the Unified Numbering System (UNS) 12th Edition*

ASTM E230, *Standard Specification and Temperature-Electromotive Force (EMF) Tables for Standardized Thermocouples*

ASTM E235, *Standard Specification for Type K and Type N Mineral-Insulated, Metal-Sheathed Thermocouples for Nuclear or for Other High-Reliability Applications*

ASTM E515, *Standard Practice for Leaks Using Bubble Emission Techniques*

ASTM E608, *Standard Specification for Mineral-Insulated, Metal-Sheathed Base Metal Thermocouples*

ASTM E1137, *Standard Specification for Industrial Platinum Resistance Thermometers*

ASTM F992, *Standard Specification for Valve Label Plates*

ASTM G93, *Standard Practice for Cleaning Methods and Cleanliness Levels for Material and Equipment Used in Oxygen-Enriched Environments*

CGA 4.1 ³, *Cleaning Equipment for Oxygen Service*

DIN 43760 ⁴, *Electrical temperature sensors; reference tables for sensing resistors for resistors for resistance elements*

HPS N43.6 ⁵, *Sealed Radioactive Sources—Classification*

IEC 60068-2-11 ⁶, *Basic Environmental Testing Procedures Part 2: Tests—Test Ka: Salt Mist*

IEC 60381-1, *Analogue Signals for Process Control Systems Part 1: Direct Current Signals*

³ Compressed Gas Association, 14501 George Carter Way, Suite 103, Chantilly, VA 20151, www.cganet.com.

⁴ DIN Deutsches Institut für Normung e. V., Am DIN-Platz, Burggrafenstraße 6, 10787 Berlin, Germany, www.din.de.

⁵ Health Physics Society, 1313 Dolley Madison Boulevard - Suite 402, McLean, Virginia 22101, hps.org.

⁶ International Electrotechnical Commission, 3, rue de Varembé, P.O. Box 131, CH-1211, Geneva 20, Switzerland, www.iec.ch.

IEC 60382, *Analogue pneumatic signal for process control systems*

IEC 60529, *Degrees of Protection Provided by Enclosures (IP Code)*

IEC 60584-3, *Thermocouples Part 3: Extension and compensating cables, Tolerances and identification system*

IEC 60715, *Dimensions of Low-Voltage Switchgear and Controlgear Standardized Mounting on Rails for Mechanical Support of Electrical Devices in Switchgear and Controlgear Installations*

IEC 60721-3-4, *Classification of Environmental Conditions—Part 3: Classification of Groups of Environmental Parameters and Their Severities—Section 4: Stationary Use at Non-Weather protected Locations*

IEC 60751, *Industrial platinum resistance thermometers and platinum temperature sensors*

IEC 60770-1, *Transmitters for use in industrial-process control systems Part 1: Methods for performance evaluation*

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IEC 60947-5-4, *Low-voltage switchgear and controlgear—Part 5-4: Control circuit devices and switching elements Method of assessing the performance of low-energy contacts Special tests*

IEC 60947-5-6, *Low-Voltage switchgear and controlgear—Part 5-6: Control Circuit Devices and Switching Elements - DC Interface for Proximity Sensors and Switching Amplifiers (NAMUR)*

IEC 61298-2, *Process measurement and control devices General methods and procedures for evaluating performance Part 2: Tests under reference conditions*

IEC 61515, *Mineral Insulated Thermocouple Cables and Thermocouples*

IEC 61518, *Mating Dimensions between Differential Pressure (Type) Measuring Instruments and Flanged-On Shut-Off Devices up to 413 Bar (41,3 MPa)*

IEEE 515 ⁷, *The Testing, Design, Installation, and Maintenance of Electrical Resistance Trace Heating for Industrial Applications*

IEEE C37.90, *Standard for Relays and Relay Systems Associated with Electric Power Apparatus*

IEEE C37.90.1, *Surge Withstand Capability (SWC) Tests for Relays and Relay Systems Associated with Electric Power Apparatus*

IEEE C62.41, *IEEE Recommended Practice on Surge Voltages in Low-Voltage AC Power Circuits*

ISA 5.1 ⁸, *Instrumentation Symbols and Identification*

ISA S7.4, *Air Pressures for Pneumatic Controllers, Transmitters, and Transmission Systems*

ISA RP16.6, *Methods and Equipment for Calibration of Variable Area Meters (Rotameters)*

ISA RP42.00.01, *Nomenclature for Instrument Tube Fittings*

⁷ Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, New Jersey 08854, www.ieee.org.

⁸ The Instrumentation, Systems, and Automation Society, 67 Alexander Drive, Research Triangle Park, North Carolina, 22709, www.isa.org.

ISA RP60.4, *Documentation for Control Centers*

ISA RP60.6, *Nameplates, Labels and Tags for Control Centers*

ISA 71.04, *Environmental Conditions for Process Measurement and Control Systems: Airborne Contaminants*

ISA 84.00.01 Part 1, *Functional Safety: Safety Instrumented Systems for the Process Industry Sector—Part 1: Framework, Definitions, System, Hardware and Software Requirements*

ISO 2186⁹, *Fluid flow in closed conduits—Connections for pressure signal transmissions between primary and secondary elements*

ISO 2919, *Radiological protection—Sealed radioactive sources—General requirements and classification*

ISO 3966, *Measurement of fluid flow in closed conduits—Velocity area method using Pitot static tubes*

ISO 5167-2, *Measurement of Fluid Flow by Means of Pressure Differential Devices Inserted in Circular-Cross Section Conduits Running Full—Part 2: Orifice Plates*

ISO 7145, *Determination of Flowrate of Fluids in Closed Conduits of Circular Cross-Section—Method of Velocity Measurement at One Point of the Cross*

ISO 7194, *Measurement of fluid flow in closed conduits—Velocity-area methods of flow measurement in swirling or asymmetric flow conditions in circular ducts by means of current-meters or Pitot static tubes*

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ISO 9951, *Measurement of Gas Flow in Closed Conduits—Turbine Meters*

ISO 10790, *Measurement of Fluid Flow in Closed Conduits—Guidance to the Selection, Installation and Use of Coriolis Meters (Mass Flow, Density and Volume Flow Measurements)*

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ISO 23936-2, *Petroleum, petrochemical and natural gas industries—Non-metallic materials in contact with media related to oil and gas production—Part 2: Elastomers*

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⁹ International Organization for Standardization, 1, ch. de la Voie-Creuse, Case postale 56, CH-1211, Geneva 20, Switzerland, www.iso.org.

¹⁰ Japanese Standards Association, 1-24 Akaska 4 Minato-Ku, Tokyo, Japan 107, www.jsa.or.jp.

¹¹ Naval Sea Systems Command (Ship Systems), Commander Naval Sea Systems Command, Command Standards Executive, 1333 Isaac Hull Avenue SE Stop 5160, Washington Navy Yard, www.navsea.navy.mil.

MSS SP-83 ¹², *Class 3000 Steel Pipe Unions Socket Welding and Threaded*

MSS SP-95, *Swage Nipples and Bull Plugs*

MSS SP-99, *Instrument Valves*

MSS SP-105, *Instrument Valves for Code Applications*

NACE MR0103 ¹³, *Materials Resistant to Sulfide Stress Cracking in Corrosive Petroleum Refining Environments*

NACE MR0175/ISO 15156, *Materials For use In H₂S Containing Environments in Oil and Gas Production*

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

NEMA ICS 5, *Industrial Control and Systems Control-Circuit and Pilot Devices*

NFPA 30 ¹⁵, *Flammable and Combustible Liquids Code*

NFPA 70, *National Electrical Code*

PIP PCCIP001 ¹⁶, *instrument Piping and Tubing Systems Criteria*

PIP PCFFL000, *Orifice Plate Fabrication Details*

PIP PCIFL100, *Orifice Plate Installation Details*

PIP PCIGN100, *Instrument Pipe Support Installation Details*

PIP PCIGN200, *General Instrument Purge Details*

PIP PCILI100, *Level Transmitter Installation Details*

PIP PCSIP001, *Instrument Tubing Material Specification*

PIP PNC00002, *Abbreviated Piping Terms and Acronyms*

PIP PNSC0035, *Steam Tracing Specification*

SAE ARP4990 ¹⁷, *Turbine Flowmeter Fuel Flow Calculations*

SAE J476, *Dryseal Pipe Threads*

SAE J514, *Hydraulic Tube Fittings*

SAE J530, *Automotive Pipe Fittings*

VDI/VDE 3513 Sheet 2 ¹⁸, *Variable-Area flowmeters—Maximum permissible errors, G, of the system*

¹² Manufacturers Standardization Society of the Valve and Fittings Industry, Inc., 127 Park Street, NE, Vienna, Virginia 22180-4602, www.mss-hq.com.

¹³ NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.

¹⁴ National Electrical Manufacturers Association, 1300 North 17th Street, Suite 1752, Rosslyn, Virginia 22209, www.nema.org.

¹⁵ National Fire Protection Association, 1 Batterymarch Park, Quincy, Massachusetts 02169-7471, www.nfpa.org.

¹⁶ Process Industry Practices, 3925 West Braker Lane (R4500), Austin, Texas 78759, www.pip.org.

¹⁷ SAE International, 400 Commonwealth Drive, Warrendale, PA, 15096-0001, www.sae.org.

¹⁸ Verein Deutscher Ingenieure, Postfach 1139, Dusseldorf 1, Germany 4000, www.vdi.de.

3 General

3.1 Introduction

Instruments should meet the needs of the facility. They should be selected to provide satisfactory performance at the process conditions. They should be reliable and robust. Also, the limitations that are listed in their datasheets and instruction manuals should be understood.

Calibration procedures and repair should be taken into account. Maintainability issues include: parts availability, repair difficulty, tools and facilities, decontamination, skills necessary, and diagnostic test capabilities.

3.2 Measurement Terminology

3.2.1

compound range

Range with an elevated zero that has a negative number as its lower range value and a positive number as its upper range value. Often the zero point is placed at mid-scale. This calibration is also referred to as a zero crossing measurement.

3.2.2

elevated zero

Range where the measured variable zero value is greater than the low range value such as occurs with a wet leg differential level transmitter or a bi-directional flow meter. Occasional referred to as *suppressed range*.

3.2.3

lower range limit

Lowest value of the measured variable that a device can be adjusted to measure.

3.2.4

lower range value

Lowest value of the measured variable that a device is adjusted to measure.

3.2.5

range

Region in which a quantity is measured, received, or transmitted. The limits of this region are the lower and upper range values.

3.2.6

span

Absolute algebraic difference between the upper and lower range values. For example, a calibration range of -25 to +5 in. WC represents 30 in. WC of span.

3.2.7

suppressed zero

Range where the measured variable zero value is less than the low range value such as occurs with a dry leg differential level transmitter. Occasional referred to as *elevated range*.

3.2.8

upper range limit

Highest value of the measured variable that a device can be adjusted to measure.

3.2.9

upper range value

Highest value of the measured variable that a device is adjusted to measure.

3.2.10

turndown

Ratio of the sensor's maximum span to the sensor's minimum span. For example a pressure transmitter with a maximum span of 150 psig and a minimum span of 1.5 psig has a 100:1 turndown.

See ISA 51.1-1979, for further information on measurement terminology.

3.3 Instrument Range Selection

3.3.1 Range Requirements

Since uncertainty is dependent on the instrument span the normal operating point is recommended to lie between 50 % and 75 % of the calibrated range and not less than 25 %. The instrument calibrated range should be selected to cover the full operating window. It should be wide enough to cover alternate conditions.

It might not be practical to combine the normal and alternate operating conditions into a single instrument. It should be determined if the operating window can be relaxed or more instruments are needed. It might be acceptable to indicate the measurement during the alternate operating conditions at a lower accuracy. In some instances, it could be justifiable to accept a rough telltale measurement. An example would be using a differential flow meter at 5 % of its normal rate during a startup.

To allow for process changes the upper range limit; i.e. the maximum range, should be selected so the calibrated range can be adjusted upwards by 20 % to 50 %. For compound readings, a similar negative range limit should be provided. Because they increase the measurement uncertainty, the selection of an excessively wide range limits should be avoided.

For clarity the number of significant digits displayed should be minimized. A large measurement range may be divided by 1000 by updating the engineering units on the display. For example, an actual flow of 5,234,567 SCFH could be displayed as 5230 MSCFH. Not more than three significant digits are recommended. When meaningful, additional digits may be provided when additional precision is necessary.

Ideally, the top of scale would have no more than two significant digits with the last significant digit being a five. The possibility of confusion increases as more digits are used.

The display of suppressed zeros; e.g. 100 tons/day to 300 tons/day, should be avoided. A suppressed zero should only be used when needed to improve the resolution of analog displays and gauges. The "at rest position," which is also known as the "self-position," should be readable during startup and shutdown. The calibrated lower range value should represent the zero or sub-zero process value (e.g. 0 tons/day to 150 tons/day, 0 % to 100 % level; 0 psig to 10 psig; -1 psig to 3 psig; 0 °C to 500 °C; -50 °C to 50 °C; etc.)

To facilitate comparisons, safety transmitters should have the same range limits, calibrated range and accuracy as the corresponding process transmitters. Trip settings typically are between 10 % and 90 % of the calibrated range.

The control band should be set within the trip limits. To reduce the likelihood of spurious trips, an operating margin should be established between normal the operating setpoints and the trip setpoints. For instance, when the operational limits are within 20 % to 80 % of range, the trip limits may be within 10 % to 90 % of range. Assigning trip setpoints at 0 % or 100 % of range is not recommended. A slight error could easily mask the trip setpoint on a true trip.

However, in some applications, such as high pressure or low level, it may be advised to adjust the shutdown transmitter to a range focused on the shutdown so as to allow the trip point to stay between 10 % and 90 % of the instrument range.

3.3.2 Units of Measurement and their Presentation

Refineries in the United States mostly use a modified version of U.S. Customary Units or the IP (inch-pound) system. For instance, oil refineries commonly used the barrel (bbl) for hydrocarbons, which is 42 U.S. gallons (158 liters), to represent volume with $\text{bbl}_{60^\circ\text{F}}$ as the base unit for material balance and display purposes. For fluids whose vapor pressure is greater than atmospheric pressure at 60 °F, they are presented as a liquid at its equilibrium vapor pressure.

Other non-hydrocarbons liquids are mostly represented in gallons (gal) at flowing conditions. The flowing unit for steam is normally expressed as pounds/hour (lbs/h).

Except for steam, gas flow is represented in standard cubic feet per minute (SCFM) with H and D alternatively being used as suffixes rather than M to designate hour and day respectively. API *MPMS* and AGA equations are based upon 101.6 kPa[a] at 15.6 °C (14.73 PSIA at 60 °F) as the base condition but this pressure is not universally recognize and 101.3 kPa[a] (14.696 PSIA) is used in many non API metering and material balance calculations. There is a 0.23 % difference in these two values.

Also, SI prefixes (e.g. k as $\times 10^3$ and M as $\times 10^6$) are used intermittently. Rather, Roman numerals are common scale factors for displays with M is a thousand (10^3) and MM is a million (10^6) which is a thousand squared.

To properly abbreviate and convert these units, API *MPMS* Ch. 15-2001, along with *MPMS* Ch. 1-1994 to define the U.S. Customary Units, should be used. Both U.S. Customary and SI units are shown. Also, NIST *Handbook 44-2010*, Table C.2, is a recognized source for U.S. Customary Unit presentation and use.

The base pressure in the U.S. Customary Unit system is pounds per square inch (psi) with a “g” added to represent measurement relative to atmosphere or “a” suffix measurements taken on an absolute basis. The SI system on the other hand uses the Pascal which is most frequently presented as kPa and the SI only shows a suffix when the measurement basis is not obvious. However, it is common practice when absolute pressure is being measured that the unit is shown as kPa[a]. For higher pressures it is common to use MPa instead of carrying the additional digits needed with the kPa form of notation. In the European Union and other jurisdictions, the Bar is a legally recognized unit and is 100 kPa. Elsewhere, kg/cm^2 , which is 98.07 kPa (14.2 psig), remains in use.

When specifying ranges based upon inches of water column (WC), the measurement needs to be defined in terms of the water temperature. The density for water changes with temperature. Most instruments are calibrated to ISA RP2.1-1978, *Manometer Tables*, which is based upon water at 20 °C. Originally, differential flow meters were calibrated to water at 15.6 °C (60 °F). AGA and API metering standards now provide two values with the other being 20 °C. Transposing these two values could lead to a systematic measurement error of 0.081 % or a flow error of 0.04 %. Lastly, some standards used at metrology facilities are based upon the maximum density of water, which occurs at 3.98 °C.

To avoid water density issues for installations that use metric units it is recommended that the mBar or kPa be used rather than millimeters of water. See Table 1 for comparisons of the various based densities and measurement units. See API *MPMS* Ch. 15 for a discussion of the other measurement units that apply to process measurements.

Table 1—Conversion Factors for Inches of Water at Common Base Temperatures

Water Temp.	S.G.	PSI	1/PSI	kPa	mBar
3.98 °C	0.999973	0.0361265	27.6805	0.254344	2.54344
60 °F	0.999015	0.0360920	27.7070	0.254100	2.54100
20 °C	0.998207	0.0360627	27.7295	0.253895	2.53895
Source ISA RP2.1-1978, <i>Manometer Tables</i>					

3.3.3 Span Limits

Most transducers have an adjustable zero that is on the order of $\pm 10\%$, which is intended for minor adjustments due to calibration drift. If a large signal bias exists, a span analysis is necessary to determine if the zero can be suppressed and the range tightened to the degree needed.

For example, a weigh cell system can have a zero or tare value of 1200 Kg (2645 lbs) and a span of 300 Kg (660 lbs). This measurement can only be made if the weigh cell amplifier can be calibrated to these values. The calibration achievable depends on the zero suppression that is achievable, which might be on the order of 80 %, and the span turndown/gain could be 5:1.

Based upon these values, an amplifier with an Upper Range Limit of 1500 Kg (3306 lbs) and a Lower Range Limit of 1200 Kg (2645 lbs) just meets the requirements of this weigh system. Instead, using an amplifier with 90 % zero suppression and a 10:1 turndown together with an Upper Range Limit of 2000 Kg (4409 lbs) provides the flexibility necessary to adjust the tare value. If a 90 % zero suppression is not available, the other alternative is widening the span and losing some accuracy.

A typical differential pressure transmitter can achieve 99 % zero elevation/suppression and has a 100:1 turndown which allows sufficient adjustability for almost all level measurements. In contrast, some analog transmitters have a 5:1 turndown with a zero elevation/suppression of 80 %. This can present a calibration problem for a wet leg level transmitter that is mounted well below the lower nozzle or have an upper tap that is significantly higher than the maximum liquid level, especially if the fill fluid specific gravity is greater than the process liquid.

3.4 Instrument Selection

The instrument selection process involves the following five steps.

1) Identify the expected operating cases such as:

- a) normal flow;
- b) batch cycles;
- c) standby/recycle flow;
- d) regeneration;
- e) start-up;
- f) shutdown;
- g) upsets and emergencies.

2) Collect the following process data:

- a) fluid name;
- b) phase;
- c) flow rate;
- d) pressure;
- e) temperature;

- f) density/molecular weight;
 - g) viscosity.
- 3) Identify and collect additional information such as:
- a) vapor pressure;
 - b) dielectric;
 - c) corrosiveness;
 - d) erosion characteristics;
 - e) toxicity;
 - f) solids and contaminants;
 - g) foaming;
 - h) depositing;
 - i) solidification; e.g. coking;
 - j) reactivity;
 - k) hydraulic pulsations;
 - l) bi-directional flow;
 - m) backflow risk;
 - n) vibration.
- 4) Determine the range and accuracy needed to meet the requirements.
- 5) Select the instrument type based upon the following:
- a) device survivability and long term reliability;
 - b) mechanical integrity requirements;
 - c) materials of construction including soft goods;
 - d) process connections and isolation valves;
 - e) heating and insulation requirements;
 - f) location and accessibility;
 - g) purging and flushing needs;
 - h) electrical noise resistance;
 - i) wiring and power supply needs;

- j) electrical classifications;
- k) safety integrity level needed;
- l) certifications and markings;
- m) safety and environmental conditions;
- n) existing instruments;
- o) expertise and training requirements;
- p) calibration facilities;
- q) expendables disposal;
- r) failure modes;
- s) maintenance and sparing needs;
- t) self-diagnostic and self-documenting features;
- u) life cycle effectiveness.

3.5 Mechanical Integrity

For mechanical integrity the design pressure and temperature should be defined at the same conditions. In some cases two sets of pressure and temperature might be needed: the maximum pressure with its associated temperature, and the maximum temperature with its associated pressure.

3.6 Metallurgy and Soft Goods Selection

3.6.1 Introduction

Materials should be selected based upon the process requirements and their historical performance. In refining there are services where additional care is needed:

- Hydrogen Sulfide attack in wet services;
- chloride stress corrosion with stainless steels;
- acid attack;
- hydrogen permeation.

Materials have temperature and concentration ranges where they are applicable. They could become problematic operating outside these areas. Metallurgy and soft goods selection includes the following considerations:

- operating, maximum and minimum temperature;
- maximum pressure;
- the fluid composition, including contaminants;
- external ambient effects; e.g. exposure to small quantities of corrosives.

3.6.2 Wetted Materials

Pressure measurement elements (i.e. bellows and Bourdon tubes) are essentially thin wall springs. Corrosion changes their dimensions which affects their mechanical properties. In some situations loss of containment can occur. (See 8.3 g for suggestions to mitigate this hazard.) Suppliers and experienced corrosion engineers should be consulted to select the optimum materials. Also, see API 571 for guidance.

AISI Type 316 Stainless Steel is the most commonly used material for measuring elements and tubing. Wetted instrument parts are often upgraded to improve corrosion resistance, increase flexibility or minimize spare part requirements. AISI Type 316 Stainless Steel is often used where carbon steel would otherwise be acceptable.

Also, to eliminate painting, stainless steel is often used. Brass is acceptable for air, un-contaminated water, and inert gases, but is often avoided to retain interchangeability and avoid potential confusion. One issue with regards to stainless steel pipe fittings and flanges is that at temperatures ≤ 425 °C (800 °F), its strength is inferior to carbon steel.

The use of AISI Type 304 Stainless Steel is not recommended. It is not a standard material for the construction of instruments. Except for resistance to nitric acid, it is inferior to AISI Type 316 Stainless Steel and it has no price advantage. Conversely, AISI Type 316 Stainless Steel provides flexibility and avoids mix ups.

However, aqueous chloride environments can promote pitting and stress corrosion cracking of 300 Series Stainless Steels that are cold worked or subject to external tensile stress. Cracking usually occurs at metal temperatures above 60 °C (140 °F), but a few instances have been reported at lower temperatures. The presence of dissolved oxygen increases the propensity for cracking. In particular, bellows and instrument tubing contaminated with chlorides can be affected.

It is recommended that stainless steel not be used with chlorine, aliphatic amines and ammonium containing compounds. To avoid issues with chlorides, especially in near shore environments, N08825 is being used as a replacement for stainless steel tubing and other piping components. To ensure that enough Molybdenum (≥ 2.5 %) is provided, i316LM or 317SS should be considered for marine environments. Their hardness should be less than 80 Rb. When chloride or hydrogen sulfide concerns exist carbon steel bodies with N06022 measuring elements should be considered over stainless steel construction.

3.6.3 Material Codes

Common stainless steels (e.g. Type 316) are designed by AISI type designations regardless of their form (plate, casting, forging, etc.). Their composition and AISI type designation is defined in ASTM A240-2013.

Issues can occur when specifying materials of construction using registered trademarks and brand names. It is recommended that the UNS material code from ASTM D5561 or the plastic code from ASTM D1600 and ASTM D1418 be used with the trade name to avoid procurement complications. Additionally, some trade names refer to more than one product. For instance Teflon® is a group of fluorocarbon compounds.

Below are some common trade names and their generic identifiers:

Trade Name	UNS
Nickel	N02200
Nickel 200	N02200
Nickel 201	N02201
MONEL® Alloy 400	N04400
MONEL® Alloy R-405	N04405
MONEL® Alloy K-500	N05500
HASTELLOY® Alloy X (HX)	N06002

Trade Name	UNS
HASTELLOY C-22	N06022
HASTELLOY® Alloy C-22®	N06022
INCONEL® Alloy 600	N06600
INCONEL® Alloy 601	N06601
INCONEL® Alloy 718	N07718
CARPENTER® Alloy 20Cb-3®	N08020
INCOLOY® Alloy 800HT	N08811
INCOLOY® Alloy 800H	N08811
Alloy 825	N08825
INCOLOY 825	N08825
904L SS	N08904
HASTELLOY B	N10001
HASTELLOY C	N10002
HASTELLOY® Alloy C-276	N10276
HASTELLOY® Alloy B-2	N10665
Tantalum	R05200
STELLITE Alloy 6B (Co-Cr-W)	R30016
HAYNES® Alloy 25	R30605
Titanium Grade 2	R50400
Titanium Grade 4	R50700
Zirconium 702	R60702
17-4PH	S17400
NITRONIC® 50 (XM-19)	S20910
18-8PH	S30100
301 SS	S30100
304 SS	S30400
304L SS	S30403
304H SS	S30409
304LN SS	S30453
305 SS	S30500
316 SS	S31600
316/316L	S31600/S31603
316L SS	S31603
316Ti SS	S31635
317L SS	S31703
321 SS	S32100
321 SS	S32100
321H SS	S32109
SAF 2507™ Super Duplex	S32750
347 SS	S34700
409 SS	S40900
410 SS	S41000
430 SS	S43000
440A SS	S44002
440B SS	S44003



Trade Name	UNS
440C SS	S44004
440F SS	S44020

Trade Name	D1600/D1418
DELRIN	POM
Kalrez®	FFKM
Kel-F®	PCTFE
Kynar	PVDF
Neoprene	CR
Nitrile Rubber	NBR
PEEK	PEEK
Teflon	FEP
Teflon	PFA
Teflon	PTFE
Tefzel	ETFE
Viton®	FKM

ASTM designations such as those listed in ASME B31.3 are also an acceptable means of identifying materials. It should be understood that ASTM designations specify more than the composition of the material, but also cover their form (i.e. cast, forged, plate, bar, etc.).

3.6.4 Soft Goods

Instruments rely on o-rings and special gaskets to seal their components. Selecting an elastomer is not a straight forward process. For instance, though used extensively as an instrument o-ring, FKM is not acceptable for Amines or hot water and steam. Elastomers fail in different manners: some swell, some dissolve, and some take a compression set.

Various charts and technical reports are available from elastomer suppliers that grade the degree of compatibility. Still, different compounds or grades exist within a D1600/D1418 designation with different capabilities. Actual use with a particular fluid at the same concentration and temperature is the best guide.

An elastomer's maximum temperature, typically from 100 °C to 232 °C (212 °F to 450 °F), is a limiting factor in instrument applications. FFKM, a perfluoroelastomer, is an exception to these limitations; it is operable to 315 °C (600 °F) and some grades are resistant to steam.

Explosive Decompression (ED) can occur when an elastomer absorbs process vapor and the pressure is abruptly released. A seal can become damaged as a result and will be unable to hold pressure afterwards. EN 682, *Non-metallic Elastomers for Oil and Gas Production*, and ISO 23936, *Non-metallic Elastomers for Oil and Gas Production*, Table C.1, are the standards that cover the selection and evaluation of elastomeric seals for explosive decompression.

3.6.5 NACE

3.6.5.1 General

The NACE standards were developed to protect against catastrophic failure from sulfide stress cracking (SSC) due to H₂S. Materials in aqueous environments containing H₂S can crack under the influence of internal strains, which is usually measured by hardness. Hard materials are more susceptible to SSC than softer materials.

NACE MR0103, and NACE MR0175, are the two commonly used NACE standards used for H₂S bearing hydrocarbon services.

3.6.5.2 NACE MR0175/ISO15156

NACE MR0175, which is the original sour service standard, was written to address H₂S in low pH environments, and applies to petroleum production, drilling, gathering, and gas field processing facilities. NACE MR0175/ISO 15156-2009 dictates materials based on the severity of the sour service and pH. Materials not listed may be used, but require testing according to NACE guidelines. There is a range of concentrations and pressures for the various materials. For many materials, a simple statement that it is NACE MR0175 compliant is not adequate. AISI Type 316 Stainless Steel use is allowed for instruments and control devices, but environmental conditions, specifically the chloride concentration should be within the guidelines of Appendix A of Part 3.

The notes from Table A.6 of MR0175/ISO 15156-2009 state for “instrumentation and control devices that include but are not limited to diaphragms, pressure measuring devices, and pressure seals.” The material “should be in the solution-annealed and quenched, or annealed and stabilized heat-treatment condition; be free of cold work intended to enhance their mechanical properties; and have a maximum hardness of 22 HRC.” Further, “These materials have been used for these components without restriction on temperature, P_{H2S}, Cl⁻, or in situ pH in production environments. No limits on individual parameters are set, but some combinations of the values of these parameters might not be acceptable.”

3.6.5.3 NACE MR0103

NACE MR0103-2009 is intended to address sulfide stress cracking in the alkaline environments normally associated with downstream facilities (e.g. refineries). NACE MR0103 provides hardness limits for materials that have been found acceptable for wet sour service. Carbon and low-alloy steels should have a maximum hardness limit of 22 HRC (237 Brinell.) Additionally, it may call for heat treatment depending on the fabrication history. 300 series austenitic stainless steels are acceptable with hardness values less than 22 HRC (Rockwell C Hardness.) Higher alloyed stainless steel grades are acceptable up to 35 HRC.

Some hardenable nickel alloys are acceptable for applications requiring higher strength or a hardness up to 40 HRC. The standard does permit the use of ASTM A193 Grade B7 bolts when they are not exposed to the process, buried or encapsulated. They are satisfactory for most external flanged joints exposed to the atmosphere. Alternate bolting could be necessary for transmitter bodies mounted in instrument enclosures.

3.6.6 Hydrogen Services

Hydrogen permeation presents a difficult problem for diaphragm based devices. Hydrogen ions (i.e. protons) are formed by galvanic action between dissimilar metals or surface corrosion at the diaphragm. Due to its small size, the hydrogen ion migrates through the metal diaphragm. Once on the other side, it recombines forming a diatomic molecule that cannot re-cross the diaphragm. Instead it becomes trapped in the fill fluid. This problem manifests itself when the process pressure is dropped below the hydrogen vapor pressure causing the diaphragms to inflate. At that point the transmitter output freezes or drops to zero.

Gold plating on stainless steel diaphragm seals helps control this problem. It reduces the permeability of the diaphragm. Stainless steel is the least material affected and is the preferred base material. On the other hand, tantalum is prone to hydrogen embrittlement and should not be used. Gold plating should be considered with the following conditions:

- wet hydrogen service;
- hydrogen in corrosive environments;

- hydrogen partial pressure ≥ 621 kPa (90 PSIA);
- for a transmitter temperature ≥ 43 °C (110 °F) when any hydrogen is present.

Some extremely difficult applications could require using diaphragm seals that have thicker gold plating, but the quality of the coating is more important. Gold plating also increases the general corrosion resistance of the diaphragm.

The following recommendations apply to hydrogen services.

- a) Do not use electro-plated material (e.g. cadmium) or galvanized fittings that are electrically near the transmitter; i.e. a short conductive path.
- b) The transmitter body flanges, bypass manifolds, and pipe fittings should be stainless steel.
- c) Install the transmitter process connections facing downward so moisture does not collect on the diaphragm.
- d) The impulse line length should allow the transmitter to cool to ambient conditions.
- e) Use a sunscreen to reduce the transmitter's ambient temperature.

Hydrogen attack can be completely avoided if the transmitters use impulse tubing with liquid seals to prevent its exposure to the process vapors. See 9.3 concerning the selection and use of liquid seals.

3.6.7 Liquid Metal Embrittlement

Liquid metal embrittlement is described as a sudden reduction in rupture strength when low melting point metal enters the grain boundaries. The grain boundaries are weakened and can fail catastrophically under tensile load.

Mercury use is prohibited due to its health effects. It also has the ability to cause liquid metal embrittlement. This affects various materials containing copper such as N04400, N06600, and brass.

Cadmium plated fasteners should be completely avoided. Cadmium can lead to liquid metal embrittlement while in contact with steel or other materials. Cracks have been found at 90 % of the yield stress of steel at 204 °C (400 °F). This effect is compounded by bolt and nut threads which are crack starters. Furthermore, cadmium emits toxic fumes at 232 °C (450 °F).

Austenitic stainless steels can become contaminated by zinc at 400 °C (750 °F). Zinc coated items, such as instrument stands should not come into contact with high temperature stainless steel pipe and equipment. Galvanized structures, zinc chromate paint, and the like should not be located where molten zinc from a fire can fall on stainless steel pipes.

3.7 Signal Transmission and Communications

Historically analog technologies (i.e. voltage, current, and pneumatic) were used to transmit measurements. Analog technology continues to be used but in many applications digital communications (e.g. HART, Fieldbus, Wireless, Ethernet, etc.) have replaced these technologies.

3.7.1 Electronic Analog Signals

Electronic analog transmission technology communicates a measurement or command using dedicated wires. The signal value can be an analog value using current or voltage.

The most common analog signal is a 4-20 mA signal defined according to ANSI/ISA S50.00.01 and IEC 60381-1. The standard 4-20 mA signal has been extended by NAMUR NE-43 to provide diagnostic information. Table 2 shows the signal level interpretations for devices that conform to NAMUR NE-43 requirements.

Typically, transmitter failures are indicated by one signal level which is often user selectable. To indicate failure the signal is either less than 3.8 mA or greater than 20.5 mA.

Table 2—Output Signal, mA

Normal	4 to 20.0
Normal under range	3.8 to 4.0
Normal over range	20.0 to 20.5
Transmitter failure	3.6 to 3.8
Transmitter failure	20.5 to 22.0
Probable open field wire	0 to 3.6
Probable shorted field wire	≥22.0

A 4-20 mA signal is provided in several formats. There are two, three, and four wire configurations. There are three levels of load impedances (L, H, and U) that a device should be capable of driving. The lowest acceptable value is ISA Class L impedance, which is 300 ohms. The standard impedance of an input is 250 ohms. This leaves 50 ohms for wire and a possible low impedance local meter or test instrument. Most instruments are capable of driving 550 ohms or more. This enables the instrument to be operated with two control or monitoring devices in series.

Two wire instruments receive their power from the signal wires. Three and four wire instruments use the third and fourth wires for power. Almost all process pressure based transmitters and EMF/electrical transducers as well as several types of inline flow meters and level transmitters are “Full Isolated” ISA 2U devices according to ISA S50.00.01. They are two wire devices using a 24 VDC nominal power supply with its power, output, and electrical signal input terminals electrically isolated from each other and ground, and can drive a 550 ohm load with a 24 VDC power supply.

Four wire devices are used for measurements that require more than the nominal fifty milliwatts that are provided to two wire devices by the signal wires. These typically are ISA 4H devices; i.e. they can drive more than 800 ohms of load and have an active output. However, many of these devices are not isolated. This is often not acceptable, so further signal conditioning is needed. Further, if not taken care of by a signal conditioner, a different combination of connection points can be necessary when terminating the device onto the facility control system.

3.7.2 Pneumatic Signals

Pneumatic systems designed according to IEC 60382 or ISA S7.4 use a 20 to 100 kPa or a 3 psig to 15 psig signals respectively. Some pneumatic field instruments, particularly temperature transmitters, are difficult to calibrate since the zero and span adjustments interact.

Most control systems based entirely upon pneumatic technology are considered to be legacies. Outside of control valve actuators and their accessories, pneumatic systems based upon pneumatic signals are limited to remote valve and metering stations associated with gas pipelines, gathering systems, etc. that do not have a reliable electrical power system and use pipeline gas to operate the logic and measurement devices.

Pneumatic devices are used also in utility services where it is not effective to provide remote control and continuous surveillance is unnecessary. They are used to regulate pressure, temperature and level. Pneumatic controllers are used in the following services.

- a) The setpoint point is beyond the range of a self-contained regulator.
- b) Closer control is needed than is achievable by a regulator.
- c) The pressure drop is too small for a self-contained regulator.
- d) The materials of construction needed are unavailable with a regulator.
- e) Extra thrust is needed to ensure the valve opens after prolonged shutoff.
- f) Extreme pressure reduction is needed across a single stage.

Pneumatic level controls are integral with a measurement displacer. Local pneumatic level displacer controllers are actively used for condensate drums, knockout pots, and the like.

Large case pneumatic controllers for pressure and temperature can be mounted on a valve actuator, a pipe stand, or a local panel.

3.7.3 Digital Signals

Digital communications use the full capabilities of intelligent devices to improve accuracy and reliability, while reducing maintenance. This technology allows a convenient connection to the facility control system. Digital communications also allow multiple devices to share one wire pair, reducing wiring needs.

Digital communications facilitates measurements by providing better information. For instance the resolution of the measured variable is not limited by the transmitter's 12 bit D/A converter. This allows the measured variable to be transmitted as a floating point value in engineering units without regard to scaling. The entire measurement capability of the transmitter is utilized.

Several standards exist to enable digital communications with field instruments. IEC 61158-3-1 and IEC 61158-4-1, or H1 Foundation Fieldbus is widely used for process measurement by the refining and petrochemical industry. It is supported by the major process instrument suppliers.

The HART Protocol is also widely supported. It has evolved from being a FSK signal multiplexed on the 4-20 mA signal. It can be transmitted by a multi-drop network and wirelessly as well as other methods.

Refer to API 552 for further information on digital communications as well as the transmission of analog signals. Also see IEC 61784-1 for a more extensive description of communication protocols available for industrial communications.

3.8 Power, Grounding, and Isolation

3.8.1 Power

A variety of power sources are available depending upon the instrument. The more common power methods are:

- a) type 2U loop powered according to ISA S50.00.01;
- b) type 4H DC or AC power according to ISA S50.00.01;

- c) network power such as provided by a fieldbus;
- d) internal batteries.

Power for four wire devices can be power by either a nominal 24 VDC power supply or an AC power source. While some older designs still operate at 120 VAC or 240 VAC nominal voltage levels, most AC power devices being marketed are global products that accept voltages between 95 volts and 240 volts and 50 Hz to 60 Hz.

Most four wire devices have a 24 VDC option. For externally powered instruments, this is the preferred method of providing power. Still, it should be understood that distance limitations apply for transmitting power. In an oil refining or petrochemical facility, 180 meter or six hundred foot wire runs can be expected; this combined with a nominal 15 % voltage drop only allows loads up to 7 watts on a 18 AWG or 1.0 mm² metric wire pair in a multi-core cable. Loads above this value can require a heavier gauge wire or AC power from a UPS field panel. The latter often can be preferable since it avoids special cables. A locally mounted DC/DC power converter can also resolve voltage drop issues by boosting the voltage at the device.

3.8.2 Grounding

Grounding for instruments has two considerations. Grounding according to electric safety codes is the first consideration. The second is to ensure an accurate, low noise reading. This involves wiring at both the instrument and the control system. Almost without exception, multiple grounds can be not tolerated; this is a major source of electrical noise.

NOTE See IEC 61000-5.2, IEEE 1050, API 552, and NAMUR NE 98 for further information regarding grounding and electrical noise reduction.

3.8.3 Isolation and Surge Protection

Instruments need to be protected from stray electrical potentials and should not become a source of ground loops. They should be fully isolated according to ISA S50.00.01 requirements. A minimum dielectric strength of 500 VAC from ground and between isolated circuits is recommended. The requirements of IEEE C37.90-2005 Section 8.2 should be met, or pass IEC 61298-2-2008 Sections 6.3.2 and 6.3.3 testing with no measurable loss of resistance or a flash over.

In areas that are electrically active (e.g. near switch yards) or receive intense lightning, surge protectors should be provided with the transmitter. In these cases they should meet the requirements of IEEE C37.90.1 and Category B of IEEE C62.41 as tested according to IEC 60770-1.

3.9 Local Indicators

3.9.1 General

Local indicators are provided to assist field personnel. These indications can be a direct connected gauge or an electronic device. Changes resulting from adjustments to a local valve, etc. should be observable from the local readout. For instance, for control valve maintenance it is common practice to provide a local indicator visible from the control valve bypass.

3.9.2 Direct Connect Gauges

Pressure gauges, bi-metal thermometers, and local level indicators are often used as direct connected indicators. Typically, they require no external power but they are imprecise and have limited long term reliability.

Given their accuracy limitations, direct process indicators should not be used to calibrate transmitters. The following recommendations apply.

- a) Direct connected process pressure gauges should be provided for pressure switches and regulators.
- b) According to ASME Section I, boiler drums need a visible pressure gauge with an upper range value approximately double the safety valve setpoint ¹⁹.
- c) Rather than a local temperature indicator, a transmitter with an integral indicator for manual operation of a control valve has been found to be effective and easier to locate.
- d) Direct connected flow indicators larger than 2 in. NPS are not practical, rather electronic indicators are used. Battery powered wireless transmitters with LCD indicators can be used for local indication for services like furnace steam air decoking flow control where only local indication is necessary. (A wireless gateway is not necessary, these devices can operate independently.)
- e) Direct connected local level Indicators should be located on vessels so that they are visible from the aisles or platforms.

Other than being used as a pump run indicator, continuously online pressure gauges offer little value. Local dial indicators are prone to damage and calibration errors. Generally they do not provide a significant benefit once their total installation is evaluated. This is particularly true once startup has been completed. Many facilities consider them as disposable items and replace them only when needed. Rather, the use of blind pressure taps and test wells is recommended. However, decontamination and reuse can be an issue with temporary pressure gauges.

3.9.3 Local Electronic Indicators

Electronic indicators can be provided using the signal from the process transmitter. They can be integral with the transmitter or remotely mounted. They can operate off the 4-20mA signal from the transmitter. Typically, the drop is less than one volt so they do not burden the loop significantly. They have either an analog or digital display. Digital displays are easily configured to display engineering units. Analog meters require a custom scale often from a custom dial fabricator to obtain direct readings in engineering units.

Fieldbus transmitters can be equipped with integral indicators or these indicators can be mounted remotely and wired back to the transmitter. Independent fieldbus indicators are an option. These displays can display more than one value and perform calculations but they count as at least one device and contribute to the link loading.

3.10 Tagging and Nameplates

Instrument tagging, preferably at the time of shipment, should be provided. ASTM F992, with a Type III (Type 316 stainless steel, engraved), Grade B (metal strapping or screw), Class 3 (≥ 20 gauge or 0.5 mm), Size A (rectangular 50 mm by 20 mm or rectangular 2 in. by $7/8$ in.), Letter Size 4 ($1/8$ in. or 3 mm) nameplate is recommended. The nameplates should be attached with 18 AWG (1.0 mm²) UNS N04400 tie wire, austenitic stainless steel screws, austenitic stainless steel cable ties, or banding.

Laser engraving is recommended and is a standard technique for producing stainless steel tags.

Laminated nameplates should be fabricated from UV resistant HDPE or PMMA marine-grade plastic such as an UVA acrylic. The engraving should use medium Helvetica letters, or another sans-serif typeface, at least 4 mm high

¹⁹ At least one block valve is necessary. An additional valve may be provided near the drum as long as it is locked open. The installation has to be designed so that it can be blown out. Blowdown valves should be the multi-turn type. Also a siphon or equivalent device is needed to maintain a water seal. See ASME B31.1-2012 paragraph 122.3 and BPVC Section 1-2013 paragraph PG-60.6 for further information.

showing the instrument tag number and the service description. Nameplates with black and other dark surfaces should be avoided otherwise the contrast between the surface and the description is lost and becomes unreadable. Nameplates should be attached with waterproof, solvent resistant, high strength, temperature resistant cement, such as a two-step acrylic structural adhesive.

As a minimum, the nameplate should have the full ISA 5.1 tag number including any unit prefix. Additional information such as purchase order, service, etc. is added as desired. Also, thermowells should be stamped with the tag number of its corresponding temperature element. Abbreviations should be derived in the following order: Plant Standards, ISA RP60.6, PIP PNC00002, and ASME Y14.38.

3.11 Configuration and Configuration Management

Many measurement devices are configurable to different functions and have user set parameters. As a minimum, it is recommended that the full tag number be configured in the device, preferably at the time of shipment but no later than prior to installation. While selecting configurable devices, the user should acquire the necessary tools and software as well. The devices used to perform this configuration include:

- a) handheld configurators using either direct wiring, infrared, etc.;
- b) personal computers that use general or device specific programs and interfaces;
- c) process control system configuration interfaces;
- d) instrument interfaces; e.g. digital displays.

Procedures should be provided for configuration data retention besides the device itself.

NOTE See API 554, Part 2 for further discussion of configuration management.

3.12 Documentation

Information about the instrument is typically documented on data sheets; e.g. ISA TR20.00.01 forms or drawings. Complex instrumentation often involves more detailed documentation such as a written specification. See PIP PCEDO001, *Guidelines for Control Systems Documentation*, and ISA RP60.4, for typical project documentation requirements. Also available is ISA TR 77.70.01, *Tracking and Reporting of Instrument and Control Data*, and ISA 5.06.01, *Functional Requirements Documentation for Control Software Applications*. Central Instrument database software can be a useful tool for maintaining this information and making it widely available.

Complete instrument documentation is critical for maintenance. Regulations concerning the Management of Change (MOC) require an evaluation and documentation of the process, mechanical, and operating changes. This extends as well to the instruments and their wiring.

System integrity standards (e.g. ISA 84.00.01 Part 1) require the information that validated the system be maintained. This includes instrument data sheets and similar documentation. Compliance with these standards can be mandatory.

4 Temperature

4.1 Introduction

This section covers the installation and selection of devices for measuring temperature in refinery services. Thermowells and temperature sensors are covered as well as wiring, signal conditioning, and local indicators.

4.2 Thermowells

4.2.1 General

Thermowells are used to protect the temperature elements and to allow their replacement during operation.

Installing temperature elements in thermowells adds time lag and errors to the measurement. However, by using a spring loaded fitting so the element firmly contacts the bottom of the thermowell the measurement lags and errors are reduced. For temperatures above 290 °C (550 °F), N07718 springs should be considered.

Only in special situations such as furnace ducts are sheathed elements installed directly in the process to obtain a faster response. However, in these cases a distinct nameplate should be furnished warning that extraction could cause a process release. To prevent inadvertently removing the element, a tack weld, cotter pin, or car sealed locking fitting is recommended.

4.2.2 Thermowell Terminology

The insertion length, U , (see Figure 1) is the distance from the free end of the thermowell up to the threads, flange face, or means of attachment. The immersion length is the length of the thermowell that protrudes into the process fluid past the edge of the pipe or vessel. The lagging extension, T , is the additional section added to thermowells to extent it beyond pipe insulation. ASME B40.9 provides further information concerning about thermowell terminology.

4.2.3 Measurement Error Reduction

Temperature measurement errors include heating of the thermowell by fluid impingement, thermal radiation errors, and heat transfer between the thermowell and the surrounding fluid. Heat transfer errors occur because heat is conducted along the length of the thermowell from the process fluid at the tip to the atmosphere. The element is part of this gradient so it is not measuring the process temperature but an intermediate temperature.

The higher the temperature and lower the density and fluid velocity, the greater the error. Normally, with insulated pipe and fully turbulent flow conduction errors are small. However, lines with low densities and flow rates (e.g. furnace stacks) with standard length thermowells can have significant errors. With short thermowells on high temperature lines greater than 480 °C (900 °F), these errors can be >28 °C (50 °F). With moderate temperature liquids, less than 93 °C (200 °F), a minimum immersion length of 50 mm (2 in.) is recommended. The thermowell tip should not be inside the edge of the nozzle. The tip should always be in contact with the flow stream.

Longer thinner thermowells decrease these errors by reducing the thermal conductivity, but at the expense of strength. The element design also plays a role. Heavily insulating the nozzle, flange, and the exposed end of the thermowell is recommended for high temperature services such as furnace outlets.

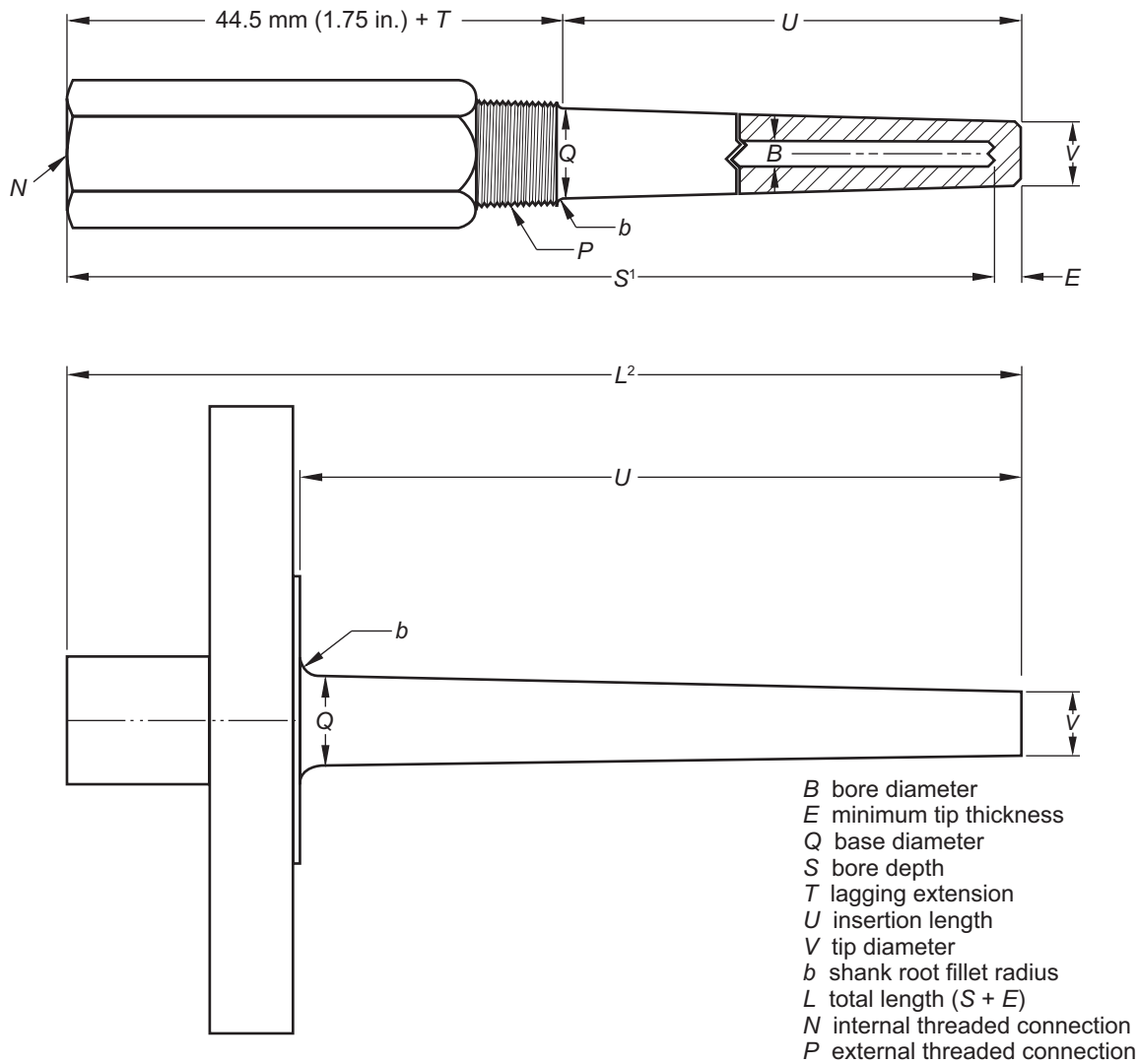
RTDs and local temperature indicators need to extend further than the thermocouple and thermistors to be fully inserted into the flowing stream. For instance a typical RTD element is 15 mm (0.6 in.) long, while a bimetal thermometer element can be 62 mm (2¹/₂ in.) long.

Further guidance on minimizing measurement errors in thermowell applications is found in ASME PTC 19.3.

4.2.4 Thermowell Strength

The optimum immersion length is a tradeoff between accuracy and response time with mechanical strength requirements. See Figure 2 for a typical thermowell installation.

Thermowells vibrate as their natural frequency is approached. This causes them to eventually fracture and fail. Thermowells have been known to fail within minutes upon being subjected to destructive vibration. On the other hand,



NOTE 1 9 in. ASME B40.9 threaded thermowell with lagging extension shown.

NOTE 2 9 in. ASME B40.9 flanged thermowell with 1½ NPS Class 300 flange shown.

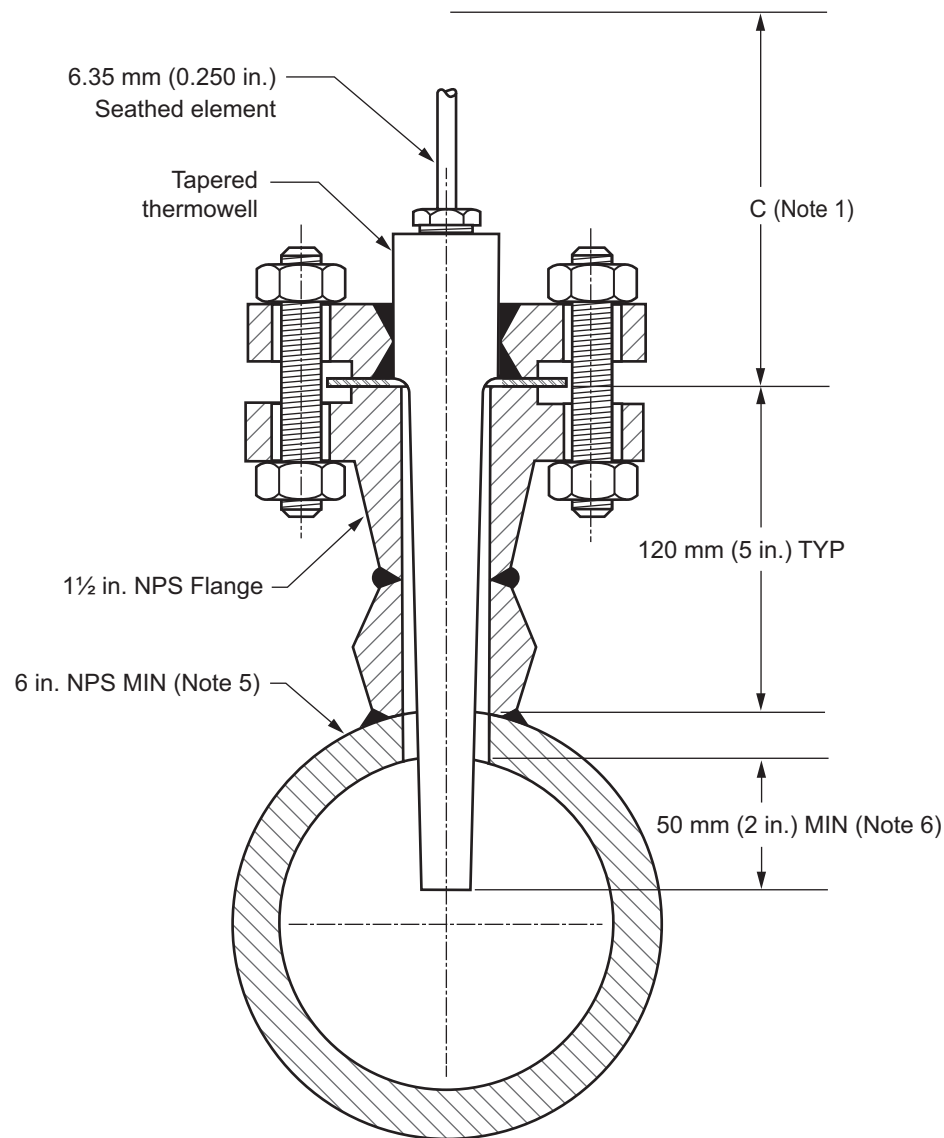
Figure 1—Thermowell Terminology

some damped thermowells have operated in the locked-in frequency zone for extended periods prior to fatigue failure. Lastly, there are cases where failure has not occurred.

Thermowells are also subjected to steady state bending loads caused by the high velocity, high density flow. Consequently, thermowells should be evaluated and documented for these failure modes.

ASME Performance Test Code PTC 19.3 TW provides information and calculation procedures for thermowells. It is a design standard for tapered, straight, and stepped-shank thermowells. However, thermowells manufactured from pipe or other materials are outside its scope. ASME PTC 19.3 TW evaluates the forces caused by external pressure and the combination of steady-drag forces and dynamic forces including oscillating-drag or in-line forces and oscillating-lift or transverse forces that result from fluid impingement.

In those instances where an adequate measurement is not possible based upon the design requirements of ASME PTC 19.3 TW, a highly damped solution might be arrived at using computational fluid dynamics. For configurations



- NOTE 1 To allow well removal, Dimension C should be 610 mm (24 in.) or the total length of the thermowell plus 76 mm (3 in.), whichever is greater.
- NOTE 2 To prevent pockets, eccentric reducers should be provided on horizontal pipe.
- NOTE 3 The inside diameter of the branch connection should ≥ 1 in.
- NOTE 4 In non-cryogenic services the thermowell preferably is installed on the top of the pipe. For cryogenic liquids to avoid trapping vapors it is recommended that the well be located in the arc from the horizontal plane to 45° below that point.
- NOTE 5 Minimum pipe size can vary with the depth of the nozzle and the length of the well plus the length of the well selected. See PIP PNF0200 concerning process pipe connections.
- NOTE 6 To allow for the element length, the minimum depth for an RTD's and Bimetal indicators should be 75 mm (3 in.).

Figure 2—Thermowell Installation

not covered by ASME PTC 19.3 TW, or for a more precise determination of the velocity limits, the use of finite element analysis (FEA) and computational fluid dynamics (CFD) can be considered. These models should be validated according to ASME V V20.

The use of support collars is not recommended and is outside the scope of ASME PTC 19.3 TW. An interference fit (i.e. a press type fit) is needed which is difficult to maintain, particularly when differential thermal growth and corrosion is considered. Further, since it is not a standard shape, a CFD analysis is needed. Rather, welded thermowells or studding outlets as shown in Figure 4 can be used to ensure that the thermowell has an adequate projection into the process.

Installing thermowells at a 45° angle increases its effective length and lowers the bending stress at the root. However, tip effects are important and the Strouhal number varies with the flow angle with the thermowell axis so there is no established method short of using a CFD evaluation for determining a velocity reduction factor. Also, a thermowell mounted in an elbow pointing into the flow is not covered by the standard.

If flow lines are closely parallel to the thermowell tip as when it is installed in an elbow pointing away from the flow, there is minimal transverse flow near the thermowell tip. This results in a bending moment reduction but ASME PTC 19.3 TW assesses these orientations conservatively, treating them no differently than a perpendicular installation and provides no credit for this configuration.

Additional precautions are recommended for thermowells subject to impact by solids such as would occur during furnace decoking or spalling.

4.2.5 Materials

The materials selected for thermowells should be suitable for the temperature and corrosion environment encountered. Typically, AISI Type 316 Stainless Steel is used with carbon steel and low chromium alloy pipe.

High strength alloys (e.g. UNS N08811) should be considered in services that have mechanical issues at high temperatures.

Thermowells in corrosive services (e.g. dilute acids, chlorides, and heavy organic acids) require corrosion resistant alloys or coatings. Also electro-polishing a thermowell according to ASTM B912 increases its resistance to coke buildup and other product adhesion. To facilitate fabrication, flanged thermowells are generally used where coatings are needed. This also allows removal and inspection.

4.2.6 Construction

Thermowells may be screw mounted as shown in Figure 3, Panel B. However in process lines, flanged thermowells such as those shown in Panel A and C are more commonly used. Van Stone wells offer the advantage that the same thermowell can be used with different class flanges. However, longer non-standard studs are needed.

Wells threaded into a flange and back welded are acceptable provided they meet the requirements of ASME B31.3-2012, Paragraphs 328.5.3 and 335.3.2; i.e. the threads are completely covered and thread compounds are removed to the maximum extent possible. However, ASME B40.9 does not accept the back welding of thermowell threads into a reducing flange so this practice is not recommended for new construction. Ring joint flanges do not provide a stiff support to resist vibration so their use is not recommended.

At a minimum, flanged thermowells with full penetration welds should be provided. According to PTC19.3 TW, thermowells that are either threaded, have un-machined welds (i.e. in the as-welded condition) or use J-groove welds exhibit inferior mechanical strength when compared to a full penetration weld. A well machined from bar stock has the best strength.

The welds should be validated by non-destructive means such as a liquid dye-penetrant test. The transition at the root should be machined smooth to a radius of 3 mm to 6 mm ($\frac{1}{8}$ in. to $\frac{1}{4}$ in.).

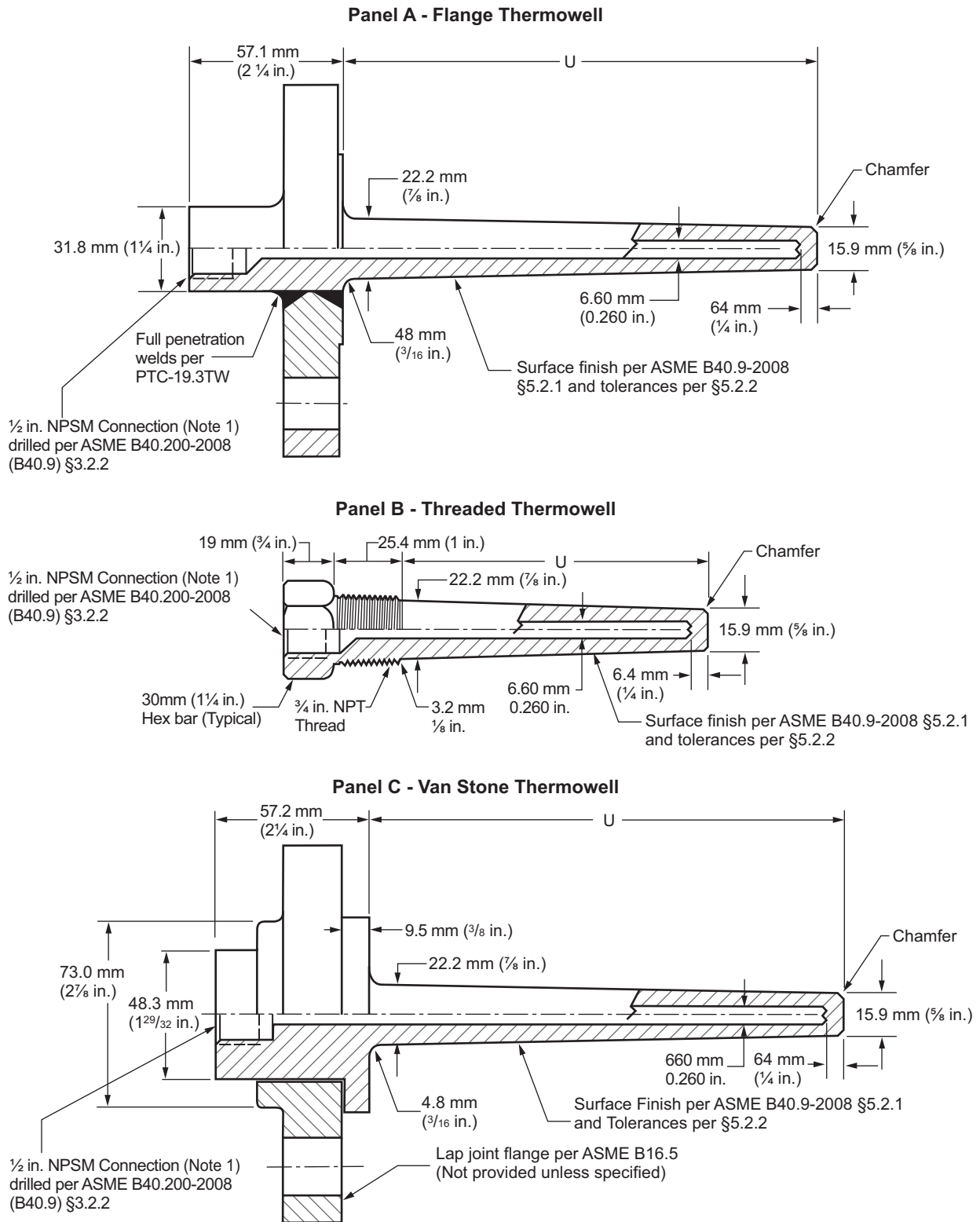


Figure 3—Standard Thermowells

In extreme situations, for maximum strength the thermowell should be fabricated as a solid piece; e.g. provided by a forged fitting or machined Van Stone thermowell. For example, Figure 4 shows a Van Stone thermowell mounted in a studding outlet to obtain near maximum insertion into the pipe. Some additional vibration resistance is possible by increasing the root and tip diameter of the well. In some applications a tapered well yields a more rugged design. However, in many applications a straight well results in a stronger design so long as the root of the straight well is increased to match that of a tapered well. ASME PTC 19.3 TW can be consulted to determine which shank style is suitable for the process conditions.

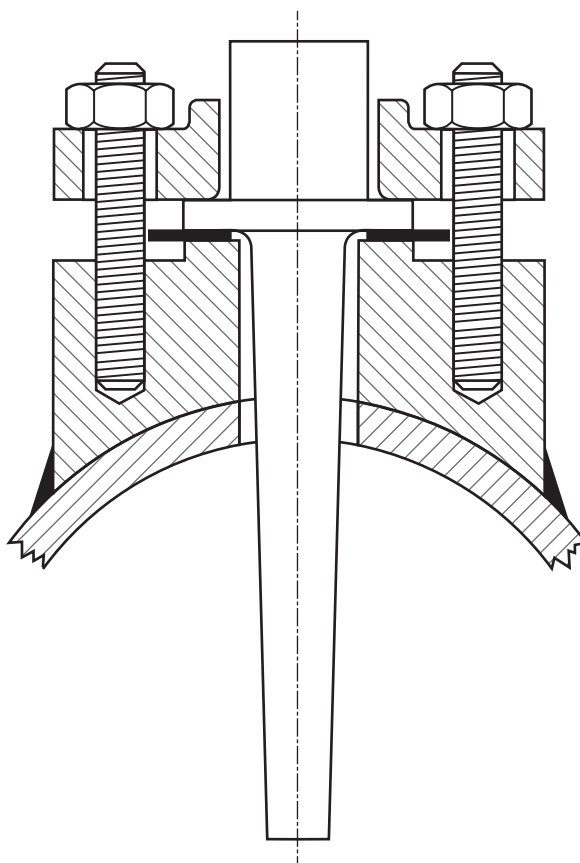


Figure 4—Van Stone Well in a Studding Outlet

4.2.7 Reactor Thermowells

When a multiple point reactor thermowell with spring loaded elements is used, a fabricated pipe thermowell is inserted into the reactor. Long reactor thermowells often need bracing along its length. It is recommended that the thermowell be supplied with the vessel to avoid alignment issues. As an alternative, sheathed thermocouple elements are routed in reactor catalyst beds through pressure tight bulk heads to the points of interest without using a thermowell.

Thermowells in alkylation, catalytic reforming, hydrocracking, and fluid catalytic cracking units require extra attention in their design. For reactors with a fluidized bed, protective sleeves are needed to protect the thermowell from abrasion.

4.2.8 High Temperature Thermowells

Temperature installations in the radiant section of fired equipment should provide an accurate measurement and still be able to withstand the furnace environment. The temperature measurement should extend past the tube shadow and should avoid dead spots. The measurement points should not be in cold gas flow paths, nor should the flame impinge on them. Also, the penetration into the firebox should allow for interference from thermal expansion between the furnace walls and the tubes. Figure 5 shows a typical ceramic thermowell and installation.

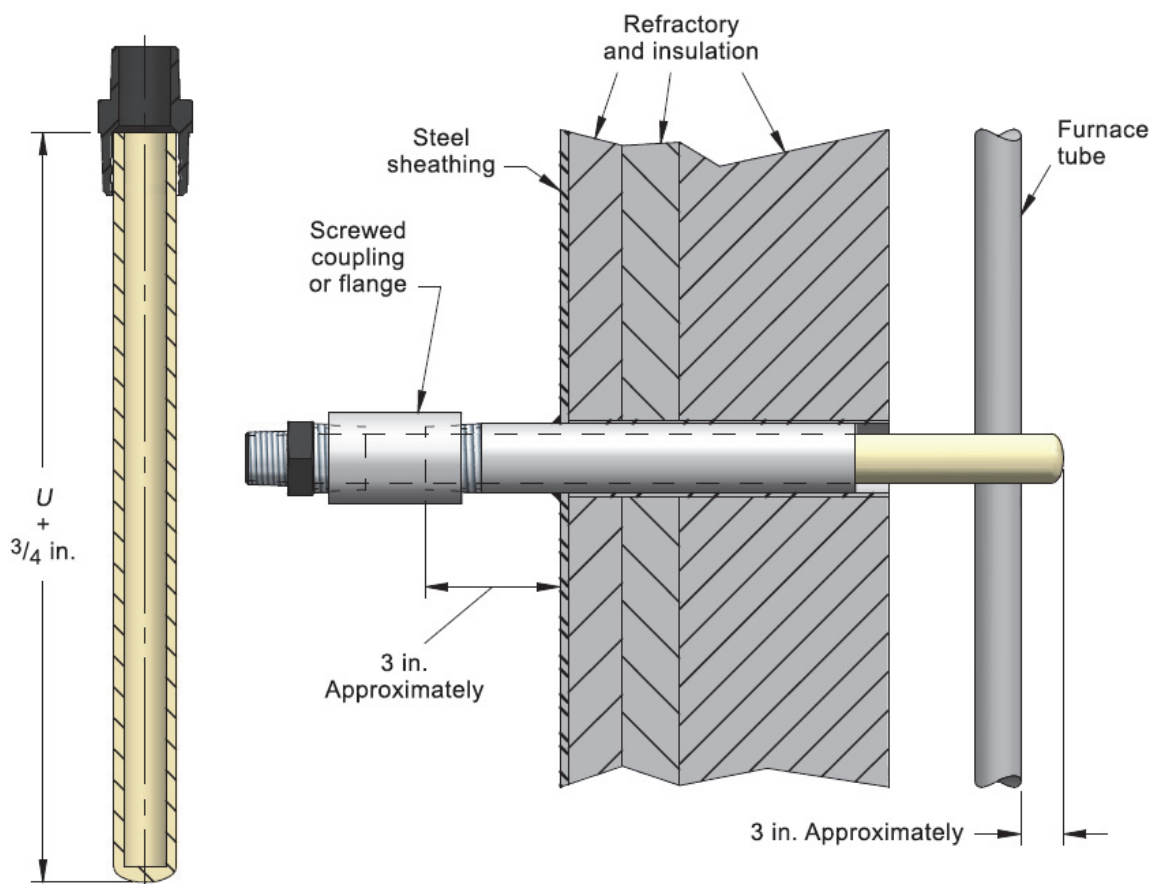


Figure 5—Ceramic Thermowell

Thermowell materials should be resistant to heat, oxidation, and the acid vapors in the firebox. N06600 AISI Type 446 and Type 347 Stainless Steel are used for heater thermowells. 12 mm ($1/2$ in.) or larger diameter bare thermocouples using nickel based sheaths are also used instead of thermowells. If they are installed horizontally supports should be considered to prevent sagging.

Ceramic thermowells perform better than metal wells with the higher temperatures that occur in refinery furnaces. For temperatures ≥ 540 °C (1000 °F) ceramics are recommended. Ceramic thermowells are mostly used in the radiant section of the furnace firebox and the lower hotter parts of the convection section. High purity, re-crystallized alumina is the preferred material. Ceramics are permeable and brittle. EN 50446-2006 has further information on the design and selection of ceramic thermowells. It is not recommended to spring load thermocouples inside ceramic thermowells. To prevent thermal shock damage the ceramic tube should be preheat to ≈ 480 °C (900 °F) prior to installing it in a hot environment.

4.3 Thermocouples

4.3.1 General

In refining, thermocouples are the most widely used temperature measuring device. The thermocouple materials most commonly used are listed in Table 3. They are applicable to -270°C to 1815°C (-454°F to 3300°F) and have acceptable accuracy and repeatability.

Type E thermocouples have the highest EMF so are the most noise resistant. They are usable in most services including cryogenics. However, Type K is frequently used in furnaces due to its extended range. Type N thermocouples are also recommended for furnace use. Type J thermocouples are mostly considered to be legacy devices because the iron thermo-element is prone to rusting.

Table 3—Standard ISA/ASTM Thermocouples Types

ISA Type	Wire Pair Colors	Alloy Combinations		ASTM E230 Recommended Range Limits	
		Positive Lead (+)	Negative Lead (-)		
B	Grey/Red	Platinum-30 % Rhodium	Platinum-6 % Rhodium	870 to 1700 °C	1600 to 3100 °F
E	Purple/Red	Nickel-10 % Chromium (Chromel)	Copper-45 % Nickel (Constantan)	-200 to 870 °C	-328 to 1600 °F
J	White/Red	Iron	Copper-45 % Nickel (Constantan)	0 to 760 °C	32 to 1400 °F
K	Yellow/Red	Nickel-10 % Chromium (Chromel)	Nickel-5 % (Aluminum, Silicon)	-200 to 1260 °C	-328 to 2300 °F
N	Orange/Red	Nickel-14 % Chromium, 1 1/2 % Silicon	Nickel-4 1/2 % Silicon-0.1 % Magnesium	0 to 1260 °C	32 to 2300 °F
R	Green/Red	Platinum-13 % Rhodium	Platinum	0 to 1480 °C	32 to 2700 °F
S	Green/Red	Platinum-10 % Rhodium	Platinum	0 to 1480 °C	32 to 2700 °F
T	Blue/Red	Copper	Copper-45 % Nickel (Constantan)	-200 to 370 °C	-328 to 700 °F
C	Green/Red	Tungsten-5 % Rhenium	Tungsten-26 % Rhenium	0 to 2315 °C	32 to 4200 °F

4.3.2 Fabrication

The most commonly used thermocouples assemblies are metal sheathed. Bare wire thermocouples are not recommended. Metal sheathed thermocouples provide an extended life and have long term accuracy. Metal sheathed thermocouples excel in applications that require long installation lengths; e.g. reactors. The sheathing provides both physical and chemical protection. They can be bent and welded onto a surface.

The thermocouple assemblies are made by densely packing the thermo-elements into the sheath with a high purity, insulating ceramic; e.g. magnesium oxide. Sheath diameters range from 1 mm to 20 mm (0.04 in. to 0.84 in.) with wire sizes from 8 to 36 AWG. Table 5 shows the recommended maximum temperature for thermocouple type by wire gauge. For ordinary temperature measurement 18 AWG wire is typically used and frequently a duplex (i.e. two elements) design is used to provide an online spare element.

ASTM E230-2012 thermocouples are provided in two accuracy grades Standard Tolerance and Special Tolerance as shown in Table 4. Also, matched thermocouple pairs are available for differential temperature measurement.

Two types of measuring junctions (see Figure 6) are in general use.

- 1) **Type A** has a grounded tip welded to the sheath for fast response and lower electrical noise.
- 2) **Type B** has an ungrounded tip and is electrically isolated from the sheath. It has a slower response.

The choice of grounded or ungrounded thermocouples is dictated by the application. For Type A thermocouples, a suitable ground path is necessary through the thermowell. Regardless, the signal ground should only be at one point.

Sheathed thermocouples should be provided according to the requirements of ASTM E608. IEC 61515 also covers fabrication and testing of thermocouples. Standard thermocouple tables are listed in ASTM E230.

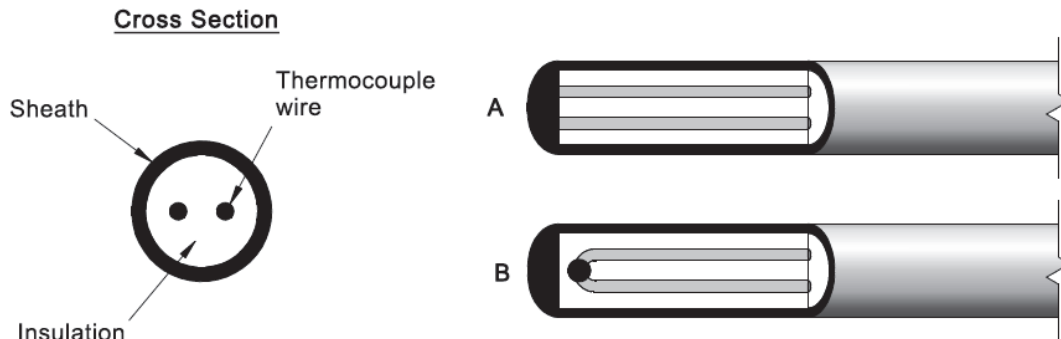


Figure 6—Metal-sheathed Thermocouple Types

Table 4—Thermocouple Interchangeability Tolerance

Type	Standard Tolerance	Special Tolerance
B	$\pm 0.5\%$	$\pm 0.25\%$
E	$\pm 1.7\text{ }^{\circ}\text{C}$ ($3.1\text{ }^{\circ}\text{F}$) or $\pm 0.5\%$	$\pm 1\text{ }^{\circ}\text{C}$ ($1.8\text{ }^{\circ}\text{F}$) or $\pm 0.4\%$
J	$\pm 2.2\text{ }^{\circ}\text{C}$ ($4\text{ }^{\circ}\text{F}$) or $\pm 0.75\%$	$\pm 1.1\text{ }^{\circ}\text{C}$ ($2\text{ }^{\circ}\text{F}$) or $\pm 0.4\%$
K	$\pm 2.2\text{ }^{\circ}\text{C}$ ($4\text{ }^{\circ}\text{F}$) or $\pm 0.75\%$	$\pm 1.1\text{ }^{\circ}\text{C}$ ($2\text{ }^{\circ}\text{F}$) or $\pm 0.4\%$
N	$\pm 2.2\text{ }^{\circ}\text{C}$ ($4\text{ }^{\circ}\text{F}$) or $\pm 0.75\%$	$\pm 1.1\text{ }^{\circ}\text{C}$ ($2\text{ }^{\circ}\text{F}$) or $\pm 0.4\%$
R	$\pm 1.5\text{ }^{\circ}\text{C}$ ($2.7\text{ }^{\circ}\text{F}$) or $\pm 0.25\%$	$\pm 0.6\text{ }^{\circ}\text{C}$ ($1.08\text{ }^{\circ}\text{F}$) or $\pm 0.1\%$
S	$\pm 1.5\text{ }^{\circ}\text{C}$ ($2.7\text{ }^{\circ}\text{F}$) or $\pm 0.25\%$	$\pm 0.6\text{ }^{\circ}\text{C}$ ($1.08\text{ }^{\circ}\text{F}$) or $\pm 0.1\%$
T	$\pm 1\text{ }^{\circ}\text{C}$ ($1.8\text{ }^{\circ}\text{F}$) or $\pm 0.75\%$	$\pm 0.5\text{ }^{\circ}\text{C}$ ($0.9\text{ }^{\circ}\text{F}$) or $\pm 0.4\%$
C	$\pm 4.4\text{ }^{\circ}\text{C}$ ($7.9\text{ }^{\circ}\text{F}$) or $\pm 1.0\%$	

Table 5—Recommended Limit for Single Element Sheathed Thermocouples

Sheath OD		Wire AWG	Thermocouple Type $^{\circ}\text{C}$ ($^{\circ}\text{F}$)				
in.	mm		T	J	E	K	N
1/25	1	32	260° (500°)	260° (500°)	300° (570°)	700° (1290°)	700° (1290°)
1/16	1.6	28	260° (500°)	440° (825°)	510° (950°)	920° (1690°)	920° (1690°)
1/8	3.2	22	315° (600°)	520° (970°)	650° (1200°)	1070° (1960°)	1070° (1960°)
3/16	4.8	19	370° (700°)	620° (1150°)	730° (1350°)	1150° (2100°)	1150° (2100°)
1/4	6.3	16	370° (700°)	720° (1330°)	820° (1510°)	1150° (2100°)	1150° (2100°)
3/8	9.5	13	370° (700°)	720° (1330°)	820° (1510°)	1150° (2100°)	1150° (2100°)

4.3.3 High Temperature Thermocouple Measurements

The design of a high temperature thermocouple should be treated as a system where the sheath, the mineral oxide insulation, and the element material are mutually compatible. The sheath material should resist corrosion, spalling, and embrittlement. The element material of the thermocouple should be compatible with its environment.

The sheath and the mineral oxide insulation should be chemically compatible for the process conditions. For example, in furnaces, oxidation is a problem while, in a hydro-treating process, hydrogen diffuses through protective metal sheath and attacks the elements. If the sheath's chemistry and conductors are similar, the potential for diffusion of elements between them is reduced. This reduces the downward drift in the output that frequently occurs with high temperature measurements. Further, the sheath and element material have a similar coefficient of expansion which reduces cold working.

Some sheaths work better with gas fuels while others (e.g. UNS N06002) are superior at dealing with oil fuels.

The Chromel thermo-elements limit the application of Type E and K thermocouples. Chromel can develop a condition known as "green rot." This is caused by the preferential oxidation of the chromium in Chromel. The readings can shift downwards as much as 17 °C (30 °F) from the actual temperature prior to thermocouple failure. This attack is severe in low or marginal oxygen atmospheres, less severe with high oxygen levels but nonexistent at zero oxygen levels.

Since hydrogen attacks Chromel they should not be used with reducing atmospheres. At high temperatures it is possible for hydrogen to diffuse through the thermowell and sheath. This attack is severe at temperatures between 815 °C and 1040 °C (1500 °F and 1900 °F.)

Thermal aging of the Chromel thermo-element in both Type E and K thermocouples occurs primarily between 149 °C and 482 °C (300 °F and 900 °F). Thermal aging tends to increase the thermocouple EMF. The shift depends on the temperature history, previous cold working, impurities and the sheath material.

Many of the thermoelectric property changes are attributed to "atomic ordering." When a Type K thermocouple is used in the drifting temperature zone, some of the atoms of the positive thermo-element rearrange themselves from a random state into an ordered state. This atomic rearrangement changes the EMF output. This shift can result in a positive error of 1.7 °C to 2.8 °C (3 °F to 5 °F) for a Type K thermocouple. The Type E thermocouple has a smaller aging error. Stabilized thermocouple wire is recommended to address this problem.

Type E and Type K thermocouples also suffer severe attack from sulfurous atmospheres at high temperatures. Sulfur attacks both thermo-elements and causes rapid embrittlement and breakage of the negative wire through intergranular corrosion.

ASTM E230 Type N thermocouples have better performance in these situations. It has improved resistance to positive lead aging and less oxidation drift at temperatures ≥ 1095 °C (2000 °F) as well as withstanding sulfur attack better.

At higher temperatures heavier wire decreases aging and cold working but with increased response and conduction errors. Sheath material is generally available in stainless steel and nickel-chromium-iron alloys. Thermocouple degradation can be combated partly by using heavier gauge wire; e.g. eight gauge. Heavier wire is stronger so it resists cold working and it takes longer for impurities to affect the total molecular structure.

Thermal aging is also be controlled by using a nickel-chromium-iron alloy sheath; e.g. N06600, in place of a stainless steel sheath. The expansion for a N06600 sheath is more similar to the expansion of thermocouple wire than is stainless steel. This reduces thermocouple cold working. Plus, the potential for element diffusion is less which reduces drift.

4.3.4 Skin Tube Temperature Measurement

Welded Type K or N thermocouples are used to measure furnace skin tube temperatures. Furthermore, welded thermocouples are also attached to coke drums and reactor wall surfaces to manage temperature gradients during startup.

Tube skin thermocouples are used to warn against overheating from reduced fluid flow or coking inside the tubes. The tube skin thermocouples are located at the maximum temperature points. For coking prone feeds, tube skin measurements are typically made within two or three rows of the outlet. Multiple skin thermocouples along the potential coking areas are commonly provided.

Given their high failure rate, two or more tube skin thermocouples are recommended on critical tube sections. Measurement locations are determined by evaluating the tube temperature profile. Tube skin thermocouples are located on tube sections near their yield point or where the temperature profile is the highest. See API 556 for further recommendations concerning thermocouple locations.

Tube skin thermocouples provide diagnostic information. The full thermal history of a tube provides a better tube life estimate. The lost tube life can be determined from the temperature and duration of a thermal excursion.

A tube skin thermocouple should have a life span that exceeds the furnace turnaround time, which is in excess of two years. This is accomplished by using resistant materials, simplex eight gauge wire, protective radiation covers and installations that limit stress. The thermocouple sheath material should be suitable for the furnace environment, e.g. N06600. Some of the more common sheath materials used in furnaces include:

— AISI 310SS	— N06002	— N06600
— AISI 446SS	— N12160	— N06617

The thermocouple needs to be properly attached to the tube as shown in Figure 8. Care should be exercised to minimize the mass at the point of measurement. Additional mass slows the response and increases conduction errors. Tube skin thermocouples are often a 20 mm ($3/4$ in.) square by 3 mm ($1/8$ in.) thick pad curved to fit the contour of the tube and attached with a weld bead on three sides.

Another tube skin thermocouples design intended for fast response time is the knife edge element. The knife edge tube skin thermocouples (see Figure 9) can be provided with a 12 mm ($1/2$ in.) diameter heavy wall sheath. However, the multi-pass weld needed for this type of thermocouple causes additional stress that can reduce tube life. Modified versions of knife edge thermocouples (e.g. the fan type element) have also been developed which reportedly improved accuracy and service life.

To increase reliability, consideration should be given by having the thermocouples fabricated to selected parts of ASTM E235. Taking a radiographic thermocouple junction according to 6.3 to ensure its uniformity is recommended. A properly fabricated tube skin thermocouple can operate successfully for over six years.

Flexibility should be adequate to accommodate furnace tube expansion. Skin tube thermocouple sheaths can extend over 15 m (50 ft). Type S expansion loops (see Figure 8) should be provided along long tube sections to compensate for differential growth. Coiled sheaths should be provided just prior to the refractory to compensate for tube movement. The coils should be orientated in the direction of movement.

Gaps between the tube and the thermocouple sheath should be minimized. Gaps cause higher readings because the element is reading the firebox temperature. Also the sheath will deteriorate more rapidly when it is not cooled by the furnace tube. The contact area should be free of scale and oxide. Mounting clips should be welded along the cooler rear side of the tube to hold the thermocouple sheath. A typical design for attaching these thermocouples is shown in Figure 8.

To prevent radiant heat from affecting the measurement, shields can be added which curve around the pipe and over the junction and are packed with a thermally opaque insulation (see Figure 7). The radiation shield should be welded to the tube as shown in Figure 7 along its area of contact.

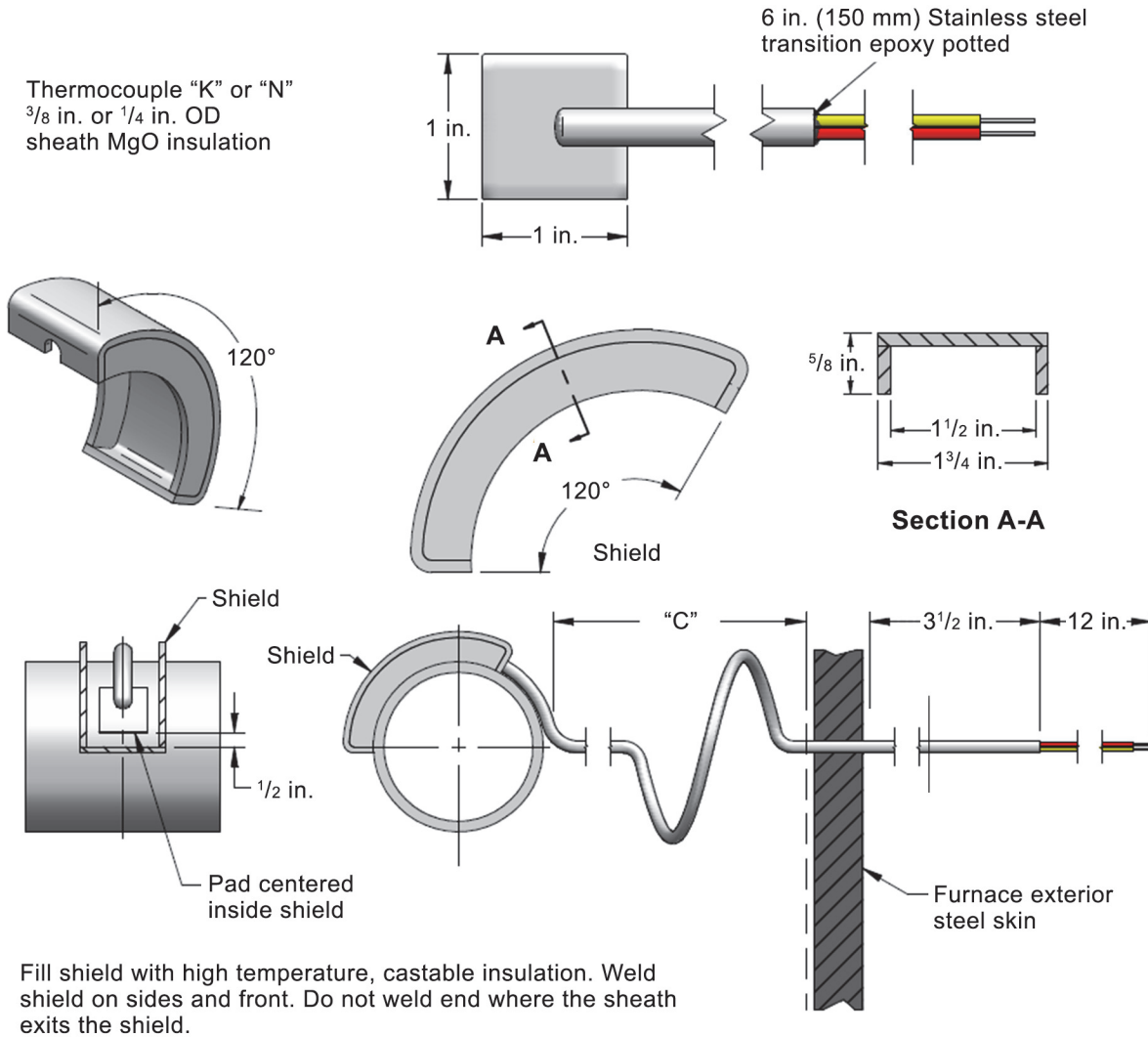


Figure 7—Type Skin Thermocouple with Radiation Shield

Outside the furnace, the tube skin sheath can be run through a thermocouple compression fitting. See Figure 10. The compression fitting is threaded into a coupling that is part of the furnace shell. The free end of the sheath is terminated in a thermocouple head. A second compression fitting is used to attach the sheath to the thermocouple head. The connection head should be provided with a support welded to the furnace shell; otherwise it would be only supported by the thermocouple sheath.

Alternatively, tube skin elements can be run into a nipple with an internal compression fitting. The compression fitting is threaded into a bulkhead that is welded inside the nipple. In turn the nipple is attached to a connection head with a pipe union fitting. Figure 8, Detail A-A shows this construction.

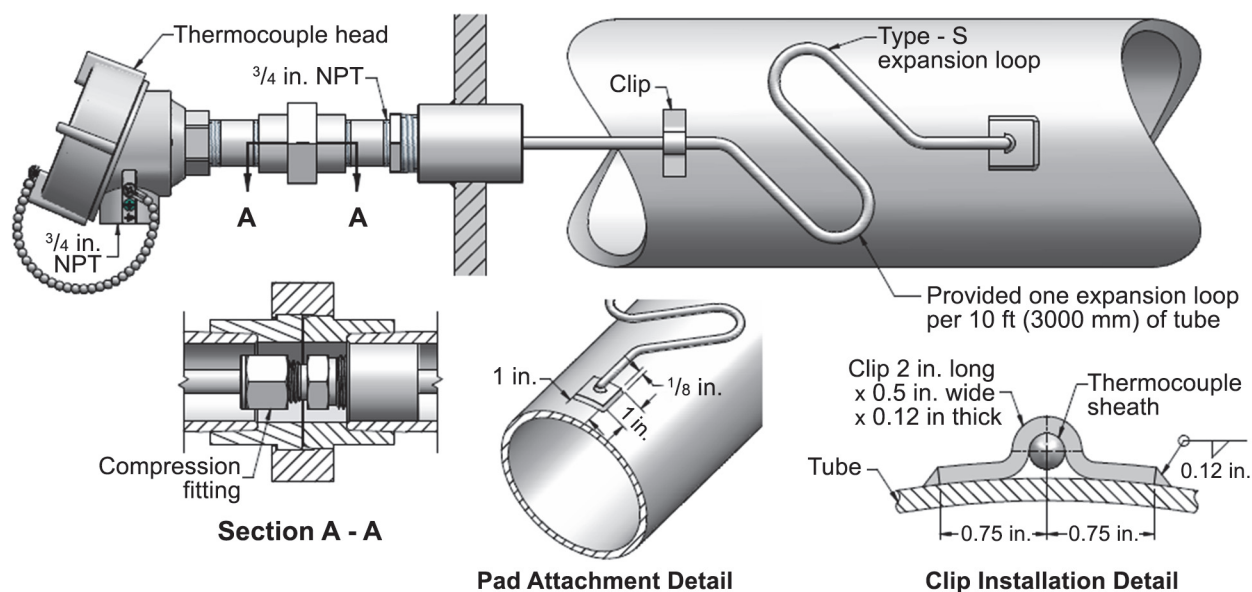


Figure 8—Fixed Thermocouple Head and Sheath with Type S Expansion Loop

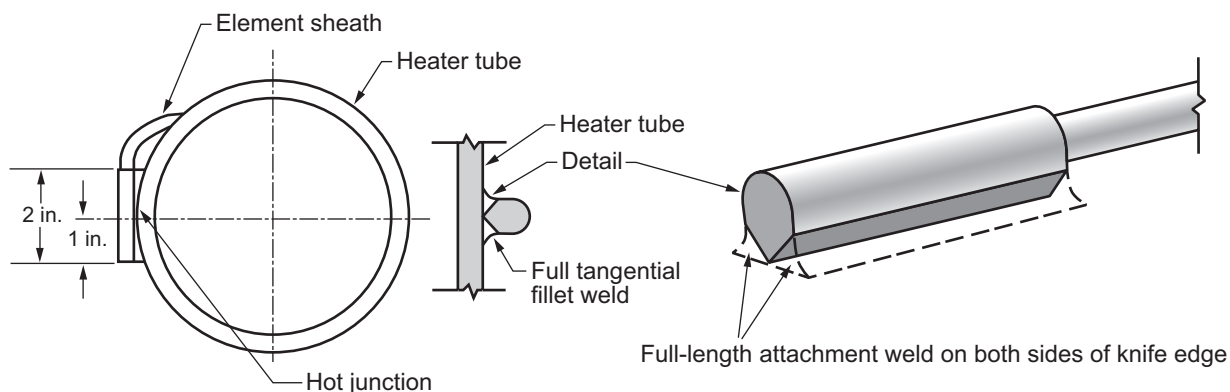


Figure 9—Knife Edge Tube Skin Thermocouple

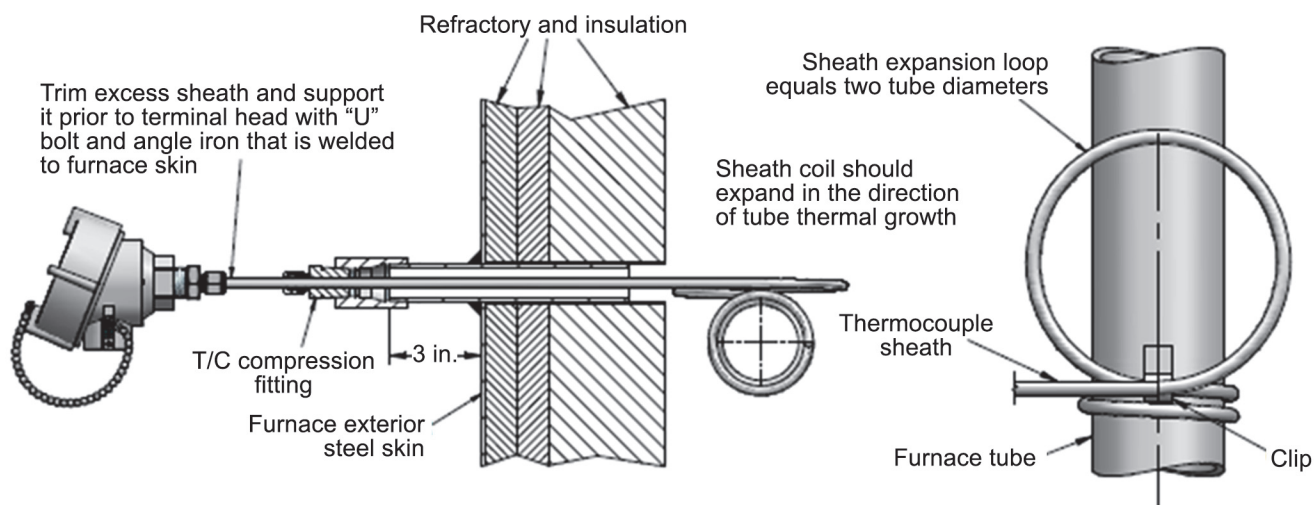


Figure 10—Furnace Tube Skin Thermocouple

4.3.5 Thermocouple Extension Wire

Thermocouples should use the correct extension wire according to ASTM E230 standards. Thermocouple extension wires are available in pairs and multiple pair bundles. Single pair thermocouple extension wire is normally 16 AWG. Wire 20 AWG and smaller are normally used in multi-pair cables. Thermocouple wire is color code by type. In North American and much of South America the color codes are determined according to ASTM E230 with red always being the negative wire. IEC 60584-3 is used elsewhere when a national standard does not apply.

Each extension lead is made from the same materials as the thermo-elements. Materials for thermocouple extension wires are listed in Table 2. Ordinary wire causes errors by creating parasite voltages at each junction. Low accuracy extension wire makes the use of Special Tolerance thermocouples ineffective so a temperature transmitter is recommended at the thermocouple. For limits of error associated with extension wires, refer to ASTM E230.

It is best to minimize thermocouple junctions or terminations. When junctions cannot be avoided, terminal blocks made from the thermocouple material can be provided. Also standard terminal blocks that operate at a constant temperature minimize parasite voltages.

Extension wires should be separated and installed as described in API 552. For the best accuracy, terminations should be eliminated with the extension wire run straight to the converter. The easiest method converts the signal immediately at the thermocouple connection head (see Figure 14).

A significant economic advantage can be achieved by using a transmitter and ordinary wiring to the control system. Transducers in a EN 50446-2006 Form B package fit inside a standard thermocouple head so no additional accommodations are needed. See 8.9 for further information about temperature transmitters.

4.4 Resistance Temperature Devices

4.4.1 General

Resistance temperature measurements provide a more accurate measurement than thermocouples. Resistance elements are used in installations where improved accuracy is needed; e.g. differential temperature measurement.

RTDs (Resistance Temperature Devices) use the principle that a material's electrical resistance changes with temperature. Three types of wire are generally used for resistance elements. Nickel is used for temperatures up to 315 °C (600 °F) and platinum, the most accepted and accurate, is used for temperatures up to 650 °C (1200 °F). A third type, copper, is used in large motors for temperatures up to 150 °C (300 °F).

Table 6 lists some of the other materials used for temperature measurement.

Table 6—Standard Resistant Temperature Elements

Type	Remarks
Platinum	IEC 60751/ASTM E1137 Standard Curve
Nickel	DIN 43760 Standard Curve
Copper	Edison Winding No 15
Balco Nickel-Iron Alloy	Ni-Fe ASTM B267-2007 Class 8

4.4.2 Calibration

Platinum temperature measurements can be used from –200 °C to 650 °C (–330 °F to 1200 °F) but the practical range is from –200 °C to 450 °C (–330 °F to 840 °F).

The most common curve used in petrochemical services is the IEC (DIN) curve, with $\alpha = 0.00385 \, \Omega / \Omega / ^\circ\text{C}$. The United States traditional "Industrial Standard" Platinum curve has an $\alpha = 0.003902$ and is still provided with some motors and other non API equipment. Prior to 1980, the SAMA curve, $\alpha = 0.00392$, was often provided. These curves are based on a sensing element resistance of $100 \, \Omega$ at $0 \, ^\circ\text{C}$. Table 7 lists some of the RTD standards and their alphas. The use of polynomial equations with between two and four terms, depending on the element, is needed.

Table 7—Alternate Resistant Temperature Elements

Material	α	Base Ω	Base T	Remarks
Platinum	0.003902	100	$0 \, ^\circ\text{C}$	USA "Industrial Standard"
Platinum	0.003920	100	$0 \, ^\circ\text{C}$	MIL-T-24388
Platinum	0.003923	100	$0 \, ^\circ\text{C}$	Legacy SAMA Standard
Platinum	0.003916	100	$0 \, ^\circ\text{C}$	JIS C1604
Platinum	0.003911	100	$0 \, ^\circ\text{C}$	GOST
Copper	0.004274	10	$25 \, ^\circ\text{C}$	Edison Winding No 15
Nickel	0.00618	100	$0 \, ^\circ\text{C}$	DIN 43760
Nickel	0.00672	120	$0 \, ^\circ\text{C}$	USA Legacy Standard
Ni-Fe Alloy	0.00518	1000	$20 \, ^\circ\text{C}$	NiFe more linear than Ni
Tungsten	0.00456		$20 \, ^\circ\text{C}$	High Temperature $\geq 1000 \, ^\circ\text{C}$

IEC 60751/ASTM E1137 Platinum RTDs are available in two accuracy types: Class A $\pm 0.15 \, ^\circ\text{C}$ @ $0 \, ^\circ\text{C}$ and Class B $\pm 0.30 \, ^\circ\text{C}$ @ $0 \, ^\circ\text{C}$. By using Callendar-Van Dusen constants, more accurate RTDs can be fabricated if required. See Figure 11 for an illustration of the two accuracy classes. IEC 60751 has a Class AA curve as well with $\pm 0.10 \, ^\circ\text{C}$ @ $0 \, ^\circ\text{C}$.

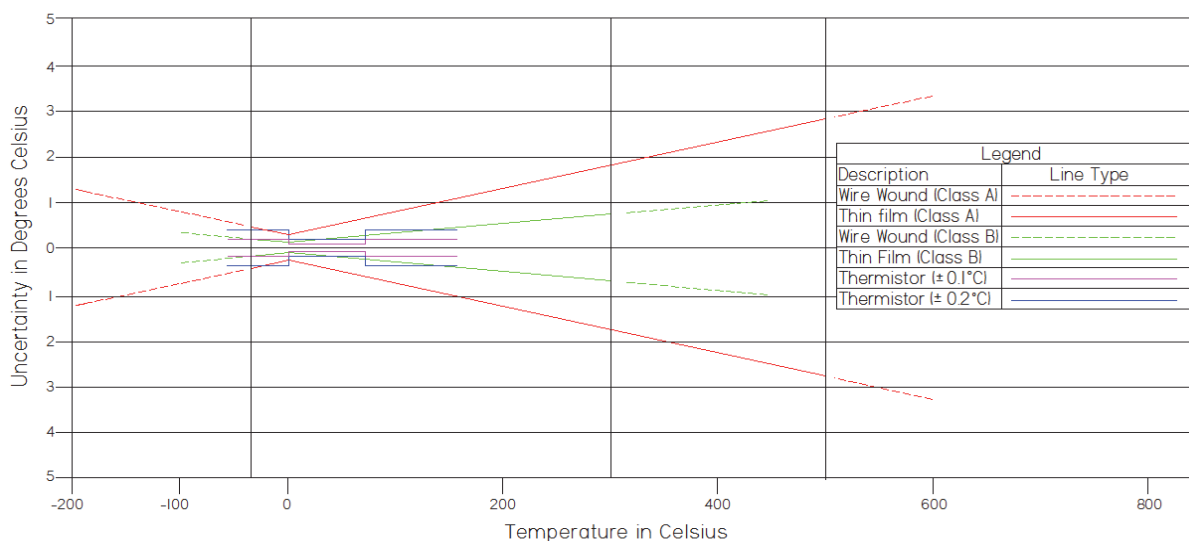


Figure 11 – ACCURACY LIMITS AND USABLE TEMPERATURE RANGES FOR THERMISTORS AND RTDs

Figure 11—Accuracy Limits and Usable Temperature Ranges for Tthermistors and RTDs

4.4.3 Fabrication

Platinum RTD elements are either wire-wound or thin film. The wire-wound type is the normal choice for refinery processes due to its durability and broader range and has a 25 mm (1 in.) sensitive length. Wire-wound RTDs also have superior interchangeability and stability at high temperatures. Thin film RTDs are more durable in high vibration applications with same the accuracy but have a reduced temperature range. They are preferred for high velocity gas applications.

Wire-wound elements are made by winding a wire strand onto a mandrel until it equals 100 ohms at 0 °C (32 °F). The sensing wire is then covered with a nonconductive protective coating.

Another type of wire-wound element is made winding a fine strand of platinum wire into a coil. The coil is then inserted into a mandrel and ceramic is packed around the sensor to prevent it from shorting. The ceramic powder cushions the coils. This construction is strain-free as well as vibration and shock resistance. RTDs fabricated to meet ASTM E1137 withstand 3 G of vibration and 50 G of shock for 11 milliseconds.

The manner in which the wires inside the probe are insulated is a limitation that can prevent using an off-the-shelf RTD at high temperatures (above 200 °C/392 °F). Some RTD designs use plastic or fiberglass insulated wire that is directly attached to the element. This limits the element's maximum working temperature.

According to ASTM E1137, to achieve their entire range a RTD should use nickel plated copper, nickel, platinum, constantan, or manganin alloy wire encased in MgO. These materials should be used along the entire sheath length to the transition piece. Copper wires are then attached. The connections should be welded.

Hermetic sealing of the transition piece is recommended. The potting at transition piece provides a moisture barrier around the external lead wire. For temperatures greater than 200 °C (390 °F) moisture resistant ceramic or similar adhesive should be used.

4.4.4 Application

The most commonly used RTD is the tip sensitive, three-wire type with two measurement wires and one wire compensation wire. The compensation wire corrects for the resistance of the extension wire. Two wire and four wire versions are also available. The two-wire type is used mostly where space is limited, such as motor windings and in bearing housings. When this type of element is used to provide compensation, the third conductor extension wire is terminated with one of the measurement wires at the point nearest the measurement element. Conversely, four-wire RTDs are available with the fourth wire used for additional compensation. They are used when more accuracy is desired.

Another type of platinum RTD is the averaging type. It is available in lengths near twenty meters (seventy feet) and it useful for measuring the average air temperature into winterized air coolers or heater air ducts.

It is recommended that tip sensitive Platinum RTDs be fabricated according to ASTM E1137 and specified with a –200 °C to 650 °C (–330 °F to 1200 °F) range as a Class A device. This ensures that the element has the necessary capabilities.

The precautions and practices applicable to thermocouples are also applicable to RTDs, with the following exceptions.

- a) Nickel alloy sheathes should be provided for temperatures ≥ 260 °C (500 °F).
- b) To compensate for lead wire resistance, two wires are connected at one end of the RTD. The most common wiring is with a triad cable.

- c) RTDs experience a self-heating problem when using simple resistance transducers. Low current devices are recommended.

At high temperatures hydrogen or metal vapors can gradually and permanently shift the Platinum RTD calibration. Hydrogen permeates through the thermowell and sheath from the process while the metallic vapor comes from the sheath and lead wires.

4.4.5 RTD Extension Wires and Signal Transmission

Ordinary copper wire is used to connect the instrument to the RTD sensor. Lead wire insulation should be color coded according to IEC 60751. Using a locally mounted transmitter is preferred. This allows the use of standard signals and provides flexibility in terminating the sensor connections. Transmitters also filter the sensor signal of unwanted electromagnetic interference (EMI).

For systems with multiple RTDs (e.g. machinery monitoring), the wires can be run to a field terminal strip. A multi-conductor 20 or 24 AWG cable containing triads is then used to bring the signals to the monitoring system. However, exceptionally long runs could need a larger gauge wire.

4.5 Thermistors

4.5.1 Selection and Application

Of the three commonly used temperature sensors, thermistors are the most sensitive. They have an interchangeability tolerance of $\pm 0.1^\circ\text{C}$ or $\pm 0.2^\circ\text{C}$ ($\pm 0.18^\circ\text{F}$ or $\pm 0.36^\circ\text{F}$) out to 70°C (158°F) depending on the thermistor and span. However thermistors are limited in their temperature range with a nominal range of 0°C to 260°C (32°F to 500°F). See Figure 11 for an illustration of the two interchangeability tolerances when compared to platinum RTDs.

A thermistor is a composed of sintered metal oxide semiconductor material that exhibits a sizeable resistance change with temperature. Because of their compact size, thermistor elements are commonly used when space is limited. In the refining and petrochemical industry they are usually found in existing equipment; such as motors, power supplies and HVAC systems.

Thermistors usually have negative temperature coefficients (NTC), so the resistance decreases as the temperature increases. However, PTC thermistors have a positive curve and are use in special applications such as current limiting fuses.

Unprotected metal oxide is prone to moisture damage, so they are encapsulated in glass or epoxy. If moisture penetrates the encapsulation, the DC bias voltage causes silver migration that eventually results in electrode shorting.

Finished thermistors are chemically stable so they are not significantly affected by aging. Glass encapsulated thermistors are more stable than RTDs according to the National Institute of Standards and Technology (NIST). Since thermistors are small they respond quickly to temperature changes but this also makes them susceptible to self-heating errors.

Mechanically the thermistor is a simple and reliable sensor. The most common thermistor is a two wire bead. The bead diameter ranges from 0.5 mm (0.02 in.) to 5 mm (0.2 in.). The beads are more fragile than RTDs or thermocouples but thermistors are available in stainless steel sheaths.

Thermistors are usually designated according to their resistance at 25°C (77°F). The most common is the 2252 ohms thermistor. Many devices accept the 2252 ohm, Curve B thermistor. Other common sizes are 5000 and 10,000 ohms.

The high resistance of a thermistor gives it an advantage. A three or four wire connection is not needed as with RTDs. For example, a 5000 ohms thermistor with a temperature curve of 4 % per °C and a lead resistance of 100 ohms only has a 0.05 °C (0.09 °F) error.

However, because they are semiconductors thermistors are more susceptible to permanent calibration loss at high temperatures. Extended exposure above their operating limits causes them to drift.

4.5.2 Linearization

The resistance-temperature relationship of a standard thermistor is negative and nonlinear. The thermistor's resistance to temperature relationship given by the Steinhart & Hart equation:

$$T = (a + b(\ln R) + c(\ln R)^3)^{-1}$$

Where a , b , and c are constants, R is the thermistors resistance in ohms and T is the absolute temperature in Kelvin's. The constants are normally determined uniquely for each application by solving three simulations equations with values selected from a table for the selected element.

While the Steinhart & Hart equation is a close fit, it does not always provide the precision needed across the full range of -80 °C to 260 °C (-112 °F to 500 °F). This can be corrected by fitting the Steinhart & Hart equation over 50 °C (122 °F) or 100 °C (212 °F) increments and then splicing these fits to cover the needed range.

Below are guidelines that show the interpolation error for each temperature span:

- a) ≤ 0.003 °C error for 50 °C temperature spans within $0\text{ °C} \leq t \leq 260\text{ °C}$
(≤ 0.005 °F error for 90 °F temperature spans within $32\text{ °F} \leq t \leq 500\text{ °F}$)
- b) ≤ 0.02 °C error for 50 °C temperature spans within $-80\text{ °C} \leq t \leq 0\text{ °C}$
(≤ 0.04 °F error for 90 °F temperature spans within $-112\text{ °F} \leq t \leq 32\text{ °F}$)
- c) ≤ 0.01 °C error for 100 °C temperature spans within $0\text{ °C} \leq t \leq 260\text{ °C}$
(≤ 0.02 °F error for 180 °F temperature spans within $32\text{ °F} \leq t \leq 470\text{ °F}$)
- d) ≤ 0.03 °C error for 100 °C temperature spans within $-80\text{ °C} \leq t \leq 25\text{ °C}$
(≤ 0.05 °F error for 180 °F temperature spans within $-112\text{ °F} \leq t \leq 77\text{ °F}$)

Alternatively, it is possible to determine the three constants by a bench calibration at three different temperatures and solving three simultaneous equations based on the Steinhart & Hart equation.

For use with a standard resistance meter, linearization is possible by connecting a resistor in parallel with the thermistor. The value should equal the thermistor's resistance at the mid-range temperature. The result is a significant reduction in non-linearity. However, this is only recommended when resolution less than 0.1 % is acceptable.

4.6 Distributed Temperature Sensing

Fiber optic distributed temperature sensing systems (DTS) are used to monitor surface temperatures of vessels or pipe. Temperatures are measured along the fiber optical cable continuous profile. Measurements are achieved over extended distances making it useful for pipeline monitoring. Resolution within 1 m (3 ft) with accuracy to within ± 1 °C (1.8 °F) is possible. With spiral wrapping and other techniques tighter spatial resolution is possible.

4.7 Radiation Pyrometers

Non-contact pyrometers or radiation thermometers operate between -30°C and 3900°C (-22°F and 7050°F) and they have a rapid response. In refineries they are used mostly in high temperature services; e.g. fired heaters, sulfur reactors. There are a number of different technologies used:

- a) Broad Band Infrared;
- b) Narrow Band Infrared;
- c) Two Color Ratio;
- d) Infrared Thermocouple;

Pyrometers come in various forms and have different power requirements. Some devices operate on a two wire 4-20 mA circuit. Infrared thermocouples are self-powered, using infrared radiation to produce a standard thermocouple signal. They cover temperatures from -45.6°C to 260°C (-50°F to 500°F) over the 6.5 to 14 micron spectral range.

To measure the true temperature, the effective emissivity has to be determined. This is accomplished using the radiation laws or by calibrating the pyrometer with the material at a known temperature.

Materials property changes affect the emissivity. For instance as materials oxidize, emissivity tends to increase. Errors also occur if the target reflects radiation from other hotter surfaces, including sunlight. Also errors can be introduced if the path is obstructed by absorbing materials; e.g. fumes, smoke, or glass.

Emissivity uncertainties are reduced using short wavelengths or by ratio radiation techniques. Short wavelengths, around 0.7 microns, are effective. There is a high signal gain at these wavelengths. Also, selecting a device with the appropriate narrow band helps compensate for reflection and absorption problems. Controlling the field of view assists in obtaining a reliable measurement. If the target size is smaller than the object being measured the reading is more precise. Also, taking the measurement perpendicular to the target eliminates reflection issues.

It is important to keep the sight path clear and to keep the optical elements clean. Purge assemblies are recommended for cooling and for keeping the lens clear. A typical installation is shown in Figure 12. Also the use of high quality fiber optic cable between the sensor and the viewing port has proven effective in protecting the sensor for overheating. Fiber cables operate at 200°C (390°F), which mostly eliminates the need for external cooling.

The user needs to investigate the application, select the optimum technology, determine the compensation methods and design the installation with a supplier who is knowledgeable about the application. See ASTM E2758 for further information on pyrometer application.

4.8 Temperature Element Wiring

Except for thermistors, wire junctions and terminations should be minimized since the low impedance sensor wires are susceptible to electromagnetic interference (EMI). Temperature element wire extensions should terminate in either a connection head or a transmitter.

Transmitters amplify the low impedance sensor signal to a more robust high-level signal to improve the integrity of the temperature measurement to the control system. It is recommended the transmitter be mounted close to the sensor to minimize the pickup of EMI noise.

Armored cable attached to the temperature element sheath is recommended to separate the thermowell from the conduit. See Figure 13. When a connection head is mounted on a thermowell, the conduit should be vented to allow the process fluid to escape upon thermowell failure. Also a seal should be provided between the vent and the junction box.

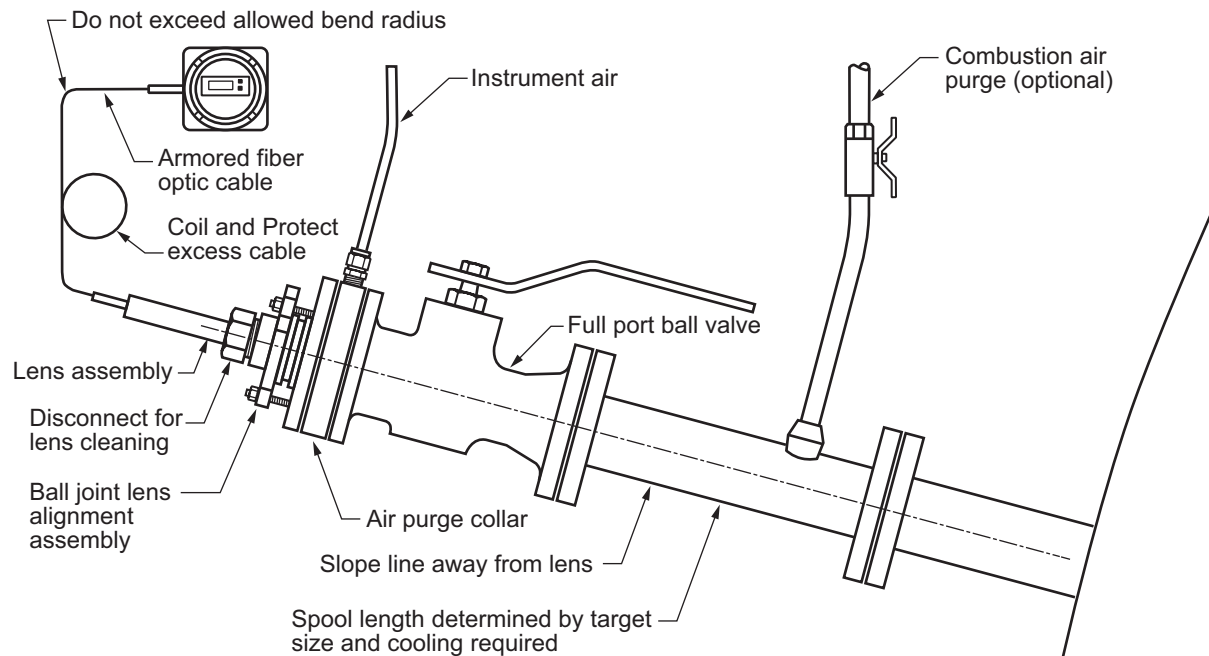


Figure 12—Example Pyrometer Installation for Claus Reactor

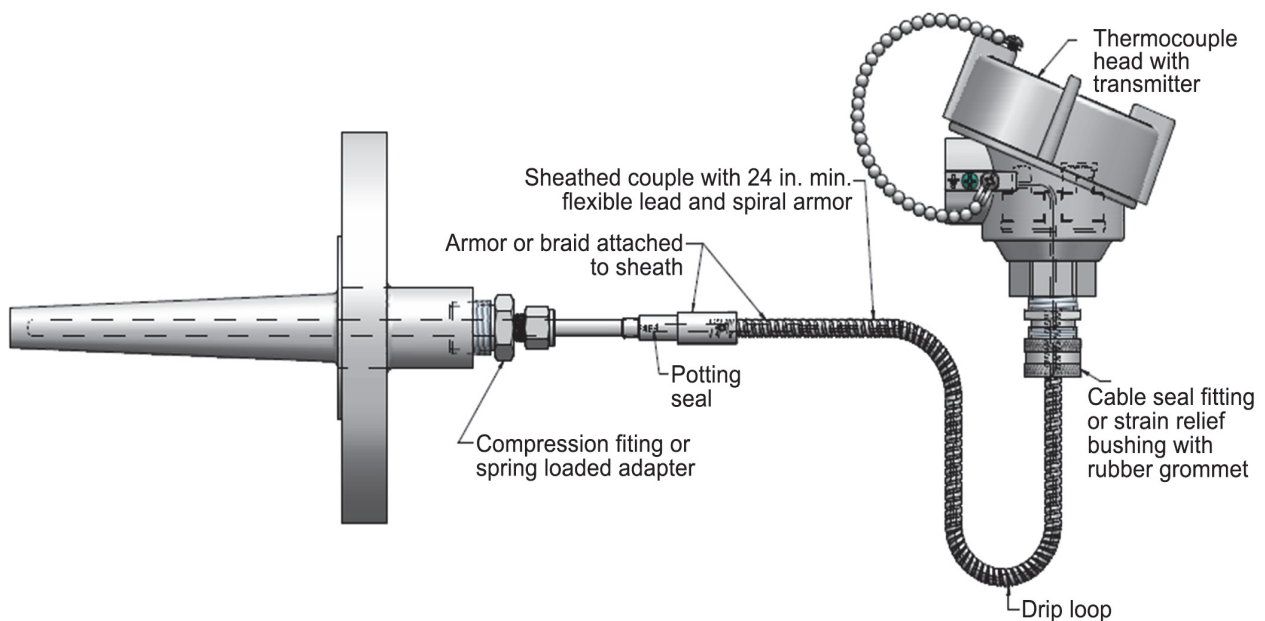


Figure 13—Sheathed-type Thermocouple with Armored Lead

4.9 Temperature Signal Conditioners and Transmitters

A temperature signal conditioner or transmitter receives a sensor's low impedance signal, amplifies it and generates a standard output signal. These devices have a high input impedance to ensure that input signals are maintained at appropriate values. They also have high common mode rejection to control electromagnetic noise.