# Table of Contents

## Cover Control Systems Engineer (CSE)

- Notice from the Publisher

## Table of Contents

- Introduction to This Study Guide
  - About the Author
  - People who have contributed to the previous editions of this manual

## Tips on How to Use This Study Guide

- Using Thumbnails to Navigate
- Using Bookmarks to Navigate
- Important File Attachments - Open by clicking on the paper clip!
- How to Print this Manual

## Welcome to Control Systems Engineering

- Licensing as Professional Engineer / Control Systems Engineer (CSE)
- Why Become a Professional Engineer?
- This is the third edition of this study manual
- The new and expanded sections include:

## Recommended Flow Chart of Study for the CSE

- Overview of Recommended Flow Chart of Study for the CSE

## Examination General Information

- State Licensing Requirements
- Eligibility
- Exam schedule
- Description of Examination

## Exam content

- I. Measurement
- II. Signals, Transmission, and Networking
- III. Final Control Elements
- IV. Control Systems
- V. Safety Systems
- VI. Codes, Standards, Regulations

## Exam Scoring

## Reference Materials for the Exam

- Recommended Books and Materials to Take to the Exam
- Books and Materials for Testing
- Books for Additional Study
- Courses for Additional Study
- ISA Control Systems Engineer (CSE) PE Review
- Industrial Network Training
- Control Systems Engineer (CSE) Supplement Course
- Online Process Plant @ Learn Control Systems.com
Control Valve Sizing

Common Plant Analyzers
Boiling Point Analyzers
Vacuum Distillation Analyzer
Flash Point Analyzer
Cloud Point Analyzer
Freeze Point Analyzer
Pour Point Analyzer
Color Analyzer
Combustion and Analyzers
Combustion furnace and air-fuel ratio control
Air-Fuel ratio control utilizing CO and O$_2$ concentrations
BMS - Burner Management Safety
OSHA Requirements
Carbon dioxide (CO$_2$) reading
Examples of Process Analyzers
Select the appropriate analyzer and configuration
Typical Analyzer Piping and Control Schematic

Process Control Valves and Actuators
Considerations when sizing a control valve
Flow Coefficient Cv
Specific Gravity
Operating Conditions
ISA standard valve symbols
ISA standard pressure regulating valve symbols
Valve actuators
ISA standard actuator symbols
Limit switches on a valve - ISA standard symbol
Calculating the size of the actuator
Example actuator sizing
Split ranging control valves
Valve positioner applications
ISA standard valve positioner symbols
Summary of positioners
When should a positioner be used?
Electrical positioners
Control valve application comparison chart
Understanding flow with valve characteristics
What is the ΔP for valve sizing?
System piping ΔP pressure drops
Control valve ΔP pressure drop
Graph of the Inherent valve characteristics (off the shelf)
Which valve characteristic trim to use?
Characteristic distortion in valves
Gain and Rangeability (turndown ratio in valves)
Proper control valve sizing
Oversized valves present problems
Experiment and understand Installed valve characteristics
Summary of control valve characteristics
Control Valve Sizing
The Valve Sizing Equations
Review of Frequency Response Fundamentals ....................................................... 215
Electrical Application – A First Order System .................................................. 215
Bode Plot of First Order System ................................................................. 216
Calculate the data for the Bode Plot ............................................................ 217
Creating a Bode Plot – First Order System using Frequency .................... 220
Hydraulic Application – A First Order System ........................................... 221

Process Control Theory and Controller Tuning .............................................. 223
Degrees of Freedom in Process Control Systems ...................................................... 223
Controllers and control strategies (models-modes) .............................................. 225
Process Loop Gain (Gp) .................................................................................. 227
Process Signal Linearization ........................................................................... 228
Signal Filtering in Process Control ................................................................. 230
Applying Signal Filters .................................................................................... 230
Filter Time Constant and Sample Time ............................................................ 231
Example of Filter Time Selection .................................................................... 232
DCS/PLC Sample and Scan Time Consideration ............................................. 233
Sampling time ................................................................................................ 233
Time per scan cycle ....................................................................................... 233
Tuning of Process Controllers ........................................................................ 234
Closed Loop Tuning of the Controller ............................................................ 234
Example: Tune Using Ultimate Gain (continuous cycling) .......................... 235
Open Loop Tuning of the Controller .............................................................. 236
Example: Tuning using Process Reaction Curve (Step Response) .................. 238
Advanced Tuning Methods for Controllers .................................................... 239
The Integral Criteria Method ........................................................................ 239
Lambda Tuning Concepts ................................................................................ 239
Example Reactor Ratio Timing ....................................................................... 242
IMC Tuning Method ....................................................................................... 243
PID Controller Models ................................................................................... 244
Trial and Error Tuning Method ....................................................................... 244
Dead Time and PID Control ........................................................................... 244
PID Tuning Video - Parameters in Action ....................................................... 244
Process Characteristics from the transfer function ......................................... 245
Poles, Zeros, and Dampening from the Transfer Function ............................... 245
Find the Poles from the Function .................................................................... 246
Find the Damping from the Function ............................................................... 246
Find the Time Constant ................................................................................ 247
Find the Period............................................................................................... 247
Find the Time Constant from the Period ...................................................... 247
Find Overshoot and Peak Value ..................................................................... 247
Block Diagram Algebra.................................................................................. 248

Review of Feedback Control Fundamentals ..................................................... 209
Compare Open Loop Control to Closed Loop Control ................................ 209
Open Loop Example – A Mathematical Analysis .............................................. 209
Closed Loop Example – A Mathematical Analysis ......................................... 211
The Transfer Function for the Automobile .................................................... 213
Communications and Industrial Control Networks ......................................................... 257
Overview of Corporate and Plant Networks ................................................................. 257
Open System Interconnect (OSI) and TCP/IP network layer model .............................. 259
  7 Layers of networking in the OSI model ................................................................. 259
      Physical (Layer 1) ............................................................................................... 259
      Data Link (Layer 2) ............................................................................................ 259
      Network (Layer 3) .............................................................................................. 259
      Transport (Layer 4) ............................................................................................ 259
      Session (Layer 5) ............................................................................................... 260
      Presentation (Layer 6) ....................................................................................... 260
      Application (Layer 7) ......................................................................................... 260
Cisco Network Certification – IIOT (Industrial Internet of Things) for IT and OT ....... 260
      The typical network model ................................................................................ 261
      The Network Essentials ...................................................................................... 263
Overview of Industrial Networks .................................................................................. 264
      The most popular industrial networks and their applications are below .......... 264
      HART Networks ................................................................................................. 265
         Traditional HART Network .......................................................................... 265
         A Wired HART Network .............................................................................. 266
         A Wireless HART Network ......................................................................... 266
      PROFIBUS and AS-i Networks ......................................................................... 267
         Reasons for choosing PROFIBUS ................................................................. 267
         PROFIBUS DP ................................................................................................. 267
         PROFIBUS PA ................................................................................................. 268
         PROFINET ....................................................................................................... 268
         AS-i .................................................................................................................. 268
         PROFIBUS Fieldbus Message Specification (FMS) ........................................ 269
         FOUNDATION Fieldbus ............................................................................... 269
            Reasons for choosing FOUNDATION Fieldbus ....................................... 270
         H2 or HSE (High Speed Ethernet) ................................................................. 270
         FOUNDATION H1 .......................................................................................... 270
         Typical FOUNDATION Segments ............................................................... 271
         Use of the OSI Networking Layers ............................................................... 271
      Rockwell and ODVA (CIP) Networks ................................................................ 272
         ControlNet ...................................................................................................... 272
         DeviceNet ....................................................................................................... 273
         EtherNet/IP ..................................................................................................... 274
         CompoNet ...................................................................................................... 274
         DH485, DH+, RIO ......................................................................................... 274
      Modbus Networks ............................................................................................... 275
         Traditional Modbus Networks ..................................................................... 275
         Communication and Devices .......................................................................... 275
<table>
<thead>
<tr>
<th>Topic</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Protocols</td>
<td>275</td>
</tr>
<tr>
<td>EtherCAT</td>
<td>276</td>
</tr>
<tr>
<td>SERCOS</td>
<td>276</td>
</tr>
<tr>
<td>Summary - Automation and Process Control Networks</td>
<td>277</td>
</tr>
<tr>
<td>Plant Facility Monitoring and Control System (FMCS)</td>
<td>277</td>
</tr>
<tr>
<td>BACnet</td>
<td>278</td>
</tr>
<tr>
<td>LonWorks</td>
<td>278</td>
</tr>
<tr>
<td>Typical Building Automation Network</td>
<td>278</td>
</tr>
<tr>
<td>Networked intelligent and smart devices</td>
<td>279</td>
</tr>
<tr>
<td>PID control in intelligent networked devices</td>
<td>279</td>
</tr>
<tr>
<td>PROFIBUS Control Blocks</td>
<td>280</td>
</tr>
<tr>
<td>The Rosemount 333 Tri-Loop to split multiple variable signals</td>
<td>280</td>
</tr>
<tr>
<td>The Application of Digital Logic in Control Systems</td>
<td>281</td>
</tr>
<tr>
<td>Overview of Digital Logic</td>
<td>281</td>
</tr>
<tr>
<td>Digital Logic Gate Symbols</td>
<td>281</td>
</tr>
<tr>
<td>Digital Logic Gate Truth Tables</td>
<td>282</td>
</tr>
<tr>
<td>ISA Binary Logic</td>
<td>283</td>
</tr>
<tr>
<td>Relay Ladder Logic</td>
<td>284</td>
</tr>
<tr>
<td>Standard RLL Symbols</td>
<td>285</td>
</tr>
<tr>
<td>Sealing Circuits</td>
<td>285</td>
</tr>
<tr>
<td>Control System Architectures</td>
<td>286</td>
</tr>
<tr>
<td>DCS Plant Wide Control System Architecture</td>
<td>286</td>
</tr>
<tr>
<td>PLC Control System Architecture</td>
<td>288</td>
</tr>
<tr>
<td>PLC (Programmable Logic Controller) vs PAC (Process Automation Controller)</td>
<td>288</td>
</tr>
<tr>
<td>Controller Application Function Comparison Chart</td>
<td>289</td>
</tr>
<tr>
<td>SCADA Control System Architecture</td>
<td>289</td>
</tr>
<tr>
<td>PLC Programming Languages</td>
<td>290</td>
</tr>
<tr>
<td>PLC Programming (LD) ladder diagram or (RLL) relay ladder logic</td>
<td>291</td>
</tr>
<tr>
<td>PLC Programming (ST) structured text</td>
<td>291</td>
</tr>
<tr>
<td>PLC Programming (FBD) functional block diagram</td>
<td>292</td>
</tr>
<tr>
<td>PLC Programming (SFC) sequential function chart</td>
<td>292</td>
</tr>
<tr>
<td>Writing a Program and Developing a HMI for a Small Systems</td>
<td>293</td>
</tr>
<tr>
<td>RSLogix 5000, ControlLogix PID (PID Enhanced) Function Block Diagram</td>
<td>294</td>
</tr>
<tr>
<td>Motor Control and Logic Functions</td>
<td>297</td>
</tr>
<tr>
<td>Plant Electrical System</td>
<td>297</td>
</tr>
<tr>
<td>Motor Control Center (MCC)</td>
<td>297</td>
</tr>
<tr>
<td>Typical MCC Design</td>
<td>298</td>
</tr>
<tr>
<td>Typical Motor Controller</td>
<td>298</td>
</tr>
<tr>
<td>How to Control a Motor</td>
<td>299</td>
</tr>
<tr>
<td>Starter Auxiliary Contacts</td>
<td>299</td>
</tr>
<tr>
<td>Overload and Fault</td>
<td>299</td>
</tr>
<tr>
<td>The basic NEMA stop-start station</td>
<td>300</td>
</tr>
<tr>
<td>Typical Motor Control Schematic</td>
<td>300</td>
</tr>
<tr>
<td>NEMA and IEC Terminal Designations</td>
<td>301</td>
</tr>
<tr>
<td>NEMA Standards Publication ICS 19-2002 (R2007)</td>
<td>301</td>
</tr>
<tr>
<td>Relays and Contacts</td>
<td>301</td>
</tr>
<tr>
<td>Coil Lettering and Relay Socket Numbers (NEMA and IEC Numbers)</td>
<td>301</td>
</tr>
<tr>
<td>Standard Symbols</td>
<td>303</td>
</tr>
<tr>
<td>Standard Symbols (Continued)</td>
<td>304</td>
</tr>
<tr>
<td>NEMA and IEC Comparisons</td>
<td>305</td>
</tr>
</tbody>
</table>
Hydraulics and Pneumatics ............................................................................................................... 353
Electrical Systems and Power Quality ............................................................................................ 337
Emergency Standby Systems ............................................................................................................ 343
Hydraulics and Pneumatics ............................................................................................................. 353

Conversion from AC to DC to AC PWM........................................................................................ 331
Volts to Hertz Relationship ............................................................................................................. 334
Important Note about Low Frequency in VFDs ............................................................................ 335
VFDs put Noise into the Electrical System ..................................................................................... 335
PID Control with VFD or DC Drive ............................................................................................... 335
Closed loop control with drive electronics ...................................................................................... 335
Block diagram of PID control with feedback operation available on some VFDs ....................... 336
Drive with built-in PID tension control of web or winding reel operation ..................................... 336

Electrical Systems and Power Quality ............................................................................................ 337
Filtering Power and Harmonics ....................................................................................................... 337
Harmonic Neutralizing Transformers .............................................................................................. 337
Filtering of a Harmonics in Power Systems .................................................................................. 338
Passive Filter .................................................................................................................................. 338
Active Filter .................................................................................................................................... 339
Proper Grounding Procedures ......................................................................................................... 341

Emergency Standby Systems ............................................................................................................ 343
Article 700 – Emergency Systems .................................................................................................. 343
Article 701 – Legally Required Standby Systems .......................................................................... 343
Article 702 – Optional Standby Systems ......................................................................................... 343
UPS (uninterruptible power supply) ............................................................................................... 343
UPS and Battery Bank Sizing ........................................................................................................... 344
Load Profile Calculation ................................................................................................................ 347
Battery Sizing Calculation ............................................................................................................... 348
Worked Example – Sizing the Battery Bank .................................................................................. 349
Backup Generator .......................................................................................................................... 351
BMCS Implementation (Building Monitoring and Controls System) ............................................ 352

Hydraulics and Pneumatics ............................................................................................................. 353
Fluid Power Systems ....................................................................................................................... 353
Hydraulic Systems .......................................................................................................................... 353
Pneumatic Systems ........................................................................................................................ 355
Typical Pneumatic System (this type may be found in a manufacturing or chemical plant) ......... 355
Mechanical Flow Diagram of a Large Compressor ......................................................................... 355
Instrumentation Air Header (Fluid Distribution Header or Manifold) ........................................... 355
Pneumatic Schematic of Valve Controller ..................................................................................... 356
I/P Current to Pneumatic Positioner .............................................................................................. 356
Instrument Air Cost - Engineering Economics .............................................................................. 357
Assumption ..................................................................................................................................... 357
Peak air demand ............................................................................................................................ 357
Vendor data ..................................................................................................................................... 357
Include Total Demand ................................................................................................................... 358
Instrument Air Piping and Cost ....................................................................................................... 358
Pipe sizing is just like sizing electrical lines .................................................................................. 359
Caution Using Charts and Graphs .................................................................................................. 359
Interconnects and headers ............................................................................................................. 359
The Target Objectives ..................................................................................................................... 359
Eliminate the pressure drop ........................................................................................................... 360
Air Velocity ..................................................................................................................................... 360
Crunching the Numbers .................................................................................................................. 361
Recover Wasted Heat to Save Money .............................................................................................. 362
Overview of Conveying Technologies

Some common types of conveying systems are as follows:

- Heavy Duty Roller Conveyors
- Flexible Conveyors
- Vertical Conveyors and Spiral Conveyors
- Spiral Conveyors
- Vertical conveyor with forks
- Vibrating Conveyors

Pneumatic and Vacuum Conveyors

- Pneumatic Tube Conveyor Systems
- Large Complex Pneumatic Conveying Systems
- Typical Plant Pneumatic Conveying System
- HMI for Pneumatic Conveying System
- Dilute Phase Systems
- Dense Phase Systems
- Conveying Phase Diagram
- Pressure Distance Relationships

Vacuum Conveying

- A typical vacuum product transportation system
- Vacuum conveying systems and HMI display
- Vacuum conveying system HMI display

Blower operating cost of pneumatic systems

Screw conveying systems

- Screw conveyor instruments
- Mass or bulk flow measurement
- Radiometric measurement for mass flow rate
- Load cell measurement for mass flow rate

Mass flow control of conveying system

- Radiometric measurement for mass flow rate
- Load Cell (Strain Gauge) measurement for mass flow rate

Typical scale systems used on manufacturing lines and in plants

Chemical Process Technology and Equipment

- Process Technologies
- Separation Processes
  - A Typical Horizontal 3-Phase Separator
- Industrial Distillation
  - A Typical Industrial Distillation Process
  - A Typical Distillation Unit
- Industrial Furnaces (Fired Heaters)
  - Industrial Furnaces
  - Fired Heater Control Scheme
- Expansion Tanks and Heat Transfer Fluid
- Vapor Pressure, Boiling and Cavitation in Equipment
  - Vaporization in Equipment
  - Control Valve Applications
  - Pumping Applications
  - Video of Vaporization and Cavitation Phenomenon
- Heat Exchangers
  - Flow Arrangement
  - Shell and Tube Heat exchanger
<table>
<thead>
<tr>
<th>Topic</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>ISA Standards for Documentation</td>
<td>421</td>
</tr>
<tr>
<td>ISA Instrument or Function Symbol</td>
<td>421</td>
</tr>
<tr>
<td>ISA Line Type Symbols</td>
<td>422</td>
</tr>
<tr>
<td>Standard Line Types</td>
<td>422</td>
</tr>
<tr>
<td>ISA Identification Letters</td>
<td>423</td>
</tr>
<tr>
<td>Dynamic scraped surface heat exchanger</td>
<td>392</td>
</tr>
<tr>
<td>Phase-change heat exchangers</td>
<td>392</td>
</tr>
<tr>
<td>Reboiler as seen on a distillation column</td>
<td>392</td>
</tr>
<tr>
<td>Heat Exchanger BTU Calculation and Control</td>
<td>393</td>
</tr>
<tr>
<td>Example of how to control the heat exchanger</td>
<td>393</td>
</tr>
<tr>
<td>Condenser (heat transfer)</td>
<td>394</td>
</tr>
<tr>
<td>Evaporation Processes</td>
<td>395</td>
</tr>
<tr>
<td>What is evaporation?</td>
<td>395</td>
</tr>
<tr>
<td>What is latent heat?</td>
<td>395</td>
</tr>
<tr>
<td>What is the boiling point?</td>
<td>395</td>
</tr>
<tr>
<td>Various Types of Evaporators and Their Working Principles</td>
<td>395</td>
</tr>
<tr>
<td>Vertical Falling Film Evaporator</td>
<td>395</td>
</tr>
<tr>
<td>Horizontal Film Evaporator</td>
<td>396</td>
</tr>
<tr>
<td>Low Temperature Vacuum Evaporator</td>
<td>397</td>
</tr>
<tr>
<td>Using the Psychrometric Chart</td>
<td>399</td>
</tr>
<tr>
<td>Cooling Towers</td>
<td>401</td>
</tr>
<tr>
<td>Cooling Tower Calculations</td>
<td>401</td>
</tr>
<tr>
<td>Cooling tower water loss and make-up</td>
<td>402</td>
</tr>
<tr>
<td>Cooling tower control scheme and operating cost</td>
<td>404</td>
</tr>
<tr>
<td>Typical pH correction system</td>
<td>405</td>
</tr>
<tr>
<td>Chemical Reactors and Control</td>
<td>406</td>
</tr>
<tr>
<td>What is a Reactor?</td>
<td>406</td>
</tr>
<tr>
<td>Types of Reactors</td>
<td>406</td>
</tr>
<tr>
<td>Basic Control Scheme for a Reactor</td>
<td>407</td>
</tr>
<tr>
<td>CSTR (Constant Stirred Tank Reactor)</td>
<td>407</td>
</tr>
<tr>
<td>Hydrocracking Reactor Controls</td>
<td>407</td>
</tr>
<tr>
<td>Chemical Scrubbers</td>
<td>408</td>
</tr>
<tr>
<td>Wet exhaust gas cleaning</td>
<td>408</td>
</tr>
<tr>
<td>Wet gas scrubber</td>
<td>409</td>
</tr>
<tr>
<td>Dry scrubbing</td>
<td>410</td>
</tr>
<tr>
<td>Scrubber waste products</td>
<td>410</td>
</tr>
<tr>
<td>Bacteria spread</td>
<td>410</td>
</tr>
<tr>
<td>Dehydration Processes</td>
<td>411</td>
</tr>
<tr>
<td>Absorption</td>
<td>411</td>
</tr>
<tr>
<td>Joule-Thompson effect</td>
<td>413</td>
</tr>
<tr>
<td>Crystallization Technology</td>
<td>414</td>
</tr>
<tr>
<td>Static Crystallization</td>
<td>414</td>
</tr>
<tr>
<td>Falling Film Crystallization</td>
<td>416</td>
</tr>
<tr>
<td>Suspension Crystallization</td>
<td>416</td>
</tr>
<tr>
<td>Process flow diagram suspension crystallization</td>
<td>417</td>
</tr>
<tr>
<td>Freeze Concentration</td>
<td>417</td>
</tr>
<tr>
<td>Overview of a small crystallization plant to control</td>
<td>418</td>
</tr>
<tr>
<td>Flare and Vent Disposal Systems</td>
<td>418</td>
</tr>
<tr>
<td>Types of flares</td>
<td>418</td>
</tr>
<tr>
<td>Flare Control Systems</td>
<td>418</td>
</tr>
<tr>
<td>Quality Control Standards for Production of Products</td>
<td>419</td>
</tr>
<tr>
<td>ISA Standards for Documentation</td>
<td>421</td>
</tr>
<tr>
<td>ISA Instrument or Function Symbol</td>
<td>421</td>
</tr>
<tr>
<td>ISA Line Type Symbols</td>
<td>422</td>
</tr>
<tr>
<td>Standard Line Types</td>
<td>422</td>
</tr>
<tr>
<td>ISA Identification Letters</td>
<td>423</td>
</tr>
</tbody>
</table>
Overview of Safety Instrumented Systems ................................................................. 443
Overview of process safety and shutdown ................................................................ 443
SIS (Safety Instrumented Systems) ............................................................................... 443
Complying with IEC 61511 / ISA-84 ............................................................................ 443
Other codes related to SIS systems ............................................................................... 444
ISA and OSHA letter defining the requirements of the implementation of SIS systems 444
Initiating Events of Safety Instrumented Systems .......................................................... 445
Initiating Event .................................................................................................................. 445
Examples .......................................................................................................................... 445
External Events ............................................................................................................... 445
Equipment Failures ........................................................................................................ 445
Human Failures ............................................................................................................... 445
The difference between BPCS and SIS systems ............................................................ 446
IEC 61508 mandatory and guidelines ............................................................................ 447
SIF and SIL ....................................................................................................................... 448
Risk analysis and protection layers ................................................................................. 448
Designing a SIS System .................................................................................................... 449
SIL (Safety Integrity Level) – Unit for Functional Safety ................................................ 449
SFF – Safe Failure Fraction ............................................................................................ 450
Probability of Failures on Demand (PFD) ..................................................................... 451
Probability of Failures per Hour (PFH) .......................................................................... 451
SIL Capability and Safety System .................................................................................. 452
SIF (Safety Instrumented Function) ................................................................................ 453
A typical P&ID of the (SIF) Instrumentation ................................................................. 453
Voting or (Polling of the System) .................................................................................... 454
A typical voting system and its instrumentation for the above P&ID .............................................. 454
Types of Voting (X out of X) .............................................................................................................. 454
Voting Probabilities .......................................................................................................................... 455
The SIS calculations .......................................................................................................................... 455
Quantification of Reliability in almost absolute terms ......................................................................... 455
Failure Models – The Bathtub Curve .................................................................................................. 456
Reliability Laws .................................................................................................................................. 457
Improving the reliability of a measurement system ............................................................................. 457
Safety Integrity Level (SIL) and Availability ......................................................................................... 458
Sample of SIL Evaluation .................................................................................................................... 458
Acronyms ........................................................................................................................................... 458
Metrics used in the reliability engineering field involving SIS ............................................................ 459
  2. MTTR = Mean Time to Repair ................................................................................................... 459
  3. MTBF – Mean Time Between Failures ....................................................................................... 459
  4. Availability A(t) and Unavailability U(t) .................................................................................... 460
  5. Probability of Failure on Demand (PFDavg) and Periodic Test and Inspection ......................... 460
SIS Calculations - worked example ...................................................................................................... 462
  Calculating PFD (Probability of Failure on Demand) ..................................................................... 463
  Calculating MTTF (Mean Time to Failure) Based on Failure Rates ............................................... 463
  Calculating MTBF based on failures ............................................................................................... 463
SIS and SIL – worked examples .......................................................................................................... 464
  Example 1: Pump Failure Rate (FR) ............................................................................................ 464
  Example 2: MTBF over 10 years .................................................................................................... 464
  Example 3: PFD and Test Interval .................................................................................................. 465
Recommended SIS Study Material ......................................................................................................... 466
Excerpts from Process Safebook 1 – Rockwell Automation .................................................................... 466

Overview of NEC / NFPA and Other Codes ......................................................................................... 469
CFR (Federal Government) Public Safety Standards of the United States ........................................ 469
List of NFPA codes (be familiar with these codes) ............................................................................. 472
NFPA 70 – NEC (National Electrical Code) ............................................................................................ 472
Voltage Drop Calculations .................................................................................................................. 473
  Substitute specific resistance (k) for resistance (R) of wire ............................................................... 473
  Wire and cable sizing formulas for voltage drop ............................................................................... 473
Voltage drop calculations – worked examples ..................................................................................... 474
NEC Article 500 Explosion Proof Installations ..................................................................................... 476
Class I Hazardous Location NEC Article 501 .................................................................................. 476
  Class I Location Definition ............................................................................................................... 476
  Class I Division Definitions .............................................................................................................. 477
  Class I Group Definitions .................................................................................................................. 477
  Class I Temperature Definition ....................................................................................................... 478
Class II Hazardous Location NEC Article 502 .................................................................................. 478
  Class II Location Definition ............................................................................................................... 478
  Class II Division Definitions .............................................................................................................. 478
  Class II Group Definitions .................................................................................................................. 479
  Class II Temperature Class ............................................................................................................... 479
Class III Hazardous Location NEC Article 503 .................................................................................. 479
  Class III Location Definition ............................................................................................................... 479
  Class III Division Definitions .............................................................................................................. 479
  Class III Group Definitions .................................................................................................................. 480
Use of Zone Classifications ................................................................................................................. 480
  Classification Comparison (Zone/Division) for a Class I Location .................................................. 480
Putting It All Together ......................................................................................................................... 515

Determine Scope of Design ............................................................................................................... 530
Heat Tracing Systems ........................................................................................................................ 528
Instrument Air Supply and Pneumatic Tubing .................................................................................. 525
Choose the Wiring Method ............................................................................................................... 521
Distributing the Power and Control .................................................................................................. 519
Some Typical Large DCS Architectures .............................................................................................. 517
Define the Scope of the Plant ........................................................................................................... 515

NFPA 79 Industrial Machinery........................................................................................................... 509
Conductor sizing............................................................................................................................... 509
Conductor colors............................................................................................................................... 509
Pushbutton functions for color ........................................................................................................ 509
Colors for Machine Indicator Lights and Icons Table 10.3.2........................................................ 509
NFPA 496 Purged and Pressurized Systems ...................................................................................... 510
Overview of the NFPA 496 articles ................................................................................................. 510
Factors to consider (NFPA 496, Sec. 5-3)....................................................................................... 510
Location of the control room (NFPA 496, Secs. 5-3.1(c) and 5-3.2) ............................................. 510
Positive pressure air systems (NFPA 496, Sec. 5-4.1)..................................................................... 511
Type X equipment (NFPA 496, Sec. 5-4.4).................................................................................... 511
Type Y equipment (NFPA 496, Sec. 5-4.5).................................................................................... 511
Type Z equipment (NFPA 496, Sec. 5-4.5).................................................................................... 511
Examples of Purged and Pressurized Systems................................................................................. 512
Basic design of purged enclosures................................................................................................. 512
Basic design of purged buildings.................................................................................................... 513
40 CFR and EPA - LDAR .................................................................................................................. 514
The Clean Air Act (CAA).................................................................................................................. 514
What the Law Requires..................................................................................................................... 514

Putting It All Together......................................................................................................................... 515

Free Heat Tracing Software ......................................................................................................... 530
Electrical Scope .............................................................................................................................. 531
Instrumentation and Mechanical Scope ......................................................................................... 531
Design of Electrical Plans .............................................................................................................. 532
Sample of a possible design for the control network and communications in plant ................. 533
Temperature Measurement and Calibration

In the process industry, temperature measurements are typically made with thermocouples, RTDs (Resistance Temperature Detector) and industrial thermometers. Industrial thermometers are typically of the liquid (class I), vapor (class II), and gas (class III) type.

<table>
<thead>
<tr>
<th>Standard Thermocouple Configurations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single Grounded</td>
</tr>
<tr>
<td>Dual Grounded Unisolated</td>
</tr>
<tr>
<td>Single Ungrounded</td>
</tr>
<tr>
<td>Dual Ungrounded Unisolated</td>
</tr>
<tr>
<td>Dual Ungrounded Isolated</td>
</tr>
</tbody>
</table>

In plants there are five major types of thermocouple (TC) configurations used. They are shown to the left.

The first two thermocouples are welded or grounded, as shown, to the outside metal protective sheathing.

The bottom three thermocouples are ungrounded and should never touch the metal protective sheathing; otherwise they are shorted to ground.

<table>
<thead>
<tr>
<th>Most Popular Types Used in Process Plant Temperature Measurements</th>
</tr>
</thead>
<tbody>
<tr>
<td>J-Type</td>
</tr>
<tr>
<td>K-Type</td>
</tr>
<tr>
<td>E-Type</td>
</tr>
<tr>
<td>T-Type</td>
</tr>
</tbody>
</table>

The four major thermocouples used in the process industry for temperature measurement are: J-Type, E-Type, K-Type, and T-Type.

The red wire is always the negative wire with thermocouples.

Thermocouple terminal junction blocks should be made of the same material as the thermocouple wire that is being connected to terminal. This will prevent additional thermocouple (TC) junction points from being introduced in the temperature signal. Some companies use standard terminal strips, this can cause an error in the signal.

<table>
<thead>
<tr>
<th>Thermocouple Extension Wiring</th>
</tr>
</thead>
<tbody>
<tr>
<td>Thermocouples should be extended with thermocouple extension wire and thermocouple termination blocks, but can be extended with standard copper wire and standard terminal blocks. This is due to the fact that the voltages generated at the extension junctions almost cancel each other out with very little error. One side is positive (the color: yellow, white, purple, etc.) and the other side is negative (always red, except in some extension wires).</td>
</tr>
</tbody>
</table>
Thermocouple millivolt tables for the examination can be found in the Table A1 – Thermocouple Table (Type J) through Table A4 – Thermocouple Table (Type T) in the Appendix section of this guide.

### Thermocouple Makeup Material and Color Code

<table>
<thead>
<tr>
<th>TC Type</th>
<th>THEMOCOUPLE MATERIAL</th>
<th>RANGE FOR CALIB. DEG F</th>
<th>USEFUL RANGE DEF F</th>
<th>TC COLORS</th>
</tr>
</thead>
<tbody>
<tr>
<td>E</td>
<td>Chromel (+) Constantan (-)</td>
<td>-300 to 1830</td>
<td>200 to 1650</td>
<td>Purple Wire Jacket Purple (+) Red (-)</td>
</tr>
<tr>
<td>J</td>
<td>Iron (+) Constantan (-)</td>
<td>-320 to 1400</td>
<td>200 to 1400 (300 to 800)</td>
<td>Black Wire Jacket Black (+) Red (-)</td>
</tr>
<tr>
<td>K</td>
<td>Chromel (+) Alumel (-)</td>
<td>-310 to 250</td>
<td>200 to 2300</td>
<td>Yellow Wire Jacket Yellow (+) Red (-)</td>
</tr>
<tr>
<td>R</td>
<td>Platinum 13% Rhodium (+) Platinum (-)</td>
<td>0 to 3100</td>
<td>1600 to 2640</td>
<td>Green Wire Jacket Black (+) Red (-)</td>
</tr>
<tr>
<td>S</td>
<td>Platinum 10% Rhodium (+) Platinum (-)</td>
<td>0 to 3200</td>
<td>1800 to 2640</td>
<td>Green Wire Jacket Black (+) Red (-)</td>
</tr>
<tr>
<td>T</td>
<td>Copper (+) Constantan (-)</td>
<td>-300 to 750</td>
<td>-310 to 660</td>
<td>Blue Wire Jacket Blue (+) Red (-)</td>
</tr>
</tbody>
</table>
**Sample problem:** What is the Millivolt (mV) output of a Type “J” thermocouple at 218°F and referenced to a 32°F electronic ice bath?

Find the nearest temperature in *Table A1 - Thermocouple Table (Type J)* in the appendix of this guide.

The nearest temperature in the first column is 210. Look at the column headers at the bottom of the chart. Find the column header labeled 8. Follow the column up to the row with the 210 value. Where they meet is a total of 210°F + 8°F = (218°F).

Read the value of mV. The answer is: 5.45 mV

**Sample problem:** What is the Millivolt (mV) output of a Type “K” thermocouple at 672°F from the data given? Assume the thermocouple is linear.

Given:

- 670°F = 14.479 mV
- 672°F = mV
- 680°F = 14.713 mV

We will have to interpolate the mV value for the desired temperature as follows:

Interpolation:

\[
mV = \left[ \frac{\text{deg desired} - \text{deg lower value}}{\text{deg upper value} - \text{deg lower value}} \right] (\text{mV upper value} - \text{mV lower value}) + \text{mV lower value}
\]

Therefore the new mV for 672°F:

\[
14.526 = \left[ \frac{672 - 670}{680 - 670} \right] (14.713 - 14.479) + 14.479
\]

The mV at 672°F is 14.526 mV

This can be verified in *Table A2 – Thermocouple Table (Type K)* in the appendix.
The process control industry also uses RTDs (Resistance Temperature Detectors) for many applications, for example, when precise temperature measurement is needed, such as mass flow measurements or critical temperature measurements of motor bearings.

RTDs typically come in 10-ohm copper and 100-ohm platinum elements. Their resistance is typically very linear over the scale.

Resistance values for the examination can be found in the *Table A5 - Platinum 100 Ohm RTD Table in ohms*, in the appendix section of this guide.

**Typical wiring configurations and uses of RTDs**

<table>
<thead>
<tr>
<th>2-wire RTD</th>
<th>3-wire RTD</th>
<th>4-wire RTD</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image" alt="2-wire RTD diagram" /></td>
<td><img src="image" alt="3-wire RTD diagram" /></td>
<td><img src="image" alt="4-wire RTD diagram" /></td>
</tr>
</tbody>
</table>

Good for close applications, at the transmitter.  
Good for further distance applications. Remote from the transmitter.  
Best application and usually uses 20 mA driving current and a voltage measurement.

**RTD - worked examples**

**Sample problem**: A RTD is platinum and has a resistance of 100 ohms at a temperature of 32°F and an alpha (0.2178 ohms per °F). What is the resistance of the RTD at a temperature of 240°F?

Find the difference in the temperature first.  
240°F – 32°F = 208°F

Now find the resistance for the differential temperature:  
208°F * 0.2178 ohms/deg F = 45.3 ohms

Now we add the change in resistance to the resistance at 32°F:  
100 ohms + 45.3 = 145.3 ohms

Referring to *Table-A5. Platinum 100 Ohm RTD Table in ohms*, in the appendix. The resistance value for the RTD can be interpolated and found for a given temperature.
**Sample problem:** In the bridge circuit below, if \( R_1 \) and \( R_2 \) are 200 ohms and the RTD is at 60°F. What resistance should \( R_3 \) measure, to balance the circuit and give the meter a reading of 0 volts? The RTD is platinum and measures 100 ohms at 32°F with an alpha of 0.2178 ohms per °F.

![Bridge Circuit Diagram]

Find the difference in the temperature first. 60°F – 32°F = 28°F

Now find the resistance for the differential temperature:

\[
28°F \times 0.2178 \text{ ohms/°F} = 6.0984 \text{ ohms}
\]

Now we add the change in resistance to the resistance at 32°F:

100 ohms + 6.0984 = 106.0984 ohms

The resistor \( R_3 \) needs to be 106 ohms to balance the bridge and give 0 volts at the meter.

---

**Sample problem:** In the bridge circuit above, \( R_1 \) and \( R_2 \) are 200 ohms. \( R_3 \) is 150 ohms. The excite voltage to the bridge is 10 volts. If the meter is reading 0.4 volts (the positive is on the right side and the negative on the left side) what is the temperature at the RTD?

Find the voltage on the left side of the bridge. This is the voltage we will add to the meter voltage on the right side. We will use the voltage divider theorem to find the voltage across \( R_1 \).

\[
V_{R1} = \frac{R_1}{R_1 + R_2} (10V) = \frac{200}{200 + 200} (10V) = 5V
\]

This means the voltage across the RTD is 5.0V + 0.4V = 5.4 volts.

We will now use the voltage divider theorem to find the resistance of RTD.

\[
V_{RTD} = \frac{R_{RTD}}{R_{RTD} + R_{R3}} (10V) ; \quad 5.4V = \frac{R_{RTD}}{R_{RTD} + 150} (10V)
\]

Solving for \( R_{RTD} \):

\[
5.4 = \left( \frac{R_{RTD}}{R_{RTD} + 150} \right) 10
\]
\[
\frac{5.4}{10} = \left( \frac{R_{RTD}}{R_{RTD} + 150} \right)^{10}
\]

\[
0.54(R_{RTD} + 150) = \left( \frac{R_{RTD}}{R_{RTD} + 150} \right)(R_{RTD} + 150)
\]

\[
0.54(R_{RTD} + 150) = R_{RTD}
\]

\[
0.54R_{RTD} + 0.54(150) = R_{RTD}
\]

\[
0.54R_{RTD} + 81 = R_{RTD}
\]

\[
0.54R_{RTD} - 0.54R_{RTD} + 81 = R_{RTD} - 0.54R_{RTD}
\]

\[
81 = R_{RTD} - 0.54R_{RTD}
\]

\[
81 = (1 - 0.54)R_{RTD}
\]

\[
81 = (0.46)R_{RTD}
\]

\[
\frac{81}{0.46} = \frac{(0.46)R_{RTD}}{0.46}
\]

\[
176.087 = R_{RTD}
\]

We can prove that the 176.087 ohms for the RTD is correct by plugging the value into the voltage divider formula to find the 5.4 volts at the meter.

\[
V_{RTD} = \frac{176.087}{176.087 + 100} \times 10V = 5.4V
\]

We have the ohms of the RTD, now we can find the temperature.

100 ohms = 32°F,

So subtract the difference in ohms 176.087 – 100 = 76.087 ohms.

Divide the 76.087 ohms by the alpha 0.2178 ohms per °F.

\[
\frac{\circ F}{\text{deg } F} = \frac{76.087 \text{ ohms}}{0.2178 \text{ ohms}} = 349.34 \circ F
\]
Add the 32°F bias for 100 ohms to the 349.34°F for 76.087 ohms and we get:

\[
349.34°F + 32.00°F = 381.34°F.
\]
Typical RTD and thermocouple applications

A complete assembly with a 4-20 mA transmitter in an explosion proof housing

Sensor head (option with transmitter)

Measuring inlet

Extension tube

Thermowell

Process connection

Industrial RTD or Thermocouple with head
A straight and tapered thermowell is shown

Various Industrial Thermometers
Threaded for mounting in tanks and pipes
Pressure measurement and head pressure

Pressure is measured in typically two different forms. Pounds per square inch (psi) or in head pressure. Head pressure is measured in inches or feet of water column (H₂O).

Head pressure is independent of the tank’s height or area. The transmitter measures head pressure. Head pressure is the measure of the potential energy in the system. The transmitter measurement is from how high is the fluid falling. The distance the fluid falls indicates the force generated (F=ma). This is why the density of the fluid must be known to calibrate a pressure transmitter for a process, to obtain the fluid mass. The calibration process uses specific gravity (s.g.), the ratio of a known density of a fluid divided by the density of water (H₂O).

To illustrate these facts, we will start with one gallon of water. The gallon of water equals 231 cubic inches and weighs approximately 8.324 pounds at 60°F. Pressure is measured in PSI (pounds per square inch). Only one (1) square inch of area is needed to calculate the height of the water and the force it is excerpting. Remember force divided by area = pressure.

Stack 231 cubic inches of water on top of each other, to form a tall column of water, with a base of one (1) square inch. The column of water will be 231 inches tall. Divide the height of the column of water, 231 inches, by the weight of one (1) gallon of water, 8.324 pounds. The result will be 27.691 or 27.7 inches H₂O, of head pressure, equals one (1) PSI.

By knowing the specific gravity of the fluid to be measured, multiplied by the height of the tank in inches, an equivalent value in inches of water can be found. The transmitter can now be calibrated in inches of water, regardless of the fluid. If the tank’s fluid has a s.g. equal to 0.8 and a height of 100 inches tall, then the height in inches of H₂O will be:

(100” of fluid * 0.8 s.g. = 80” of H₂O).

Pressure transmitters are purchased in different sizes of measurement. They are in ranges of inches H₂O, psig (the “g” stands for gauge pressure) or psia (the “a” stands for absolute pressure). When the symbol psid (the “d” stands for differential pressure) is called for, a standard psig transmitter is used. Most industrial pressure transmitters are differential pressure transmitters. They act on differential forces applied to each side of the transmitter. The force is produced by the pressure in the system multiplied by the area of the diaphragm.
Differential pressure or differential head pressure is used to calibrate transmitters for pressure, level, flow and density measurements. The transmitter has a high side, marked with an H, and a low side, marked with a L. The low side will typically go to atmospheric pressure or to a fixed height wet leg measurement. The high side will typically go to the tank, where the varying height of fluid is to be measured. When calibrating an instrument remember: The low side is the negative scale, below zero, and the high side is the positive scale, above zero. The transmitter's sensor element is static in position or elevation and therefore the transmitter itself is always equal to zero elevation. This will be discussed in detail in the section on Level Measurement.

Transmitters can be purchased in ranges of 25 in. of H\(_2\)O, 250 in. of H\(_2\)O, 1000 in. of H\(_2\)O, 300 psi and 2000 psi.

**The formula for calibration is:**

\[(\text{high side inches } \times \text{s.g.}) - (\text{low side inches } \times \text{s.g.}) = \text{lower or upper range value.}\]

*Note: Gives LRV when empty or minimum and URV when full or maximum*

**Sample problem:** A pressure gauge is reading 25 p.s.g. It is attached to a tank filled with a fluid. The bottom of tank is 65 feet above the ground. The pressure gauge is 5 feet above the ground. The fluid has a specific gravity of (0.7 s.g.). What is the level of the fluid in the tank?

First convert the psi gauge measurement to feet of head measurement.

\[25 \text{ psi } \times 2.31 \text{ feet per psi} = 57.75 \text{ feet of H}_2\text{O}.\]

Next find the elevation of the bottom of tank in relation to the elevation of the pressure gauge. Tank bottom in feet – pressure gauge elevation in feet, equals the height in feet to the bottom of tank.

\[65 \text{ feet} - 5 \text{ feet} = 60 \text{ feet of head to bottom of the tank}.\]

*Note: Head is always measured in the standard of inches or feet of water column (WC / w.c.)*

Multiply the head between the bottom of the tank and the pressure gauge times the s.g. to get the head equal to H\(_2\)O.

\[60 \text{ feet of fluid } \times 0.7 \text{ s.g.} = 42 \text{ feet H}_2\text{O to bottom of tank from the pressure gauge}.\]

Next subtract (the height from the pressure gauge to the bottom of the tank in feet of H\(_2\)O), from (the total height of fluid in feet of in H\(_2\)O above the pressure gauge), to find (the height of the fluid in the tank in H\(_2\)O).

\[(57.75 \text{ feet of H}_2\text{O total head}) - (42 \text{ feet of H}_2\text{O below the tank}) = (\text{feet of fluid in H}_2\text{O in the tank}).\]

\[(57.75 \text{ feet total}) - (42 \text{ feet to bottom tank from the pressure gauge}) = 15.75 \text{ feet in H}_2\text{O in the tank}.\]

Next convert height in feet of H\(_2\)O to height of fluid with a specific gravity (s.g.) of 0.7:

\[15.75 \text{ feet of H}_2\text{O} / 0.7 \text{ s.g.} = 22.5 \text{ feet of total height of the fluid column in the tank}.\]
Pressure change in a pipe for a given flow rate

On the CSE examination you will be asked to correlate signals and measurements using Flow, Pressure and the Output in (4 mA to 20 mA) signals. A change in flow in a pipe will cause a change in the head pressure across the pipe and measurement element. If the flow decreases in the pipe the pressure in the pipe will increase at any point along the pipe.

If the flow rate increases, the pressure in the piping system decreases. If the flow rate decreases, the pressure in the piping system increases. This is because the total head of the system remains constant due to the head pressure developed by of the pump. The total energy head being endowed into the pump and piping system, remains constant. This can be seen with a pump at a constant speed and two pressure gauges, one at each end of the pipe and a hand valve at the end of the pipe.

\[ h_1F_1^2 = h_2F_2^2 \]
\[ h_1\left(\frac{F_1}{F_2}\right)^2 = h_2 \]

**Sample problem:** There is a flow rate of 300 gpm in a piping system. There is a pressure gauge reading 100 psi somewhere in the piping system. If the flow rate is decreased to 240 gpm. What is the new pressure gauge reading in psi in the piping system?

Find the new pressure at the point of the gauge in the piping system for a flow rate of 240 gpm.

\[ h_2 = h_1\left(\frac{F_1}{F_2}\right)^2 = 100\left(\frac{300}{240}\right)^2 = 156.25 \text{ psi} \]

Pressure change across the flow element for a given flow rate

If the flow in the pipe increases, the head pressure on the outlet of the measurement element will decrease. This correlation can be demonstrated by the following equations for differential head pressure (\(\triangle P\)) across the orifice element (a fixed resistor) or smaller section of pipe (venturi or dall tube). See the section on *applications of basic fluid mechanics in process control.*

\[ h_1F_1^2 = h_2F_2^2 \]
\[ h_1\left(\frac{F_2}{F_1}\right)^2 = h_2 \]

**Sample problem:**

a) A flow of 250 gpm has a head pressure measurement of 309 inches of H\(_2\)O. If the flow is decreased to 150 gpm, what is the new head pressure (\(\triangle P\)) in H\(_2\)O for the measurement element?

b) What would be the new output to the PLC or DCS, in a mA signal, if the transmitter was calibrated in 0 to 400 inches of H\(_2\)O? The signal is calibrated for 4 mA to 20 mA.

**Answer:**
a) Find the new head pressure for 150 gpm.
\[ h_2 = h_1 \left( \frac{F_2}{F_1} \right)^2; \quad 309 \left( \frac{150}{250} \right)^2 = 111.24 \text{ in } H_2O \]

b) Find the mA output:

The output signal is the square root of the ratio of change in head pressure (new measurement) to the full scale calibrated range of the transmitter. First find the \% of head pressure in the scale of 0 to 400 inches H_2O.

\[ \% \text{ head} = \frac{111.24}{400} = 0.2781 \]

The output is a 4 mA to 20 mA current signal. The span is 16 mA (20 mA – bias of 4 mA)

Since the flow rate is a squared function, we must first extract the square root of the \% measurement to find the \% of output signal.

\[ \text{output mA} = \sqrt{0.2781} \times 16 \text{ mA} + 4 \text{ mA bias} = 12.44 \text{ mA} \]

---

**Pressure calibration of transmitter**

**Sample problem:** The pressure in a pipe is to be measured. The maximum pressure is measured as 462 feet of head of natural gas. It is to be displayed in units of psig. What is the calibration of the transmitter to display this pressure in 0 to 100\% psig on the display? The minimum pressure measurement will be zero feet of head?

Find the psig for the given maximum head pressure:

\[ \text{psig} = \frac{\text{feet head}}{2.31 \text{ psig per foot of head}} \]

Maximum measurement in psig:

200 psig = \(\frac{462}{2.31}\)

Next find the calibration range to order the transmitter:

The formula for calibration is:

(high side psi) \(\) – (low side psi) = lower or upper range value.

Note: Gives lower range value when minimum and upper range value when maximum

\[ \text{LRV} = 200 - 0 = 200 \text{ psi} \]
\[ \text{URV} = 0 - 0 = 0 \text{ psi} \]

The transmitter will be calibrated as:

0 to 200 psig
The calibration procedure below is as follows.

The level in a vessel or tank can be measured by a number of methods: differential pressure; displacement of volume; bubbler tube; capacitance; sonar; radar; weight, to name a few. This book will focus on differential pressure, displacement of volume, and bubbler tube for the examination.

REMEMBER: \((\text{high side inches} \times \text{s.g.}) - (\text{low side inches} \times \text{s.g.}) = \text{lower or upper range value.}\)

**See Example 1.**

The low side of the transmitter is open to atmosphere. Atmospheric pressure is pushing on the low side. The high side of the transmitter is connected to the tank; it also has atmospheric pressure pushing on it. The atmospheric pressures on each side of the transmitter cancel out. In the example, the first line of math will be the LRV and the second line of math will be the URV. The tank has 100 inches of fluid with a s.g. of 1.0. The calibrated Range of the instrument will be 0” to 100” of water or H₂O.

The \textit{Span} of the transmitter is: \((100” \times 1.0 = 100”)\)

**See Example 2.**

The low side of the transmitter is open to atmosphere. Atmospheric pressure is pushing on the low side. The high side of the transmitter is connected to the tank; it also has atmospheric pressure pushing on it. The atmospheric pressures on each side of the transmitter cancel out. In the example, the first line of math will be the LRV and the second line of math will be the URV.

The tank has a 100-inch level and the tube dropping down below the tank adds 20” of fluid height, with a s.g. of 1.0. The calibrated Range of the instrument will be 20” to 120” of water or H₂O. Remember the minimum measurement cannot be lower than the fixed tube height of 20”. Suppress the zero with the hard wire jumper or set the variable in the transmitter and make 20” a live zero for the instrument. In pneumatic instruments a suppression kit must be installed. The \textit{Span} of the transmitter is: \((100” \times 1.0 = 100”)\)
### Example 1: Open Tank Zero-Based Level Application

| Tank Level = 0 to 100 inches | s.g. = 1.0 |
|-----------------------------|
| (switch jumper to normal zero) |

![Diagram of Tank Level](image)

**LRV** = \((0\,\text{in} \times 1.0) - (0\,\text{in} \times 1.0)\) = 0\,\text{in} = 4\,\text{mA}

**URV** = \((100\,\text{in} \times 1.0) - (0\,\text{in} \times 1.0)\) = 100\,\text{in} = 20\,\text{mA}

Calibrate range from 0\,\text{in} to 100\,\text{in} \text{H}_2\text{O}

### Example 2: Open Tank Suppress the Zero

| Tank Level = 0 to 100 inches | s.g. = 1.0 |
|-----------------------------|
| (switch jumper to suppress zero) |

![Diagram of Tank Level](image)

**LRV** = \((20\,\text{in} \times 1.0) - (0\,\text{in} \times 1.0)\) = 20\,\text{in} = 4\,\text{mA}

**URV** = \((120\,\text{in} \times 1.0) - (0\,\text{in} \times 1.0)\) = 120\,\text{in} = 20\,\text{mA}

Calibrate range from 20\,\text{in} to 120\,\text{in} \text{H}_2\text{O}

---

See Example 3.

The low side is connected to the top of the closed tank. The high side is connected to the bottom of the closed tank. The tank’s pressure does not matter, because the pressures in low and high side lines cancel each other out. Since the tank is pressurized, a “wet leg” or “reference leg” must be used. This is the piping going from the low side of the transmitter to the top of the tank. It will be typically filled with some other type of product, such as glycol or silicon. This prevents moisture from accumulating in the line.

If moisture accumulates in the line, it will give an error in the transmitter reading. The wet leg has 100 inches of fluid with a s.g. of 1.1. In the example, the first line of math will be the LRV and the second line of math will be the URV. The tank has 100 inches of fluid with a s.g. of 1.0. The calibrated range of the instrument will be \(-110\,\text{in}\) to \(-10\,\text{in}\) of water or \text{H}_2\text{O}. **Elevate the zero** in the transmitter with the hard wire jumper or set the variable in the transmitter and make \(-110\,\text{in}\) a live zero for the instrument. In pneumatic instruments a suppression kit must be installed.

The Span of the transmitter is: \((100\,\text{in} \times 1.0 = 100\,\text{in})\)

See Example 4.

The low side is connected to the top of the closed tank. The high side is connected to the bottom of the closed tank. The tank’s pressure does not matter, because the pressures in the low and high lines cancel each other out. The wet leg has 120 inches of fluid with a s.g. of 1.1. The first line of math will be the LRV and the second line of math will be the URV. The tank has 100 inches of fluid and the tube dropping down below the tank adds 20\,\text{in}\ of fluid height with a s.g. of 0.8. The calibrated **Range** of the instrument will be \(-116\,\text{in}\) to \(-36\,\text{in}\) of water or \text{H}_2\text{O}. Remember the minimum measurement cannot be lower than 20\,\text{in}\ on the high side, due to the fixed 20\,\text{in}\ height of the tube dropping below the tank. **Elevate the zero** and make \(-116\,\text{in}\) a live zero.

The **Span** of the transmitter is: \((100\,\text{in} \times 0.8 = 80\,\text{in})\).

REMEMBER: \((\text{high side inches} \times \text{s.g.}) - (\text{low side inches} \times \text{s.g.}) = \text{lower or upper range value.}\)

*Note: Gives lower range value (LRV) when empty and upper range value (URV) when full.*
Example 3: Closed Tank
Elevate the Zero

Tank Level = 0 to 100 inches
s.g. = 1.0, Wet Leg: s.g. = 1.1
Height = 100"
(switch jumper to elevate zero)

![Diagram of tank level with S.G. = 1.1](image)

LRV = (0” x 1.0) – (100” x 1.1) = -110” = 4 mA
URV = (100” x 1.0) – (100” x 1.1) = -10” = 20 mA
Calibrate range from -110” to -10” H2O

Example 4: Closed Tank
Elevate the Zero (transmitter below tank)

Tank Level = 0 to 100 inches
s.g. = 0.8, Wet Leg: s.g. = 1.1
Height = 120"
(switch jumper to elevate zero)

![Diagram of tank level with S.G. = 0.8](image)

LRV = (20” x 0.8) – (120” x 1.1) = -116” = 4 mA
URV = (120” x 0.8) – (120” x 1.1) = -36” = 20 mA
Calibrate range from -116” to -36” H2O

---

Rosemount transmitters with seal for density and level applications

Rosemount suggested mounting with Wet/Dry Leg to prevent freezing

Running the low side tubing past the low side transmitter connection will prevent moisture build up.

Moisture collection pot

Approx. 30° slope with 2 ft (0.6 m) tubing, then up 1 ft (0.3 m)
The displacer tube for liquid level measurement is based on Archimedes principle that, the buoyancy force exerted on a sealed body immersed in a liquid is equal to the weight of the liquid displaced.

There are two types of displacer transmitters in common use today: torque tube and spring operated.

\[ f = \frac{V_{d,f}}{231} (8.338)G_f \]

Where:

- \( f \) = buoyancy force in lbf
- \( V_{d,f} \) = total volume of displaced process fluid in cubic inches
- \( L_s \) = the submerged length of the displacer in process fluid
- 231 = cubic inches in one gallon of water
- 8.338 = weight of one gallon of water in pounds
- \( G_f \) = specific gravity of displaced process fluid

**Sample problem:**

a) What is the force upward on the 30” displacer, if the displacer is 4” in diameter and submerged 10” in a fluid, with a specific gravity of 0.72?

\[ V_{d,f} = \left( \frac{\pi \times D^2}{4} \right) \times L_s = \left( \frac{\pi \times 16}{4} \right) \times 10 = 125.66 \text{ in}^3 \]

Find displacement force upward

\[ f = \frac{V_{d,f}}{231} (8.338)G_f = \frac{125.66}{231} (8.338)(0.72) = 3.266 \text{ lbf} \]

b) What is the mA output and percent output of the process signal?

Answer:

a) Find displaced volume:

\[ V_{d,f} = \left( \frac{\pi \times D^2}{4} \right) \times L_s = \left( \frac{\pi \times 16}{4} \right) \times 30 = 376.99 \text{ in}^3 \]

Find displacement force upward

\[ f = \frac{V_{d,f}}{231} (8.338)G_f = \frac{376.99}{231} (8.33)(0.72) = 9.798 \text{ lbf} \]
Find the % output and mA:

\[ \% = \frac{3.26}{9.79} = 0.333 \times 100 = 33.3\% \text{ output} \]

\[ (0.333 \times 16mA) + 4mA = 9.328mA \text{ output} \]

Various types of displacement measuring devices and transmitters
Bubbler level measurement

The bubbler tube or dip tube measures the level of the process fluid by measuring the back pressure on the bottom of the tube. This back pressure is the force exerted from the weight of the fluid in the tank against the tube opening. The tube will have to build up enough pressure for the gas to escape through the process fluid above the opening. The dip tube will have a static back pressure equal to the height or head of the process fluid above the bottom of the opening, as the bubbles escape the dip tube.

This simple level measurement has a dip tube installed with the open end close to the bottom of the process vessel. The lowest level that can be measured is from the bottom of the tank to the bottom of the dip tube. If the bottom of the dip tube is 2 inches of the bottom, the minimum level that can be measured is 2 inches. The maximum height that can be measured is only limited to the air supply pressure minus the minimum measurable level.

A flow of gas, usually air or nitrogen, is passed through a regulator to reduce the pressure. Then the flow of the gas will be controlled and monitored by passing through a rotameter (flow meter). It then makes its way down the dip tube and the resultant backpressure, due to the hydraulic head of the process fluid, forces back on the pressure transmitter. The pressure in the bubbler tube or dip tube equals the head pressure of level of the fluid in the vessel and a proportional signal is sent to the PLC or DCS. With a transmitter standard level calibration in inches of water, the signal output will vary proportionally with the change in level of the process fluid.

Sample problem: a) What is the head pressure measurement of a bubbler tube submerged 24” in a fluid with a specific gravity (s.g.) of 0.85?

b) What is the percent output and mA output, if the transmitter is calibrated for a tube 100” long and the transmitter is calibrated 0 to 85 inches H₂O (100 inches * 0.85 s.g. = 85 inches H₂O)?

Answer:

a) Find the head pressure of the process fluid

\[ h = L_{DipTube} G_f = 24 \times 0.85 = 20.4 \text{ inches H}_2\text{O} \]

(the water only excerpts a force of 20.4 inches H₂O against the bottom of the tube)

b) Find percent and mA output

The transmitter is calibrated for 0 to 85 inches H₂O which equals 0% to 100%

\[ \% = \frac{20.4}{85} = 0.24 \times 100\% = 24\% \text{ output} \]

The transmitter output is a 4mA to 20 mA current signal. The span is 16 mA (20 mA – bias of 4 mA) (0.24 * 16 mA) + 4 mA (bias) = 7.84 mA output, which equals 24% of the input measurement scale into the control room.

The control room computer (DCS or PLC) is scaling the input signal to value of 0 inches to 100 inches for the tank level. You can see 24% signal reads as 24 inches in the tank for the control room.
Density measurement

Head pressure and volume displacement can be used to measure density. By using a differential head pressure transmitter, calibrated in inches of water, connect the high and low lines to the tank at a fixed distance of separation, such as 10". Both taps of the density transmitter must be completely submerged below the top of fluid whose density is being measured. The height measured in inches of water divided by 10" (in our example), is the (s.g.) of the unknown fluid. Example: The density transmitter is measuring 7 inches H₂O, the s.g. = 0.7 (7”/10” = 0.7). See figure 2 below.

With the specific gravity (s.g.) known from the density transmitter, and a second level transmitter calibrated in inches of H₂O, the tank level can be found. The level measurement can be divided by the (s.g.) measurement from the density transmitter, to show the true height of the process fluid in the tank.

**Sample problem:** Find the density of the hydrocarbon product and the interface level of the water in the bottom of the tank in figure 2. The wet leg (sealed diaphragm leg) has a s.g. equal to 1.1

Remember: [(high side * s.g.) – (low side * s.g.)] = LRV or URV

**Density:**
- LRV = (0" * 1.0) – (10" * 1.1) = -11” H₂O (transmitter not covered with fluid or tank empty)
- URV = (10" * s.g.) – (10" * 1.1) = 7” H₂O (transmitter completely covered with process fluid)

URV = (10" * 0.825) – (10" * 1.1) = -2.75” H₂O (for Crude oil 40⁰ API)
- Find s.g. for crude oil 40⁰ API: [(-11) – (-2.75)] = 8.25” so… 8.25/10” = 0.825 s.g.
- URV = (10" * 0.7874) – (10" * 1.1) = -3.126” H₂O (for ethyl alcohol)
- Find s.g. for ethyl alcohol: [(-11) – (-3.126)] = 7.874” so… 7.874/10” = 0.7874 s.g.
- s.g. process signal = mA = [16 * 0.7874] + 4 = 16.5984mA or 78.74% signal.

**Level:**
- (% Level signal / % Density signal) * Tank Level = level of process fluid in the tank.

Note: The tank level measurement can be any height and the fluid to be measured of any density. Remember to elevate the zero on the density transmitter.

Using a bubbler arrangement to measure level with a varying density of process fluid:
Connect the high and low lines to the dip tubes as shown above in figure 1, at a fixed distance of separation in height, such as 2" or 10". We will use a 2" height differential between the bottoms of the tubes. The maximum distance above L1 equals 20” of process fluid.

**Sample problem:** Find the density and level in the tank in figure 1, using a bubbler arrangement.

**Density is calculated as**
- LRV = (0" * s.g.) – (0" * s.g.) = 0” H₂O (Density minimum, tank empty)
- URV = (0" * s.g.) – (2" * 1.0) = -2” H₂O (Density equals H₂O, L2 submersed and fluid at bottom of L1)
Remember to elevate the zero in the transmitter!

Since any level above L1 will cancel out in the density transmitter, the output is simply the percent signal which equals the s.g. of the process fluid.
Example: \(-2'' \times 0.7874 = -1.5748''\) H\(_2\)O (for ethyl alcohol) \(-1.5748''/-2'' = \text{s.g.} = 0.7874\) or 78.74% signal.

**Level is calculated as:**
For a 15'' level of ethyl alcohol above L1:

\[
\% \text{mA} = (15'' \times \text{s.g.}) = 11.811''\) H\(_2\)O = (11.811'' level)/(20'' max level) = 0.59055 or 59.055% signal
\]

At DCS/PLC the display will show Level/Density = 59.055/78.74 = 0.75 or 75% level.

Level = 0.75 \times 20'' = 15'' level

---

**Interface level measurement**

The combined level of the fluids in the tank must be above the top tap of the level transmitter connected to the tank. The distance “h” is the height between the high and low side taps and must be at a known constant distance. We want the lower tap (high side) to see the difference in height in the higher specific gravity fluid in the bottom of the tank, minus the lower specific gravity fluid in the top of the tank. Say we are trying to measure the level of water in a tank holding a hydrocarbon product.

If we know the s.g. of the hydrocarbon, we can calibrate the transmitter to an output of zero % signal, due to cancellation of forces (pressure \times area) on both sides. Then when the heavier water product enters the tank we can measure this extra weight by the force it is exerting on the transmitter in inches of water for an interface height. If we do not know the density of the hydrocarbon product, we will do what we did in the previous examples for finding the density of a fluid in a tank. We will put the density transmitter on the upper fluid level and then divide the bottom level measurement by the density multiplier.

If the wet leg and the lighter hydrocarbon product in the tank are the same fluid, the two levels (or forces) will cancel each other out when there is no water in the tank. *(The s.g. of the hydrocarbon product must be known and consistent, otherwise a density transmitter should be used to perform the level calculation for accuracy).*

The height in H\(_2\)O in the tank = [(height of H\(_2\)O) + (height of the lighter fluid * s.g.)]

The height in H\(_2\)O in the wet leg = (height of the lighter fluid in the wet leg * s.g.)

The signal height in inches of H\(_2\)O from the transmitter = [(height of H\(_2\)O) + (height of the lighter fluid * s.g.)] - (height of wet leg * s.g.) = measurement inches H\(_2\)O

**Sample problem:** Find the interface level in the tank.

The distance between taps is \(h = 100\) inches
Hydrocarbon s.g. = 0.7 (can be found from the density transmitter)
Water (H\(_2\)O) s.g. = 1.0
Maximum interface level to be measured = 50 inches (50% full)
First find the maximum level measurement in inches H₂O on each side of the transmitter:
The tank level (high side):
(50" H₂O) + (50" hydrocarbon * 0.7) = 50 + 35 = 85 in H₂O

The wet leg level (Low Side):
(100" hydrocarbon * 0.7) = 70 in H₂O

Max inches H₂O seen by the transmitter:
(high side) – (low side) = 85 – 70 = 15 in H₂O

Our transmitter will be calibrated to: 0" to 15" H₂O = 4 to 20 mA signal. We are at 50% full, therefore 100% transmitter signal or 20 mA. At 20 mA the DCS or PLC will see 100% input. We will convert that signal to the actual height of water in the tank.

Find the difference of s.g. of the two fluids:
1.0 s.g. (H₂O) – 0.7 s.g. (hydrocarbon) = 0.3 = 30%

Proof it works:
The transmitter is measuring 3.75 in H₂O.
Percentage of measurement = (measured inches by transmitter) / (full scale measurement or span).
This equals 3.75'/15' = 0.25 or 25% signal.
25% signal means the tank should have 12.5 inches of water in the bottom of the tank.

(measured inches H₂O by transmitter) / (difference in specific gravities) = Actual height of tank water.

Transmitter calculation:
(high side): (12.5" H₂O) + (87.5" hydro * 0.7) = 12.5 + 61.25 = 73.75 in H₂O
(low side): (100" * 0.7) = 70 in H₂O
(high side) – (low side) = 73.75 – 70 = 3.75 in H₂O

3.75" at the transmitter = 25% of signal = 3.75'/0.3 Δs.g. = 12.5" of water in the tank.
25% of the maximum allowable level of 50" in the tank would equal 12.5" of water.

Application Hint: The analog signal will be 25% or 8 mA. If we were using a 14-bit analog input card, the bit count would be 2¹⁴ or 16384 bits or steps. 16384 bits / 20 mA = 819.2 bits per mA. We need to subtract our bias of 4 mA, so 4 mA * 819.2 bits = 3276.8 or 3277 bits.

We subtract to get the full scale bit count: 16384 bits – 3277 bits = 13107 bits = 100% or full scale. 100% span equals 13107 bits to the PLC or DCS. The bits will be scaled in the PLC to floating point.

Bits for level: 25% signal = 0.25 * 13107 = 3276.75 or 3277 bits input signal.
3277 bits (signal) / 13107 bits (full scale) = 0.250019 (the PLC scaled register value)

Bits for density: 70% signal = 0.7 * 13107 = 9174.9 or 9175 bits.
Remember we want the difference of the specific gravities so: 1.0-0.7 = 13107 – 9175 = 3932 bits. A s.g. = (3932 bits / 13107 bits) = 0.29999237 (the PLC scaled register value)

Water interface height in inches = transmitter measurement height in inches / delta density.

[0.250019(% level signal from transmitter) * 15 inches(full scale measurement)] / 0.29999237(Δ s.g.) = 12.50127 inches water in the tank.
Radar and Ultrasonic level measurement

Time of flight technology

Time of flight devices are much newer technology than hydrostatic devices and consist of ultrasonic and radar devices (non-contact and guided wave). Radar is an acronym for Radio Detection and Ranging. Radar devices used for level measurement operate with electromagnetic radiation at wavelengths of 1.5 to 26 gigahertz. They are commonly known as microwaves. Non-contact radar and guide wave radar operate using the same principle.

Ultrasonic level measurement

Ultrasonic waves are not electromagnetic waves; they are mechanical sound waves. The speed at which mechanical waves travel is well known, about 1096 feet per second (334 meters/second) through air at 68°F. The level of the media can be determined by measuring the amount of time it takes for the ultrasonic wave to travel to the liquid, reflect and travel back to the device.

Most ultrasonic transmitters and receivers operate from 10 KHz to 70 KHz, well above the frequency of audible sound waves. In order for ultrasonic waves to be reflected, they need a media with a certain mass (density). In level measuring applications, there must be enough mass in the media (density) to reflect the sound waves.

Equations: \( L = E - D \) and \( D = C \times T/2 \)
- \( L \) = media level
- \( E \) = distance from measuring device to zero level
- \( D \) = distance from measuring device to media
- \( C \) = speed of sound or speed of light
- \( T \) = amount of time for sound or light to travel from device to liquid and back

Based on the figure to the right the level of media can be determined from the time it takes for sound waves or electromagnetic waves to travel from the measuring device to the media and back to the measuring device.

Advantages
- Accuracy independent of density changes, dielectric or conductivity
- No calibration with medium required
- Some come with SIL 2 and 3 ratings

Disadvantages
- Minimum density required
- Foam is an issue
- False measurements with turbulent surfaces
- No vacuum (10 psia), no high pressures (44 psia)

Radar (non-contact)

Non-contact radar devices use microwaves in the 6 to 26 gigahertz range to measure liquid level in tanks. Like the speed of sound, the speed of light (electromagnetic radiation) is well known, 186,000 miles per second. Based on equations 1 and 2 above, the level can be calculated by knowing the dimensions of the tank and measuring the amount of time it takes for the microwaves to reflect off the process media.

Why do radar level devices use microwaves compared to other types of energy in the electromagnetic spectrum? Microwaves have little effect from type of gases, temperature, pressure, buildup and condensate. However, the ability for the process medium to reflect or not reflect microwaves needs to be taken into account. You can determine this ability to reflect light or microwaves by looking at the dielectric number of the media.
The dielectric number is a measure of the polarization power of an insulating material or how much charge can be stored in a type of material vs. air. Water has a dielectric number of 80 and is considered a great reflector of microwaves. Air has a dielectric number of 1 and is considered a poor reflector of microwaves. Aqueous mixtures tend to work well with radar due to the high dielectric number.

However, while hydrocarbon based liquids can be measured, the measuring ranges may be lower due to lower dielectrics numbers. Petroleum oil has a dielectric number of 2 while gasoline has a dielectric number between 2 and 3. Because, ambient conditions have little effect on microwaves, radar devices are generally accepted as the most accurate level devices – some can measure level to ±0.5 mm or ±0.02 inches. This is one of the main reasons why suppliers, processors, and sellers of crude oil and other high-cost materials will use a radar device as part of their tank gauging equipment to accurately measure level.

Guided Wave Radar (GWR)

Guided wave radar devices use the same principle as non-contact radar devices – it has the ability to transmit and receive reflected microwave energy. Guided wave (sometimes called TDR – Time Domain Reflectometry) operates at 1.5 GHz. While the electronics are mostly the same as non-contact radar, the big difference is the wave guide. The wave guide is a metal rod or rope which guides the energy to the process media. See the image to the left. The wave guide directs approximately 80% of the available energy down the guide within an 8” radius.

GWR is suitable for a variety of level measurement applications including:

- **Unstable Process Conditions**
  - Changes in viscosity, density, or acidity do not affect accuracy

- **Agitated Surfaces**
  - Boiling surfaces, dust, foam, vapor do not effect device performance
  - Recirculating fluids, propeller mixers, aeration tanks

- **Extreme Operating limits**
  - GWR performs well under extreme temperatures up to 600°F (315°C)
  - Capable of withstandling pressures up to 580 PSIG (40 Bar)

- **Fine Powders and Sticky Fluids**
  - Paint, latex, animal fat and soy bean oil
  - Saw dust, carbon black, titanium tetrachloride, salt, grain
  - Oils or grease in tanks

Capacitance level measurement

Commercial capacitance level transmitters are proven devices and were first introduced in the 1950’s. They are also extremely versatile in that they can measure the continuous level and point level (a predetermined measurement point) of liquids, slurries, liquid-liquid interface as well as point level of solids. Capacitance technology for level devices has also become known as reactance, admittance or RF technology.

The capacitance calculation for empty and full is important because a minimum change of capacitance of about 10 pF is needed for measurement. Last but not least, foam can be tricky with capacitance probes. If the foam is conductive, the capacitance probe will see the liquid and the foam as the complete level. Capacitance transmitters and switches can come with SIL 2 and 3 ratings.
Radiometric (gamma) level measurement

Similar to radar devices, gamma level devices use electromagnetic radiation emitters and receivers to measure the level. Gamma devices can be used for liquids and solids in tanks. Gamma devices use electromagnetic radiation at a different part of the electromagnetic spectrum. They use gamma rays which have much higher frequency and therefore smaller wavelengths vs. microwaves.

A source of gamma radiation, usually Cesium 137 or Cobalt 60 depending on the application, is placed in a lead source container. The container can be closed (emitting no radiation) or open (emitting gamma radiation). A detector, capable of measuring the amount of radiation from the source, is installed on the other side of the tank. If the tank is empty, the detector receives most of the available gamma radiation. If the tank starts to be filled with liquid or solid, as the level increases, the media will attenuate (absorb) some of the available gamma radiation. When the tank is full, the detector receives very little radiation compared to the empty tank scenario.

This is an excellent level transmitter for difficult level measurements, such as catalyst levels in tanks that are in series with other tanks or the piping is in the way.

Gamma devices can also be used to measure the thickness of materials as well, not just levels. Gamma devices can also be used as Irradiators. Irradiators are devices or facilities that expose products to radiation to sterilize them, such as spices and some foods, milk containers, and hospital supplies.

Gamma level devices have been proven to be safe and reliable, if safety procedures and regulations are followed. The safety of personnel is number one and the amount of radiation over time that an employee can receive is well known and documented. All of this must be taken into account when purchasing gamma level devices. However, used safely, some of the most critical level measurements can be made with a gamma device.

Level gauging system in a tank farm
Calculating the volume in tanks

With a head pressure measurement, the height of the liquid in a tank can be measured. This is simple with standard cylindrical tanks, but much more difficult with irregular shaped tanks.

Calculating the volume in tanks will probably not be on the CSE exam, but the formulas to calculate the volume in these tanks is derived from calculus and included in the appendix of this guide. It will show how to calculate the volume of spherical tanks and bullet tanks, so the volume can be calculated in the PLC or DCS. See the section Calculating the Volume in Tanks for the volume formulas.

The tank ends can be flat (so the tank is just a horizontal cylinder). Tanks can come with different heads (end caps). They can be dished (ASME F&D, or Flanged & Dished), 2:1 elliptical or hemispherical.

TANK VOLUME CALCULATION

Horizontal Cylinder

\[
\left[ \left( \frac{D}{2} \right)^2 \cos^{-1} \left( \frac{D - h}{D} \right) - \left( \frac{D}{2} \right) \left( D - h \right)^{0.5} \right] L
\]

HEAD VOLUME CALCULATION

ASME F&D

\[0.215483 h^2 (1.5D - h)\]

Elliptical Head

\[\frac{\pi}{6} h^2 (1.5D - h)\]

Hemispherical Head

\[\frac{\pi}{3} h^2 (1.5D - h)\]

The liquid volumes in a horizontal cylinder, and ASME F&D, 2:1 elliptical and hemispherical heads are given by these equations. The (cos⁻¹) or (arccos) or (arcos) function must return radians, NOT degrees. In the appendix, the volume for the tank section plus both heads combine into one formula. These formulas can be modified using the formulas above for more accuracy with different heads (end caps).

The total volume of liquid in the tank is simply the liquid volume in the cylinder plus 2 times the liquid volume in the heads. (Hint: multiply tank diameter “D” x % level signal to get “h” (the height shown on the HMI or display), and then calculate the total tank volume with the math formula in the appendix.

81