2023
Gas Standards
Manual

This manual expires on December 31, 2023

FOREWORD

This manual is written to conform to the requirements of the United States Department of Transportation Pipeline Safety Regulations, 49 CFR, Part 191 and 192. It also, where necessary, identifies and references applicable state codes in Avista's operating territories.

The purpose of this manual is to set forth, in writing, Avista's policy pertaining to design, construction, operation, and maintenance of its natural gas systems. The Manager of Gas Engineering, a licensed Professional Engineer, should be the final signatory of designs that are completed by the Gas Engineering Department. The Avista mentioned herein refers to all states in Avista's operating territory. This manual supersedes any previous gas standards used by Avista gas companies prior to this date.

This manual is to be used in conjunction with the Gas Emergency and Service Handbook (GESH), Gas Construction Specifications, Manufacturer's Operating Instructions Manual for Gas Operations, Incident Prevention Manual (Safety Handbook), Transmission Integrity Management Program (TIMP), Gas Distribution Integrity Management Plan (DIMP), Anti-Drug and Alcohol Misuse Prevention Plan, Control Room Management Plan, Natural Gas Quality Assurance / Quality Control Program, and Public Awareness Program. These documents comprise Avista's Operating and Maintenance Plan as required by §192.605 and as required by state codes.

Operations Managers or personnel designated by them are responsible for adherence to these standards for proper installation and maintenance of Avista's natural gas facilities. This manual is made available to appropriate individuals through hardcopy, electronically, and/or via the company intranet per §192.615(b)(1)

Throughout this manual, material is referred to as approved type rather than by manufacturer's name or catalog number. Only materials approved by Gas Engineering or currently on record as suitable for purchase in the Supply Chain Management Department are to be used in the construction of company gas facilities.

Within the Gas Standards Manual a "shall" or "must" is used to indicate a provision is mandatory.

- Written variances to the Gas Standards Manual (for "shall/must" statements) may be granted except in situations where the provision is mandatory in state /federal code in which case the variance will not be granted.
- A request to not follow a "shall" or "must" starts with the respective local Avista manager/designated Avista representative giving their approval.
- The request will then be forwarded to the appropriate responsible reviewer as delineated in Specification 1.4, Table 1.
- These variances should be in written form (email preferred) and maintained with the as-built project documents.

Within the Gas Standards Manual a "should" is used to indicate that a provision is not mandatory but is the preferred method and recommended as a good practice.

- These "should" variances requested by Avista personnel do not require approval, but the documentation (typically within an as-built document) should explain why the "should" preferred method was not followed.

- “Should” variances requested by Avista contractors should be approved by the respective local Avista manager / local manager-designated Avista representative before implementing the variance. The variance grantor’s name and a reason why the “should” preferred method was not followed should be documented in the as-built document.

Responsibility for maintaining the accuracy of this manual is the function of the Gas Compliance Department. Suggestions for improvement are always welcome. Please forward suggestions or observations to Randy Bareither in the Gas Compliance Department via the “Recommended Changes” form from this manual or scan and send to him at Randy.Bareither@avistacorp.com.

Management Commitment and Support

Avista’s goal is to protect the health and safety of its employees and the communities in which we operate. Avista’s management is committed to supporting the Gas Standards Manual (GSM) and the corresponding activities which seek to recognize and mitigate threats to Avista’s pipeline facilities. Avista’s leadership provides this continuous support through the implementation of a Pipeline Safety Management System ((P)SMS.)

Avista’s (P)SMS provides an overarching safety strategy and framework designed to enhance the effectiveness of risk management and enable continuous improvement of pipeline safety performance. The GSM is evaluated and improved in accordance with the (P)SMS framework outlined in Avista’s Pipeline Safety Management Plan. Avista’s (P)SMS connects the GSM with the other plans, programs, and emergency response activities to ensure the continued safe operation of the gas system.

Pipeline Safety Management System

Avista’s (P)SMS is based on industry guidance provided in the American Petroleum Institute (API) Recommended Practice 1173 (RP 1173) “Pipeline Safety Management Systems.” RP 1173 details the components of a (P)SMS using 10 Essential Elements and the Plan, Do, Check, Act model (PDCA.) Avista has modified the model to replace the Act step with Adjust to align with our enterprise Safety Management system. The graphic below illustrates, each of the 10 Elements embedded into the PDCA circle showing the cyclical nature of PDCA and the continuous improvement philosophy of the (P)SMS. Each cycle through PDCA produces opportunities for improvement of our defenses and controls, making our system safer over time. The components of the Plan-Do-Check-Adjust cycle are as follows:

Plan: This step entails establishing the objectives and processes necessary to deliver results in accordance with the organization’s policies and the expected goals. By establishing output expectations, the completeness and accuracy of the process is also a part of the targeted improvement.

Do: This step is the execution of the plan designed in the previous step.

Check: This step entails the review of the results compared with established objectives. Comparing those results to the expected goals to ascertain any differences; looking for deviation in implementation from the plan.

Adjust: This step is where a pipeline operator takes actions to continuously improve process performance, including corrective actions on significant differences between actual and planned results, analyzes the differences to determine their root causes, and determines where to apply changes that will include improvement of the process or product.

Plan-Do-Check-Adjust Cycle

This manual or portions thereof should not be reproduced. If additional copies are required, please contact the Gas Compliance Department.

Jody Morehouse, PE
Director, Natural Gas

2023 UPDATES
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Date	Section No.	Category	Update
Jan 01, 2023	Foreword	Foreword	Language updated for clarification on “should” variances.
Jan 01,2023	1.1	Glossary – Automatic Shut-Off Valve (ASV)	Definition added.
Jan 01,2023	1.1	Glossary – Close Interval Survey	Definition added.
Jan 01,2023	1.1	Glossary – Composite Materials	Definition added.
Jan 01,2023	1.1	Glossary – Distribution Center	Definition rewritten to give additional clarification of the term “Distribution Center”.
Jan 01,2023	1.1	Glossary – Entirely Replaced Onshore Transmission Pipeline Segment	Definition added.
Jan 01,2023	1.1	Glossary – Field Investigation	Definition added.
Jan 01,2023	1.1	Glossary – Gathering Line	Definition added.
Jan 01,2023	1.1	Glossary – Incident Assessment	Definition added.
Jan 01,2023	1.1	Glossary – Notification of Potential Rupture	Definition added.
Jan 01,2023	1.1	Glossary – Odorization	Definition rewritten to give additional clarification of the term “Odorization”.
Jan 01,2023	1.1	Glossary – Rupture-Mitigation Valve (RMV)	Definition added.
Jan 01,2023	1.1	Glossary – Transmission Line	Definition rewritten to give additional clarification of the term “Transmission Line”.
Jan 01,2023	1.1	Glossary – Wrinkle Beds	Definition rewritten for clarification of the term “Wrinkle Bends”.
Jan 01,2023	1.3	Gas Acronyms and Abbreviations	Acronym “ELE” added for “Electric”
Jan 01,2023	1.3	Gas Acronyms and Abbreviations	Acronym “F/O” added for “Fiber Optic”
Jan 01,2023	1.3	Gas Acronyms and Abbreviations	Acronym “GPR” added for “Ground Penetrating Radar”

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Date	Section No.	Category	Update
Jan 01,2023	1.3	Gas Acronyms and Abbreviations	Acronym “HVAC” added for “High Voltage Alternating Current”
Jan 01,2023	1.3	Gas Acronyms and Abbreviations	Acronym “RMV” added for “Rupture Mitigation Valve”
Jan 01,2023	1.4	Table 1 – Standards Accountability	Specification 4.62 “Incident Assessment, Failure Assessment & Lessons Learned” added to table.
Jan 01,2023	2.12	Design Requirements – General	Document title “New Gas Material Evaluation Checklist” added to paragraph.
Jan 01,2023	2.12	Design Formula for Steel Pipe	Language in paragraph updated for clarification of SMYS of the pipe.
Jan 01,2023	2.13	Markings on Plastic Pipe Components	Bullet reference number updated.
Jan 01,2023	2.13	Tracer Wire	Language in paragraph updated for clarification of Specification titles.
Jan 01,2023	2.14	General – Steel Ball Valves	Language in paragraph updated for clarification of farm tap design.
Jan 01,2023	2.14	Transmission Line Valves	Paragraph added for additional clarification of requirements for RMV installation.
Jan 01,2023	2.14	Rupture Mitigation Valve (RMV) Requirements	Paragraph added for clarification of RMV requirements.
Jan 01, 2023	2.22	Meter Set Location, Protection, and Barricades	Paragraph rewritten to better define a “Remote Meter Set”.
Jan 01,2023	2.24	Appendix A Table	Drawing A-35208 revised.
Jan 01,2023	2.24	Appendix A Table	Drawing A-37102 revised.
Jan 01,2023	2.24	Appendix A Table	Drawing C-35209 revised. (Pages 1-2)
Jan 01,2023	2.24	Appendix A Table	Drawing B-33325 revised. (Pages 1,2, and 4)
Jan 01,2023	2.24	Appendix A Table	Drawing B-38205 revised.
Jan 01,2023	2.724	Appendix A Table	Drawing B-35785 revised.
Jan 01,2023	2.24	Appendix A Table	Drawing E-37197 revised.

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Date	Section No.	Category	Update
Jan 01,2023	2.24	Appendix A Table	Drawing E-37842 revised.
Jan 01,2023	2.24	Appendix A Table	Drawing E-37970 revised.
Jan 01,2023	2.24	Meter and Regulator Tables and Drawings	Fisher regulator HSR added multiple times throughout specification.
Jan 01,2023	2.24	Meter and Regulator Tables and Drawings – Obsolete Regulators	Fisher regulator S102 added to table.
Jan 01,2023	2.24	Meter and Regulator Tables and Drawings – Obsolete Regulators	Rockwell regulator 107 added to table.
Jan 01,2023	2.24	Meter and Regulator Tables and Drawings – Obsolete Regulators	Rockwell regulator 173 added to table
Jan 01,2023	2.24	Meter and Regulator Tables and Drawings	Paragraph added multiple times throughout specification, "**** Not acceptable because droop/boost would exceed design criteria. Replace with proper regulator or orifice if found in the field."
Jan 01,2023	3.12	Liquid Epoxy Coating	"…shall…" changed to "…can…"
Jan 01,2023	3.12	Abrasion Resistant Overlay Wrap	Subsection and paragraph were renamed and rewritten for clarification as Avista switched from "Stop it BoreShield ARO" to "Scar Guard"
Jan 01,2023	3.12	Installation in Ditch	Paragraph and bullet points added for clarification on backfill, and post installation procedures for transmission pipeline coating damage assessments.
Jan 01,2023	3.12	Marker Balls	Paragraph rewritten to include valves and stubs in the first sentence and clarification for installation of additional marker balls as applicable.
Jan 01,2023	3.12	Coating Thickness for New Pipe	Paragraph rewritten to meet new requirement in 192.461(a)(4)
Jan 01,2023	3.14	Pre-Construction Inspection	Paragraph updated for additional clarification of pipeline materials.

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Date	Section No.	Category	Update
Jan 01,2023	3.16	Excess Flow Valves	Paragraph bullet points rewritten to reflect PHMSA, EFV, FAQ.
Jan 01,2023	3.16	Excess Flow Valves	Table added for clarification of use of an EFV or curb valve.
Jan 01,2023	3.16	Insertion of Old Steel Services Along Plastic Main	Paragraph updates for clarification of the cadwelding process, prior to inserting plastic pipe.
Jan 01,2023	3.16	Service Lines to Floating Structures	Subsection and paragraph added for clarification of service lines being installed to floating structures.
Jan 01,2023	3.18	Recordkeeping	Pressure test information sticker example updated to match what is being used in the field.
Jan 01,2023	3.19	Future Locatability	Paragraph updated for clarification of what “extreme pipe depths” may be interpreted as.
Jan 01,2023	3.22	Retesting after Failure	Paragraph rewritten for clarification of when retesting can occur.
Jan 01,2023	3.23	Butt Fusion Procedures	“ENDOT” added multiple times throughout section.
Jan 01,2023	3.24	Electrofusion	“Jameson” added multiple times throughout section.
Jan 01,2023	3.24	General	Paragraph rewritten for clarification of how to verify clearances from previous squeeze points.
Jan 01,2023	3.25	General	Paragraph rewritten for clarification of how to verify clearances from previous squeeze points.
Jan 01,2023	3.32	Regulatory Requirements	Added, “§192.485” and “§192.712”
Jan 01,2023	3.32	Transmission Lines	Paragraph rewritten for clarification of repairs to transmission lines.
Jan 01,2023	3.32	Tables	Title changed to: “STEEL REPAIR SELECTION CHART FOR DISTRIBUTION PIPELINES WITH AN MAOP OF 500 PSI OR GREATER, REFER TO TRANSMISSION LINES SECTION ABOVE FOR TRANSMISSION REPAIRS”
Jan 01,2023	3.34	Squeezing Procedure	Bullet point 2, rewritten for clarification that squeeze clearances in this section must be visually confirmed.
Jan 01,2023	3.34	Squeezing Procedure	Notation and table added throughout document regarding PE pipe squeeze and release time when the temperature is at or below 32°F.

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Date	Section No.	Category	Update
Jan 01,2023	3.34	Post-Squeeze Procedure	Bullet point 3 rewritten to say: "Wrap black electrical tape around the pipe on both sides of the squeeze point and over the squeeze point in the shape of an "X" prior to backfilling."
Jan 01,2023	3.44	General	Added "…and any aboveground piping."
Jan 01,2023	4.11	Extreme Weather Event or Natural Disaster – Transmission Pipeline Facilities Inspection	Subsection and paragraph added for clarification of procedures following an extreme weather event or natural disaster that has potential to cause damage to **transmission** pipeline facilities.
Jan 01,2023	4.13	Public Awareness Program	Paragraph added for new information regarding OPUC Procedures Audit Checklist.
Jan 01,2023	4.13	Locating and Marking Avista Facilities	Added acronyms, "F/O" and "HP" to paragraph multiple times through subsection.
Jan 01,2023	4.13	Locating and Marking Avista Facilities	Bullet points rewritten for clarification of Polyethylene whiskers and Marking pin flags
Jan 01,2023	4.13	Locating and Marking Avista Facilities	Paragraph rewritten to clarify documentation requirements by locator.
Jan 01,2023	4.13	Hard to Locate Facilities – Additional Actions	Bullet point number 6, updated to include valves.
Jan 01,2023	4.13	APWA Uniform Color Codes for Marking	Color Code "RED" rewritten to include cathodic protection.
Jan 01,2023	4.13	Photograph Requirements	Bullet point rewritten to match current standard operating procedures.
Jan 01,2023	4.14	Multiple	Report due date of March 15th added to multiple WAC Codes.
Jan 01,2023	4.16	Regulatory Requirements	Regulatory Requirements added: §192.179, §192.610, §192.619, §192.636
Jan 01,2023	4.16	Change in Class Location	Paragraph added for clarification of class location changes to meet added regulatory requirements.
Jan 01, 2023	4.16	Documentation of MAOP Revisions	Paragraph rewritten for clarification of documentation and retention requirements.
Jan 01,2023	4.17	Prior to Pressure Increase	Paragraph was rewritten to match current standard operating procedures.

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Date	Section No.	Category	Update
Jan 01,2023	4.18	Odorant Concentrations	Paragraph rewritten for better clarification of procedure expectations.
Jan 01,2023	4.18	Locations Where Odor is Inadequate	Paragraph rewritten for better clarification of procedure expectations.
Jan 01,2023	4.31A	Multiple	Several OQ Task Descriptions have been updated to state task completion satisfies skills required for Recognizing Unsafe Meter Sets (221.070.070)
Jan 01,2023	4.31A	Recognizing Unsafe Meter Sets	Description rewritten for additional clarification of this OQ task.
Jan 01,2023	4.51	Regulatory Requirements	Regulatory Requirements added: §192.619, WAC 480-93-018, 480-93-180
Jan 01,2023	4.62	All	New Specification added to the GSM due to new federal rule requirements.
Jan 01,2023	5.10	Maintenance Matrix Table – Cathodic	"Atmospheric Corrosion, aboveground pipelines other than services", added.
Jan 01,2023	5.11	Gas Leak Detection Instruments	Subsection and paragraph renamed and rewritten to better define Leak Detection Instruments.
Jan 01,2023	5.11	Gas Leak Detection Instruments	DP-IR definition rewritten to better define the detection instrument.
Jan 01,2023	5.11	Gas Leak Detection Instruments	Laser Methane Detector, and various types of approved methane detectors added or updated in subsection.
Jan 01,2023	5.11	Gas Leak Detection Instruments	Combustible Gas Indicator (CGI) and various approved types of combustible gas indicators added or updated in the subsection.
Jan 01,2023	5.11	Gas Leak Detection Instruments	IRed Infrared Ethane Detector rewritten to be, "Sensit IRed Portable Infrared Ethane Detector (IRED)
Jan 01,2023	5.11	Gas Leak Detection Instruments	IRED paragraph rewritten for clarity and accuracy.
Jan 01,2023	5.11	Gas Leak Detection Instruments	Paragraph updated for previously utilized detectors reference.
Jan 01,2023	5.11	Surface Gas Detection Survey	Paragraph rewritten to match current standard operating procedures and align with GESH.
Jan 01,2023	5.11	Surface Gas Detection Survey	Foot Survey - Paragraph rewritten to address procedures for when facilities are not accessible by foot.

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Date	Section No.	Category	Update
Jan 01,2023	5.11	Surface Gas Detection Survey	Mobile Survey - Paragraph rewritten to add the words “or by boat”.
Jan 01,2023	5.11	Surface Gas Detection Survey	Diver or Remote Submersible Survey (Underwater) survey type and definition added.
Jan 01,2023	5.11	Surface Gas Detection Survey	Boat Survey (Overwater) survey type and definition added.
Jan 01,2023	5.11	Surface Gas Detection Survey	Survey Documentation & Follow Up subsection and definition added.
Jan 01,2023	5.11	Surface Gas Detection Survey	Survey Limitations subsection is now a subsection of the “Surface Gas Detection Survey” subsection, and was rewritten to better define the term “Survey Limitations”
Jan 01,2023	5.11	Soap/Bubble Leak Test	Subsection and paragraph rewritten to match current standard operating procedures.
Jan 01,2023	5.11	Multiple	“…and the environment.” Added several times throughout Specification 5.11.
Jan 01,2023	5.11	Can’t Gain Entry / Can’t Find	“…follow up order...” changed to “…service order…”
Jan 01,2023	5.11	Leak Survey Plans	“…program for the coming year.” Changed to “…program scope for the coming year.”
Jan 01,2023	5.11	Annual Distribution System Surveys	Subsection and paragraph rewritten for clarification of Annual Survey requirements.
Jan 01,2023	5.11	Identifying High Occupancy Structures, High Occupancy Areas, and Business Districts	Identifying High Occupancy Structures, High Occupancy Areas, and Business Districts is now a subsection of the “Annual Distribution System Surveys” subsection and was rewritten to better define the standard operating procedures used.
Jan 01,2023	5.11	Transmission and Other High Pressure Pipelines	Subsection and paragraph renamed and rewritten to better define, transmission and other high pressure pipelines.
Jan 01,2023	5.11	Transmission and Other High Pressure Pipelines	Subsection “250+ psig Pipelines Washington Only” is now a subsection of the “Transmission and Other High Pressure Pipelines” subsection and was rewritten to better define the standard operating procedures.
Jan 01,2023	5.11	5 Year Distribution System Surveys	Subsection and paragraph renamed and rewritten to better define, 5 year distribution system surveys.
Jan 01,2023	5.11	Special Surveys	Paragraph and bullet points rewritten for clarification of special survey requirements, and standard operating procedures.

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Date	Section No.	Category	Update
Jan 01,2023	5.11	Grade 2 Leak	Bullet point 6 rewritten to match current standard operating procedures.
Jan 01,2023	5.11	Grade 2 Leak – Action to Be Taken	Paragraph rewritten for clarity and accuracy.
Jan 01,2023	5.11	Underground Leak Determination	Subsection moved to be before subsection Investigation and Classification, for alignment with GESH.
Jan 01,2023	5.11	Underground Leak Investigation	Paragraph rewritten to provide reference, “Service Line Leak Survey” for further details.
Jan 01,2023	5.11	Pinpointing / Centering	Paragraph(s) rewritten to match current standard operating procedures.
Jan 01,2023	5.11	Service Line Leak Survey	Paragraph rewritten to align verbiage with GESH.
Jan 01,2023	5.11	Follow-up Inspections for Residual Gas	Paragraph rewritten to match current standard operating procedures.
Jan 01,2023	5.11	Leak Survey Forms	Additional approved instruments, RMLD, IRED, and CGI added to survey method
Jan 01,2023	5.11	Special information required for leaks discovered	“Map reference number” changed to “Leak Survey Map reference number”
Jan 01,2023	5.11	Special information required for leaks repaired	“Part of system (main, service)” changed to “System facility (main, service, valve, etc.)”
Jan 01,2023	5.11	Leak Failure Cause Definitions – Equipment	“ERT/degradation” changed to “ERT Leaking/degradation”
Jan 01,2023	5.11	Hazardous Mechanical Fitting Failures	“Dan Wisdom” changed to “Gas Materials Specialist”
Jan 01,2023	5.12	General Maintenance of all Service Pressures	“domestic” changed to “residential” in two instances
Jan 01,2023	5.12	General Maintenance of all Service Pressures	Added “up to” for line pressures to cover 10 psig 15 psig, 20 psig, etc.
Jan 01,2023	5.12	General Maintenance of all Service Pressures	Added “Periodic Meter Changeout” to paragraph.
Jan 01,2023	5.12	Maintenance of Elevated Service Pressure Accounts	Paragraph rewritten to combine 2 psig and 5 psig into one paragraph.

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Date	Section No.	Category	Update
Jan 01,2023	5.12	Maintenance of Industrial Meter Sets	"…considered…" changed to "…classified as…"
Jan 01,2023	5.12	District Regulator Stations	Paragraph updated to better define the term "District Regulator Station" with regard to master meter considerations.
Jan 01,2023	5.15	General	Reverted number of years in rotation from "5 year not to exceed 63 months" back to "3 years not to exceed 39 months". The previous change made in 2022 was in error.
Jan 01,2023	5.15	Methods of Patrolling	Added reference "5.11 Leak Survey".
Jan 01,2023	5.15	Pipeline Markers for Buried Pipe	Paragraph updated to match current standard operating procedures and/or code requirements.
Jan 01,2023	5.19	Corresponding Standards	Added, GESH 2, GESH 4, GESH 17.
Jan 01,2023	5.20	Inspection Requirements	Paragraphs updated to match current standard operating procedures and/or code requirements.
Jan 01,2023	5.20	Can't Gain Entry / Can't Find	Minor grammatical edits
Jan 01,2023	5.20	Remediation	Added "…or white…"
Jan 01,2023	5.20	Recordkeeping	Added "…or Jimmie Dean Center."

OPERATING AND MAINTENANCE PLAN
RECOMMENDED CHANGES

In adherence with 49 CFR 192.603 and 192.605 and Gas Standard Spec. 1.4, “Gas Operations and Maintenance Plans”, the following is a review of the existing Company O&M Plan for conducting operations, maintenance activities and emergency responses.

Manual Reviewed____Date____________________

Section ____

Title of procedure ____

Reviewed by / Submitted by____

Recommended changes (please fill out separate sheets for each recommended change):

Return to Randy Bareither, MSC 6
(randy.bareither@avistacorp.com)

FOR OFFICE USE:

Received Date ________________

Action Taken

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5.10 GAS MAINTENANCE TIMEFRAMES AND MATRIX

5.11 LEAK SURVEY

5.12 REGULATOR AND RELIEF INSPECTION

5.13 VALVE MAINTENANCE

5.17 REINSTATING ABANDONED GAS PIPELINES AND FACILITIES

5.18 VAULT MAINTENANCE

5.19 COMBUSTIBLE GAS INDICATOR TESTING AND CALIBRATION

5.20 ATMOSPHERIC CORROSION CONTROL

5.23 ODORIZATION EQUIPMENT

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DIAGRAMS, ILLUSTRATIONS AND FLOWCHARTS

GIS MAPPING SYMBOLOGY

- Bonded Dresser
- Bottom Out Line Stopper
- Coupling/Dresser
- End Cap or Stub
- Expansion Joint
- Extension Stopper
- Flange
- Split Tracer Wire PE
- Flanged Tee
- Dresser Insulated
- Flange Or Kerotest Insulated
- Line Stopper
- Reducer
- Side Out Stopper
- Transition
- Top Stopper
- Tapping Tee
- Tapping Tee w/ Excess Flow Valve
- High Volume Tee
- Inline Tee
- Elbow
- Clamp
- Undetermined Gas Stopper
- Insulating Joint/Zunt
- Excess Flow Valve
- Barreled Dresser
- Purge Fitting
- Inline Tee with EFV
- Reducer Inline Tee w/ EFV
- Reducer Coupling w/ EFV
- Anode Set
- Single Service
- Multiple Service
- Idle Riser
- Non-Metered Service

- Gas Marker Ball
- Test Point Container - With Inspections
- Test Point Container - No Inspections
- Test Point Container - Misc Location - Bridge Crossing
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- Test Point Container - Misc Location - Water Crossing
- Test Point Container - Misc Location - Non-Typical AC Inspection
- Rectifier
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- Regulator Station - District
- Regulator Station - City Gate
- Regulator Station - Single Service Farm Tap
- Regulator Station - Industrial Meterset
- Regulator Station - Master Meter
- Regulator Station - Odorizer
- Regulator Station - Unclassed
- Gas Leak/Repair
- Exposed Pipe
- Exposed Pipe/Gas Repair
- Gas Leak/Repair - Abandoned
- Exposed Pipe - Abandoned
- Exposed Pipe/Gas Repair - Abandoned
- Gas Leak/Repair - Unattached
- Exposed Pipe - Unattached
- Exposed Pipe/Gas Repair - Unattached
- Exposed Pipe - Pipe Data Out of Sync
- Exposed Pipe/Gas Repair - Pipe Data Out of Sync
- Invalid Usage, Installed Status, or Normal Status
- EOP or Emergency, Active, Closed
- EOP or Emergency, Active, Open
- EOP or Emergency, Disabled, Closed
- EOP or Emergency, Disabled, Open
- Secondary, Active, Closed
- Secondary, Active, Open
- Secondary, Disabled, Closed
- Secondary, Disabled, Open

<all other values>

Type

Critical Alarm

Noncritical Alarm

Pressure Recorder

Gas Warning sign

Barhole Location

Abandoned Gas Device

Eop Zone Pipe

Cathodic Zone

Ribbon Anode

Gas Event

Cathodic Conductor

HP Steel Pipe (Abandoned)

HP Plastic Pipe (Abandoned)

HP Vintage Plastic Pipe (Abandoned)

IP Steel Pipe (Abandoned)

IP Plastic Pipe (Abandoned)

IP Vintage Plastic Pipe (Abandoned)

HP Steel Pipe

HP Plastic Pipe

IP Steel Pipe

IP Plastic Pipe

IP Vintage Plastic Pipe

HP Steel Pipe in Conduit

HP Plastic Pipe in Conduit

IP Steel Pipe in Conduit

IP Plastic Pipe in Conduit

IP Vintage Plastic Pipe in Conduit

HP Steel Pipe in Casing

HP Plastic Pipe in Casing

IP Steel Pipe in Casing

IP Plastic Pipe in Casing

IP Vintage Plastic Pipe in Casing

Unknown Pipe

Dry Line

Unlocatable

Gas Empty Conduit

Gas Planning Proposals

SIZENUMBER

2"

4"

6"

>6"

Gas Planning AOI

Area Type

Critical Pressure

Low Pressure

Miscellaneous

New Developments

Gas Special Condition

Note Field Note

Problem Customer

Structure

Avista Owned

Foreign Owned

Temporary Structure

Shadow Structure

Move If Touched

Must Be Moved

1.1 GLOSSARY

ABANDONED PIPELINE: A pipeline permanently removed from service that has been physically separated from its source of gas or hazardous liquid and is no longer maintained under regulation 49 CFR Part 192, as applicable. Abandoned pipelines are usually purged of the gas and refilled with nitrogen, water, or a non-flammable slurry mixture.

ABNORMAL OPERATING CONDITIONS: A condition identified by the operator that may indicate a malfunction of a component deviation from normal operations that either indicates a condition exceeding design limits or results in a hazard to persons, property, or the environment.

ACCESS, SAFE: Condition of being reached safely and quickly for operation, inspection, adjustment, or repair without requiring climbing over or removing obstacles. Safe access may also be provided by use of an approved ladder.

AIR/FUEL RATIO: The proper combination of air and gas required for complete combustion. For natural gas, the ratio is 10 to 1 (10 parts air to 1 part gas). For propane, the corresponding ratio is 25 to 1. See also Explosive Limit.

AIR SHUTTER: An adjustable gate or door used to control the amount of primary air to an atmospheric style burner.

ALARM: An audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

ALCOVE: A recessed area within a building's exterior wall that is sealed from the building interior.

ALDEHYDES: Chemical compounds formed along with carbon monoxide during the incomplete combustion of natural gas. Aldehydes cause watering of the eyes and a burning feeling in the throat.

ALLOWABLE PRESSURE DROP (PRESSURE DROP): The maximum allowable loss in working pressure in a piping system, typically measured from the outlet of the gas meter to the furthest appliance.

AMPERE (AMP): The unit of measurement of electric current proportional to the quantity of electrons flowing through a conductor past a given point in one second.

ANODE (Cathodic Protection): The expendable material, which is buried and through which direct current flows into the soil. Common materials used for this purpose are graphite or carbon rods, silicon, iron, magnesium, zinc, and scrap iron.

ANODE (Corrosion): The electrode of a corrosion cell which has the greater tendency to corrode or oxidize.

ANODE EFFICIENCY: The ratio of the actual corrosion of an anode to the theoretical corrosion calculated from the quantity of electricity, which has passed.

ANODELESS RISER: A plastic pipe sheathed inside a protective steel metallic casing. The steel-cased plastic pipe protrudes from the soil and is part of the service line carrying gas to the customer meter. An anode is not required in this instance because the plastic pipe contains the gas pressure and is not susceptible to the typical corrosive processes.

ANODIC FIELD: The area in which the soil potential is raised because of current flow away from a ground electrode (anode). The extent of this influence is a function of soil resistivity and the magnitude of current flow.

APPLIANCE: A device which uses fuel or other forms of energy to produce light, heat, power, refrigeration, or air conditioning. This definition shall also include vented decorative appliances. This definition is also used interchangeably with the term "equipment" in this policy.

APPLIANCE REGULATOR: A control device installed on an appliance fuel line to reduce house line gas pressure to the required appliance manifold pressure.

APPROVED: Materials, equipment, appliances, methods of inspection, or construction that are approved as a result of tests, standards, or investigations by the authority having jurisdiction or by national authorities or testing bodies. The Company may also provide direction in this respect as indicated in the Operating and Maintenance plan. The approval which is most restrictive shall prevail in cases where there is a difference between Company policy and other accepted or required standards.

APPURTENANCE: Any attachment to or component of a pipeline that may be subjected to system pressures including (but not limited to), pipe, valves, fittings, flanges, and closures.

AREA ODOR: An odor or smell located in a general area that is thought to be natural gas, but that may also be the result of other chemicals or actions in a given area.

ASSESSMENT: The use of testing techniques as allowed in this 49 CFR 192, Subpart O, to ascertain the condition of a covered pipeline segment.

ATMOSPHERIC CORROSION: As referred to in this policy, this refers to actual loss of metal on any above ground pipeline or facility by means of rusting or other oxidation. Such corrosion is normally evident in the form of actual pitting, flaking, or exfoliation of the metal. Exposure to certain reactive chemicals in the atmosphere may also result in deterioration of metal surfaces.

AUTHORITY HAVING JURISDICTION: The organization, office, or individual responsible for approving equipment, installation, or a procedure. The authority having jurisdiction may be the city, county, or other local building official, the supplying utility, or other deputized agency or person per statute.

AUTOMATIC IGNITION: An ignition system that requires no manual attention to ignite the main burner. Safety monitoring controls verify safe operating conditions at all times.

AUTOMATIC SHUT-OFF VALVE (ASV): An actuated valve that is shut automatically, either through physically sensing abnormal conditions (earthquake, pressure exceedance, etc.), or through electronic sensors and controls that send a signal to automatically shut a valve after detection of an abnormal event such as rupture.

BACKFILL: Earth or other material which is used to refill a ditch or trench. Also, the act of refilling a ditch or trench.

BACKFILL (CP): The material, which is placed around anodes to ensure uniform corrosion and, in certain instances, to extend the useful life of the anode. Coal coke or petroleum coke is used in conjunction with carbon or Duriron anodes; while a mixture of gypsum, bentonite, and salt is used with zinc, magnesium, and scrap iron anodes.

BAR HOLE: A hole in the ground made with a probe. Bar holes are normally made over buried gas pipelines to determine the presence of escaping natural gas.

BAR HOLE SURVEY: An area search for leaks, made by driving or boring bar holes at regular intervals along the route of an underground gas pipe and testing the air from the bar hole for their gas content.

BEDDING: See PADDING

BELL HOLE: An enlarged hole other than a continuous trench, dug over and along the side of buried pipelines or in a trench to allow room for persons to perform maintenance-related work on the pipeline (i.e., coating repairs, welding, connections, or pipe replacement). In the broad sense, any larger hole, other than a ditch, opened for pipeline work. Smaller holes may be called key holes or potholes.

BLIND FLANGE: A disk for closing the end of a pipe, having holes for bolting it to a flange. Such devices can be used to fulfill regulations concerning the inactivation of customer meters or facilities.

BLOCK VALVE: A valve in a main line that is designed to close in or shut down gas flow.

BLOWDOWN: The depressurizing of a natural gas pipeline to facilitate maintenance on the pipeline, accomplished by opening a valve and allowing the gas to escape to atmosphere, usually through a vertical pipe or "stack".

BOND: A connection, usually metallic, that provides electrical continuity between structures that can conduct electricity.

BTU: British Thermal Unit. One BTU is the amount of heat required to raise one pound of water one Fahrenheit degree.

BUILDING: A structure or dwelling designed for occupancy or storage with sides enclosed which could trap gas.

BUSINESS DISTRICT: An area where the public regularly congregates or where the majority of buildings on either side of the street are regularly utilized for financial, industrial, religious, educational, health, or recreational purposes. Mains in the right of way adjoining a business district must also be included in the leak survey.

BUTT FUSION: Joining process for two pieces of polyethylene pipe and/or fittings in which heat fusion is used and materials are joined by "butting" or pushing heated ends together.

BYPASS: A valve or assembly installed on a pipe, in a meter set or in a regulator station which allows the gas to flow in a path that is not part of the normal operating conditions, usually associated with a meter or regulator for maintenance purposes.

BYPASS CUSTOMER: A customer receiving gas directly from a transmission pipeline company or other gas company other than Avista. Pressure reducing regulators are normally found at such stations.

CALIBRATION: The act of formally determining the accuracy of an instrument or device and making required adjustments if it is found to be out of tolerance. Such action is normally carried out by a certified test facility but in some instances, may be performed by the Gas Meter Shop. (Also, refer to the definition of "verification" herein this glossary.)

CALL-OUT LIST: A list of qualified employees that are available on a round-the-clock basis to respond to emergency and service requests. This list is normally retained in the gas control room and is updated and reviewed by the Operations Manager.

CAN (BARREL): To encapsulate a portion of carrier facility (pipe, fitting, valve, etc.) for the purpose of repairing or rendering that portion of the facility leak-free. Cans must be rated to at least at the same MAOP as the encapsulated facility.

CAN'T-GAIN-ENTRY NOTICE: A Company approved form that advises the customer that an employee has visited the premises for a certain purpose, and that the order could not be completed as scheduled for one or more reasons.

CARBON MONOXIDE: A toxic and combustible gas produced during the incomplete combustion of hydrocarbons (such as natural gas). Carbon monoxide is colorless and odorless. Inhalation of carbon monoxide may cause sickness and death. The chemical formula is CO.

CARBON MONOXIDE (CO) DETECTOR: An alarm / device to detect carbon monoxide before most people experience symptoms.

CARRIER PIPE: The pipe or piping that goes through a casing.

CASING: A metallic pipe (normally steel) installed to contain a pipe or piping.

CASING INSULATOR: A dielectric device specifically designed to electrically isolate a carrier pipe from a casing and provide support for the carrier pipe.

CATHODE: The electrode of a corrosion cell where a net reduction reaction occurs. In corrosion processes the cathode is usually that area which does not corrode.

CATHODIC FIELD: The area in which the soil potential is lowered because of current flow to a ground electrode (pipeline). The extent of this influence is a function of soil resistivity and current density in the soil.

CATHODIC PROTECTION (CP): Reduction or prevention of corrosion of a metal surface by making it cathodic; for example, using sacrificial anodes or impressed current rectifier protection systems.

CHIMNEY EFFECT: The tendency of air or gas in a duct, vertical passage, or building to rise when heated because its density becomes less than the surrounding, colder air or gas.

CITY GATE: See Gate Station.

CLASS LOCATION: A geographic area representing population levels, as classified, and described in §192.5.

CLOCK TEST: Refer to "Meter Clock Test."

CLOSE INTERVAL SURVEY: A series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.

CLOCKING INPUT: The measurement of the volume of gas that an appliance consumes during a given period. The test dial on the gas meter is used to time how long it takes for one complete revolution. This time is then used in the clocking formula to determine gas consumption. The formula is: 3600/time in seconds x the dial size = the quantity of gas. The figure must then be converted into BTU per hour by multiplying by 1,000. (Note: an exact figure can be obtained by using the existing BTU value per cubic foot of gas as supplied.)

COATING: A liquid, liquefiable or mastic composition that, after application to a surface, is converted into a solid protective, decorative or functional adherent film.

COATING RESISTANCE: The electrical resistance of a coating to the flow of current. Unit of measurement is ohms per square foot. Values range from 1000 ohms to more than 1,000,000 ohms per square foot for conventional organic coatings.

CODE 5: Avista code word for a gas leak or gas odor.

CODE 9: Avista code word for a blowing gas situation.

COMBINATION CONTROL: An operating control that contains more than one switch to monitor different functions. A fan/limit control is an example of a combination control.

COMBINATION VALVE: A gas valve that contains a regulator, a main shut-off, and an operator all in one manufactured unit.

COMBUSTIBLE GAS INDICATOR (CGI): An instrument designed to obtain a sample of the air in a bar hole or in an atmosphere and indicate a percentage of gas in air or ppm reading. Combustible gas indicators are used to determine the presence or absence of natural gas, to center or pinpoint underground leakage, and to quantify the amount of gas detected.

COMBUSTION AIR: The air supply required for complete combustion of natural gas.

COMBUSTION PRODUCTS: By-products resulting from the combustion of a fuel with the oxygen of the air- but excluding excess air.

COMBUSTION TURBINE: An electric generator that uses a jet engine as the prime mover. Often fueled by natural gas or other petroleum products and typically used as a peaking plant.

COMMAND CENTER: A centralized location that exists for the purpose of coordinating the activities of emergency response personnel. This term may also apply to a temporary headquarters or communications center set up by the Company to coordinate activities of personnel during an emergency.

COMPLETE (RECORDS): Complete records are those in which the record is finalized, as evidenced by a signature or date.

COMPOSITE MATERIALS: Materials used to make pipe or components manufactured with a combination of either steel and/or plastic and with a reinforcing material to maintain its circumferential or longitudinal strength.

COMPRESSED NATURAL GAS (CNG): Natural gas stored inside containers at a pressure greater than atmospheric air pressure, typically up to 3600 psig. CNG is normally placed in pressure-containing vessels (bottles) where it can be used as a portable fuel source (i.e., in CNG vehicles and other applications not attached to a pipeline).

CONCENTRATION CELL: A corrosion cell due to the potential difference between the anode and cathode caused by differences in composition of electrolyte.

CONDUCTOR: A substance or body that allows an electric current to pass continuously along it.

CONDUIT: Plastic pipe installed to enable road construction, etc., prior to installation of plastic gas mains or services where the plastic line is inserted at a later date. Also used to describe steel services that have been inserted with a new gas service pipe.

CONFINED SPACE: Any space that is large enough for an employee to fully enter and perform assigned work, is not designated for continuous occupancy by an employee and has limited or restricted means of entry or exit. Confined spaces may include, but are not limited to, tanks, vessels, silos, storage bins, hoppers, vaults, pits, manholes, tunnels, equipment housings, bridge enclosures, etc. Refer to the Avista Incident Prevention Manual (Safety Handbook), Part 2, Section 15 – Confined/Enclosed Spaces, for additional guidance.

CONFIRMED DISCOVERY: When it can be reasonably determined, based on information available to Avista at the time that a reportable event has occurred, even if only based on a preliminary evaluation.

CONSTRUCTION OFFICE: As referred to in this policy, the main operating headquarters for a region, where the persons responsible for supervision of daily construction and service activities are located. This may also be referred to as "areas", "regions", “districts”, or other terms.

CONTROL: Any device, mechanical or electrical, which monitors or activates a piece of equipment.

CONTROL ROOM: An operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

CONTROLLER: A qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operations functions of the pipeline facility as applicable.

COPPER-COPPER SULFATE ELECTRODE: A standard or reference electrode used for determining potentials of metals in soils or other electrolytes.

CORRECTING DEVICE: An instrument installed on a meter to correct for varying pressures or temperatures of the gas stream. The corrector can be electronic or mechanical.

CORRECTION CODE: A billing code that identifies certain assumptions related to metering pressure and temperature.

CORROSION: The deterioration of a substance, usually a metal, resulting from a reaction with its environment.

CORROSION CELL: A term used to describe the environment in which an anode, cathode, electrolyte, and an electrical connection exist in which there is active current flow.

COUPLING: A sleeve-type fitting used to connect two pipes.

COVERED TASK: A covered task is an activity, identified by the operator, that (1) Is performed on a pipeline facility, (2) Is an operations or maintenance task *(state of Washington includes new construction)*; (3) Is performed as a requirement of Part 192; and (4) affects the operation or integrity of the pipeline. (Refer to Specification 4.31, Appendix A for the list of covered tasks.)

CROSS BORE: A utility cross bore is an intersection of an existing underground utility or underground structure by a second utility installed by trenchless technology that results in direct contact between the two and thereby compromises the integrity of either utility or underground structure.

CURB VALVE: A manually operated valve located near the service line that is safely accessible to Avista personnel or other personnel authorized by Avista to manually shut off gas flow to the service line, needed. (Definition taken from §192.385)

CURRENT: The movement of charged particles in a material. Measured in amps.

CURRENT DENSITY: As related to Cathodic Protection, the current per unit area of electrodes, usually expressed in terms of milliamperes per square foot.

CURTAILMENT: Reductions of deliveries of natural gas by interstate pipelines to distribution or end-use customers. This situation occurs when demand for natural gas exceeds supply, causing pipelines; or local distribution systems; to curtail their deliveries.

CUSTOMER: The person paying the gas bill or requesting gas service.

CUSTOMER PROJECT COORDINATOR (CPC): A person responsible for construction development, design, layout, pricing, scheduling, etc. This may also be referred to as "construction design rep (CDR)" or "marketing design technician (MDT)" or other titles.

CUSTOMER SERVICES DEPARTMENT: The department of the Company that is responsible for handling customer calls, answering, and resolving billing issues, originating orders for new and subsequent service, handling high bill complaints, answering emergency calls, etc. This may also be referred to as the "call center" or the "business office."

DAMAGE: The substantial weakening of structural or lateral support of an underground facility, penetration, impairment, or destruction of any underground protective coating, housing or other protective device, or the severance (partial or complete) of any underground facility to the extent that the project owner or the affected facility owner or facility operator determines that repairs are required.

DEFLECTION: The distance a pipe may be displaced under load.

DEGREE DAY (HEATING DEGREE DAY – HDD): A measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below a reference temperature, usually 65 degrees F.

DEKATHERM: Unit of measurement for natural gas; a dekatherm is equal to approximately one thousand cubic feet (volume) or 1,000,000 BTUs (energy).

DELAYED IGNITION: The improper lighting of a main burner causing an explosion during ignition. The sound of delayed ignition can range from a mild rumble to a thunderous bang depending on the severity of the problem. The customer's concerns and perceptions should be used in determining the existence of a delayed ignition condition.

DELIVERY PRESSURE: The pressure delivered to the customer piping. Also, it is referred to as the "service pressure" or the "utilization pressure."

DESIGN FACTOR: The percentage of SMYS to which operating stress must be limited as described in §192.111.

DESIGN PRESSURE: The minimum pressure that new facilities within a system should be designed. This pressure determines the minimum required test pressure to establish MAOP as well as the required component characteristics for design.

DIELECTRIC: A fitting or component that is partially made of a non-conducting material such as plastic. These fittings are designed to prevent electrolysis from damaging metal surfaces and to interrupt CP current.

DIRECT AND OBSERVE: The process by which a qualified individual oversees the work activities of a nonqualified individual(s) and is able to take immediate corrective action when necessary.

DISTRIBUTION: A pipeline system within which hoop stress within pipe is less than 20 percent of specified minimum yield strength (SMYS).

DISTRIBUTION CENTER: The initial point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale, for example:

1) At a metering location;
2) A pressure reduction location; or
3) Where there is a reduction in the volume of gas, such as a lateral off a transmission line.

DISTRIBUTION SYSTEM: A pipeline system with a MAOP at less than 20 percent of specified minimum yield strength.

DISTRICT REGULATOR STATION: A pressure regulating station that controls pressure to high- or low-pressure distribution main. It does not include pressure regulation whose sole function is to control pressure to a manifold serving multiple customers. Assembly utilizes either a regulator and relief or regulator and monitor to reduce pressure. Master meter stations and bypass customer stations are treated like district regulator stations and are maintained accordingly.

DOUBLE SUBMERGED-ARC-WELDED PIPE (DSAW): Steel pipe which has a longitudinal butt joint wherein coalescence is produced by at least two passes including at least one inside and one outside the pipe with an electric arc.

DOWNSTREAM PIPING: The customer owned piping which typically begins at the outlet of the meter or the regulator, whichever is furthest downstream. Also, it is referred to as “house line” or “house piping.”

DRY GAS: Gas above its dew point and without condensed liquids. For most operator established tariff purposes, any gas containing water vapor less than 7 pounds per million cubic feet (mmcf) is considered dry gas.

DUNNAGE: Wood material, usually 2x4's or 4x4's, placed between lifts of pipe to keep pipe from being damaged. Dunnage can also be used to help support pipe during pipe end alignment. May also be called cribbing or skids.

ELECTRIC RESISTANCE WELDED PIPE (ERW): Pipe which has a longitudinal butt joint wherein coalescence is produced by the application of pressure and by heat obtained from the resistance at the weld to electric current.

ELECTRODE: Either the corroding or non-corroding portion of a corrosion cell; Refer to anode or cathode, whichever is appropriate. Also, it is used loosely to describe half-cells such as the copper-copper sulfate reference electrode.

ELECTROLYSIS: The production of a chemical change in an electrolyte resulting from the passage of electricity and often traditionally used to describe any and all forms of corrosion.

ELECTROLYTE: An ionized chemical substance or mixture that will conduct electric current, such as water, soil, or many chemical solutions.

ELECTRO-NEGATIVE: A term used to designate the metal most likely to corrode in a bimetallic corrosion cell. Magnesium and zinc, for instance, are electro-negative with respect to copper or steel. In the same relationship, copper and steel are electro-positive.

ELECTRONIC IGNITION: An ignition system which uses a high open-ended voltage to produce a high temperature spark to ignite the pilot or main burner.

ELEVATED DELIVERY PRESSURE: Any delivery pressure in excess of 7-inches WC (water column) or 1/4 psig.

EMERGENCY: For the purposes of this handbook, any situation, occurrence, or incident that requires immediate action to protect life and / or property.

EMERGENCY OPERATING PLAN (EOP): A plan required by Federal regulations that details procedures to be followed to ensure the safety of the public and/or employees in the event of a natural gas related emergency.

EMERGENCY SERVICES: Any public or private agency which has the primary responsibility to respond to emergencies. This includes police departments, state patrols, fire departments, hazmat teams, ambulance services, paramedics, etc. These agencies are normally accessed by dialing “911”.

EMERGENCY SHUTDOWN: Taking actions that are designed to shut down a station, facility, or system or to change to a reduced operational state in the event of a failure or hazardous situation.

EMERGENCY VALVE: A valve that may be necessary for the safe operation of a transmission or distribution system. Such valves must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year. (Note: An EOP valve is a type of emergency valve, but the names are not synonymous. See “EOP Valve” definition for further information.

EMPLOYEE: Also referred to in this policy as "gas employee", "service person", and other titles. Denotes any person in the employ of Avista Utilities who may be responsible for carrying out the duties as described in this handbook, or as detailed in the O & M plan. May also refer to contract employees depending on the context of the policy and current Union/Company agreements.

ENCODER, RECEIVER, TRANSMITTER (ERT): An auxiliary device installed on meters to allow for remote reading.

ENTIRELY REPLACED ONSHORE TRANSMISSION PIPELINE SEGMENT: A segment of transmission pipeline that has 2 or more miles, in the aggregate, of pipeline replaced within any 5 contiguous miles of pipeline within any 24-month period.

EOP VALVE: Distribution or transmission valves that are located in key positions to enable quick isolation and shut-down of a pipeline during an emergency. An EOP valve is a type of Emergency Valve.

EROSION: Deterioration by the abrasive action of fluids, usually accelerated by the presence of solid particles of matter in suspension. When deterioration is further increased by corrosion, the term erosion-corrosion is often used.

EVACUATION: The process of removing or assisting in the removal of persons from an area or structure in order to avoid danger.

EVALUATION: A process established and documented to determine an individual's ability to perform a covered task by various methods.

EVALUATOR: An individual selected or credentialed to conduct performance or oral interview evaluations to determine if an individual is qualified.

EXCESS FLOW VALVE (EFV): A device that is designed to automatically shut off the flow of gas should the service line be severed.

EXPLOSIVE LIMITS: Lower and upper percentages expressing a range of fuel-to-air mixtures that will burn when exposed to a high enough temperature to cause ignition. The explosive limits of natural gas are approximately 5 percent to 15 percent gas in air but may range slightly lower or higher depending on the methane content of the gas. Ratios outside these should not combust or explode. The explosive limits for propane are approximately 2 percent to 10 percent.

FABRICATED UNIT: An assembly of two or more fittings and/or pieces of pipe joined together.

FACILITY, GAS: A Company gas pipeline, meter set, fitting, station, or other related appurtenance used in the distribution of natural gas to Avista's customers.

FARM TAP (SINGLE SERVICE FARM TAP-SSFT): A pressure regulating station that controls pressure to a service line. Assembly usually utilizes a regulator and relief to reduce transmission or distribution pressure to 60 psig or less.

FIELD INVESTIGATION: Avista's procedures for responding to gas related incidents, accidents, failures, or fires (Gas Field Incident Investigation, GESH Section 17 and/or Leak and Odor Investigation GESH Section 2). After investigating to resolve the emergency, personnel will collect data to document or record the scene of the incident site (ref: GESH Section 17 sheet 3 of 8 "Recording the Scene")

FIRM CUSTOMERS: Natural gas customer for whom contract demand (supply or capacity) is reserved and to whom the seller (pipeline or producer) is obligated to furnish service at all times, except in cases of force majeure.

FITTING: A component used in a gas facility for changing direction, branching or for change of pipe diameter.

FITTING, PIPE (NON-RATED): A fitting that has physical characteristics (diameter, wall thickness, grade, etc.) similar to gas pipe and whose MAOP is determined based on those characteristics. These fittings require a pressure test to establish MAOP.

FITTING, RATED: A fitting that is designed to a specific standard (ANSI, ASTM, etc.) and has a designated pressure rating from the manufacturer.

FLAME IONIZATION UNIT: Also referred to as an "F.I. Unit" and "Flame Pak". An extremely sensitive gas leak detection instrument that senses the presence of methane gas by measuring the ions produced in a hydrogen flame when gas is burned. F.I. Units can normally detect methane down to 1 ppm.

FLOW PRESSURE: The pressure within a piping system that exists when there is a certain amount of flow through a meter set that is representative of a "normal" load.

FLOW RATE: A volume of gas measured over a given time. The flow rate is generally measured in cubic feet per hour (CFH) and is sometimes used synonymously with "load" although technically these are not the same.

FLUE GASES: Normal products of combustion: carbon dioxide and water vapor, which are vented into the outdoor atmosphere through a flue pipe.

FORCE MAJEURE: A superior obligation, "act of god," or any other unexpected and disruptive event, which may serve to relieve a party from a contract or obligation.

FORCED AIR: An air delivery system that moves heated air mechanically with fans and blowers through ductwork.

FURNACE: A self-contained appliance, used in central heating systems, for heating air by transfer of heat of combustion through metal to the air.

GALVANIC SERIES: A list of metals and alloys arranged according to their relative electrolytic potentials to one another in a given environment. The metals or alloys higher on the list (more negative) are anodic to those lower on the list and the metals or alloys lower on the list (more positive) are cathodic to those higher on the list.

GAS OPERATING ORDER: A Company approved form or electronic process that serves as documentation of work performed in relation to installation of facilities, of work on customer premises, of meter changes or repairs, of response to leak and odor requests, etc. This form may take on different formats to accommodate the particular type of order being worked, or to fit the particular system being used to generate the order.

GAS SERVICE PERSON: A Company employee who has completed a minimum 2-year apprenticeship (or the equivalent) for the position of Gas Serviceman, and who has achieved "Journeyman" status through evidence of completion of all required or statutory courses and licensing.

GAS SHUT-OFF NOTICE: A Company approved form or electronic process that advises a customer that the gas service has been closed to facilitate repairs or due to other conditions.

GATE STATION: The point at which the distribution company (Avista) taps off a pipeline company (i.e., NWP or GTN). Custody transfer of gas occurs at this point. Even if only one customer is downstream of this station, it is still considered a Gate Station. Generally, regulating, odorizing, and metering equipment are found in a gate station. Other possible names for a gate station include meter station, town border station, and odorizer station. (If gas is not metered at the site, then the station is not considered a Gate Station, such as the regulator stations off the Williams NW 6-inch pipeline that runs between Mead and Starr Road Gate Stations.)

GATHERING LINE: A pipeline that transports gas from a current production facility to a transmission line or main.

GROUND BED: Refer to anode (cathodic protection).

HAZARDOUS CONDITION: Any condition that is causing or that may cause a hazard to persons or property. Such conditions require notification of the customer and issuance of the appropriate hazard notice.

HEAT EXCHANGER: A device used for transferring heat from one fluid to another without allowing them to mix, typically found in a forced air furnace.

HEAT FUSION JOINT: A joint made in thermoplastic piping (polyethylene piping) by heating the parts sufficiently to permit fusion of the materials when the materials are pressed together.

HIGH OCCUPANCY STRUCTURE OR AREA: A structure or area that is normally occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.) Structures and areas include churches, hospitals, schools, and may include assembly buildings, outdoor theaters, outdoor recreation areas, etc.

HIGH PRESSURE: Pressure that is greater than 60 PSIG.

HOLIDAY: A break or imperfection in a pipe coating.

HOLIDAY DETECTOR (JEEPING MACHINE): An electronic device for locating discontinuities or breaks in the protective coating on a pipe, tubing, or fitting.

HOOP STRESS: The stress in a pipe wall that acts circumferentially in a plane perpendicular to the longitudinal axis of the pipe and is produced by the pressure in the pipe.

IDLE METER: A meter installed on a service and the account is closed.

IGNITION TEMPERATURE: The temperature at which a substance, such as natural gas, will ignite and continue burning with adequate air supply.

IMMEDIATE RESPONSE: Any form of prompt action taken to save lives, prevent injury, or mitigate property damage under imminently serious conditions when time does not permit approval from a higher authority.

IMPRESSED CURRENT: Cathodic protection current provided by rectifier type protective systems.

INCHES OF WATER COLUMN: A standard unit of measurement typically used to describe the amount of gas pressure in units of less than 1 PSIG. The conversion for inches of water column is: 27.7" = 1 PSIG.

INCIDENT: An occurrence or event that happens in relation to Company gas facilities that warrants immediate or quick action, and that may require appropriate notifications of certain Company supervisory, or state or federal officials. Incidents may also be related to an emergency situation.

INCIDENT ASSESSMENT: Avista's formal program and processes for identifying improvement opportunities (organizational and individual) by assessing the practices, standards, and procedures, among other things that resulted in the incident or near miss. The goal is to identify corrective actions to prevent or at least reduce the consequences of a similar future incident or near miss.

INCONCLUSIVE: Not having a final conclusion. As applied to leak and odor investigations, any situation involving response to a leak or odor in which the cause or reason for the leak or odor is not evident at the conclusion of the investigation. An inconclusive leak or odor request requires additional action.

INDUSTRIAL METER SET: A meter set that meets any of the following criteria: It meters at a pressure greater than 5 PSIG; is a rotary meter size 16M or larger regardless of metering pressure; is a turbine meter; has a design hourly load equal to or greater than 14,600,000 BTU/Hr; or has a Meter Correction Code of 3 or P.

INERT GAS: A gas that is non-explosive and non-flammable. Operators use inert gases for testing and purging pipelines. The most common inert gas is nitrogen. High concentrations of inert gases may cause asphyxiation.

INFLECTION: A change in course or direction of a pipeline typically made by a bend or fitting.

INHIBITOR: A substance which retards corrosion when added to an environment in small concentrations.

INPUT RATING: The fuel burning capacity of the appliance in BTU/hr as specified by the manufacturer. Also referred to as “input” or “BTU input”.
INSULATOR: Pipe fittings such as unions, couplings, and flanges which permit electrical separation of one section of pipe from another. Refer to “Dielectric”.

INTERMEDIATE PRESSURE: Pressure that is 1 PSIG up to and including 60 PSIG.

INTERMITTENT IGNITION (IID): An ignition system that is activated only on a call for heat to reduce standby losses. The pilot burner is ignited by either an electric spark or a hot surface igniter. There may also be direct ignition of the burner from the ignition devices.

INTERNAL RELIEF VALVE (IRV): A relief valve that is built into many service regulators to relieve excess gas pressure above a certain set point. The internal relief valve will open and allow gas to escape to the atmosphere in cases where the set point is exceeded due to an operational malfunction.

INTERRUPTIBLE GAS: Service to a customer which under contract may be interrupted during periods of peak demand to the total system.

JEEP: An instrument used to detect imperfections (holidays) or damage to protective coating on steel pipe. It is also known as a holiday detector.

JOULE-THOMSON EFFECT: The cooling which occurs when a compressed gas is allowed to expand in such a way that no external work is done. The effect is approximately 7º F per 100 psi for natural gas.

LADDER POLICY: A company policy determining the circumstances in which a ladder may be used by company and contract personnel.

LANDFILL GAS: Gas which is composed of methane and carbon dioxide and produced by aerobic and anaerobic decomposition of organic solid waste in a landfill.

LATERAL: A pipe in a gas distribution or transmission system which branches away from the main trunk line.

LEAK: An uncontrolled or unauthorized discharge or escape of natural gas from the system.

LEAK CENTERING OR PINPOINTING: The procedure used to determine (normally within a radius of several feet) from where an underground leak is originating. The procedure involves making a series of bar holes in an area where gas may be migrating, measuring the gas-in-air mixture at each hole, and then determining the general location of the leak by analyzing the readings.

LEAK DETECTOR: A device for determining the concentration of gas in air.

LEAK TEST: A pressure test to determine the tightness of the system.

LIFT OF PIPE: One level stack of pipe.

LIMIT DEVICE: A temperature activated control designed to shut off the supply of gas in the event of an over temperature situation.

LIQUEIFIED NATURAL GAS: Natural gas or synthetic gas having methane (CH_4) as its major constituent which has been changed to a liquid by lowering the temperature.

LOAD: A means of expressing the quantity of gas require to service all appliances on a piping system over a period of one hour, as expressed in BTU/hour or in therms.

LOCAL DISTRIBUTION COMPANY (LDC): A local gas company responsible for distributing gas to its customers. An LDC purchases gas from transmission companies for resale to the consumer. LDC's operate and maintain the underground piping, regulators, and meters that connect to each residential and commercial customer.

LOCKUP PRESSURE: The gas pressure contained within a piping system when there is no consumption.

LOW PRESSURE: Operating at less than 1 psig. It is usually measured in inches of water column.

LOWER EXPLOSIVE LIMIT (LEL): The lower explosive limit of natural gas which varies slightly depending on the amount of methane present. For Avista, the LEL of natural gas is generally defined as 5 percent gas in air. Refer to “Explosive Limits” for more information.

MAIN: A pipeline serving as a common source of supply for more than one service line.

MANHOLE: Any inspection or access port for the maintenance or operation of equipment or components.

MANIFOLD: A common piping system used as an intersection for distribution of gas to more than one customer. A single service line and regulator typically feeds the inlet of the manifold. Several outlet, valves, and meters are installed on the manifold to serve individual customers.

MANOMETER (U-GAUGE): A "U" shaped tube, filled with water or another liquid with a specific gravity equal to water. It is used to measure pressure in units of inches of water column.

MANUAL SERVICE LINE SHUT-OFF VALVE – See Curb Valve.

MASTER METER STATION: A meter set serving a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source (Avista) for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents. Master meter stations are considered district regulator stations and are maintained accordingly.

MAXIMO: The IBM asset management system that tracks procurement, inventory, location, and work management for planned and unplanned work activities related to assets (including meters). In Gas Compliance, it is the system of record for scheduling, tracking and documenting gas maintenance activity.

MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP): The maximum pressure at which a gas pipeline or pipeline segment may be operated in accordance with the applicable regulatory codes. The MAOP of such a gas facility is determined by the "weakest link" within that facility and is the upper Safe Operating Limit. (See the definition of Safe Operating Limit below.)

MECHANICAL FITTING: Fittings that connect steel or PE components in a manner other than heat fusion or welding.

METER CLOCK TEST: Procedure where a test dial on a gas meter is observed for movement over time. The procedure is used to identify volume of flow through the meter.

METER DATA MANAGEMENT: The system that ensures the reliability and optimized use of available data from a smart meter system (AMI). MDM loads, validates, stores, and formats meter/usage data from smart meter sources and enables interface to other utility systems such as customer information, outage management, work force management, and geographical information.

METER ROOM: A room designed to house natural gas meter(s) that is within the confines of the building to be served.

METER SET ASSEMBLY (MSA): The equipment including meters, regulators, relief valves, etc. required to measure and deliver gas to a customer.

METER SPOT CHECK**:** A procedure where the test hand on a gas meter is observed for no movement.

METER SWIVEL: The fitting that connects to the inlet and the outlet of a small gas meter.

METER, GAS: An instrument for measuring, indicating, or recording the volume, mass, or energy of natural gas at its pressure and temperature at the time of measurement.

METERING PRESSURE: The pressure at which the meter is measuring gas.

MIL: A unit of length equal to 1/1000 inch used especially in measuring thickness (as in plastic films).

MINIMUM SAFE UTILIZATION PRESSURE: Enough pressure differential to maintain customers without pilot outage. This will typically be the Lower Safe Operating Limit. (See "Pressure Drops" in GESH Section 5, Page 3.)

MITER JOINT: Used instead of an elbow to change direction of pipe. A miter is made by cutting ends of pipes to be joined at angles.

MONITOR: Second regulator used in series configuration with the working regulator to maintain downstream pressure within the necessary limits of accuracy should the controlling regulator fail. Monitor acts as secondary backup regulator and does not release gas to atmosphere. The monitor may be located upstream or downstream of the working regulator.

NATIONAL TRANSPORTATION SAFETY BOARD (NTSB): An independent agency reporting administratively to the Secretary of the Department of Transportation, charged with the investigation of all safety-related incidents involving transportation. These include air, rail, highway, and certain liquid and gas pipeline transportation. The NTSB has no power to issue regulations; however, it issues reports and recommendations.

NATURAL GAS: A naturally occurring mixture of hydrocarbon and non-hydrocarbon gasses found in porous geologic formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

NEGATIVE PRESSURE: A condition that is created when more air is exhausted out of a building than is being replaced. This creates a partial vacuum in the building, so that air is forced down chimneys or vents causing the products of combustion to spill into the living space.

NEUTRAL PRESSURE POINT: The location in a converted appliance's combustion chamber between the positive pressure zone above the flame and the negative pressure zone below the flame. This point is usually set at about the firing door latch; however, the point may vary with heat exchanger design.

NEW CONSTRUCTION RISER: An anodeless riser that is field fabricated and comprised of a galvanized steel sleeve, PE pipe, and service head adapter. A new construction riser can be built in custom lengths to accommodate instances where the standard manufactured anodeless riser is insufficient.

NON-OBSERVABLE TASK: A task that can only be performed by a qualified individual.

NON-QUALIFIED: An individual not qualified to perform a covered task.

NOTIFICATION OF POTENTIAL RUPTURE: Means the notification to, or observation by, an operator of conditions indicative of a potential unintentional or uncontrolled release of a large volume of gas from a pipeline. In the case of Avista, a "large volume of gas" is interpreted to be 3 million cubic feet (3 MMCF).

ODORANT: A substance giving a readily distinctive perceptible odor at low concentrations in natural gas. It is used as a method of detection of the presence of natural gas, as natural gas itself has no odor.

ODORIZATION: The process of adding an odor to natural gas. Since natural gas is odorless, odorant is added to the gas so that people can smell escaping or leaking gas and report the situation to a gas company for further investigation.

ODORIZER: A piece of equipment that adds chemical odorant to flowing natural gas pipelines.

ODOROMETER: A device used to detect the amount of natural gas as a percentage of gas in air at the point the odorized gas can be detected by a person with a normal sense of smell.

OHM: The unit of measurement of electrical resistance.

ONE-CALL SYSTEM: A utility coordinating and notification system that allows for requests for locations of underground facilities to be forwarded in a timely manner to the appropriate utility for field locating and marking.

OPERATING STRESS: The stress in a pipe or structural member under normal operating conditions.

OPERATION OF A PIPELINE: The starting, stopping, changing, or monitoring of pressure, flow, and temperature of product through a pipeline.

OPERATIONS MANAGER: Supervisory person in charge of a particular operating area. The operations manager may also be referred to as a "regional manager", “district manager”, “construction manager”, “supervisor", or "area coordinator".

ORIFICE: The opening in an orifice cap, orifice spud, whereby the flow of gas is limited and through which the gas is discharged.

OVERPRESSURE PROTECTION (OPP): Any device that ensures that the maximum allowable operating pressure of a piping system is not exceeded. These devices may include, but are not limited to relief valves, safety shutoff valves, and monitor regulators.

OXIDATION: The loss of electrons by a constituent of a chemical reaction occurs at anode.

P/S (PIPE TO SOIL): A measurement of the difference in potential between a pipeline and a copper-copper sulfate half-cell electrode in contact with an electrolyte.

PADDING: The placing of material free of any hard objects (rocks, etc.) below, around and above the pipe during backfill in order to protect the pipe surface from puncture or excessive abrasion. (Sometimes referred to as “bedding”.)

PATCHING: Method of repairing damaged pipe where piece of metal usually less than 1/2 the circumference of the damaged pipe is welded over the damaged section of pipe.

PERIMETER: When conducting a leak investigation, an area that reasonably surrounds the initial underground leak location.

PERSONAL PROTECTIVE EQUIPMENT (PPE): Personal equipment that protects the individual who wears it by placing a barrier between that individual and a potential or known hazard. Examples of PPE include protective eyewear, face shields, masks, gloves, boots, hats, clothing, and respirators.

PIG: A device used to clean debris or scale from internal pipe walls and to purge water from pipe after hydro testing. Pigs are usually forced through pipe by air compressors, but sometimes are pulled with cables. The word is also used to refer to a sophisticated internal inspection device (smart pig) used to assess the integrity of pipelines. See Smart Pig.

PILOT: A small flame which is utilized to ignite gas at a main burner.

PINPOINTING: The process of locating the exact source of a gas leak along a pipeline route with a minimum of excavation. This is accomplished using a gas measuring analyzer and a non-sparking metal plunger bar to punch holes in the ground along the pipeline's right-of-way (see "centering").

PIPELINE: All parts of those physical facilities through which gas moves. This includes but is not limited to pipe, valves, and other appurtenances.

PIPELINE COMPANIES: Companies that deliver gas to Avista gate stations.

PIPELINE SAFETY: Protection of the public, employees, and pipeline against the consequences of physical failure, human error, organizational failure, damage, or other undesirable events.

PITTING: Localized corrosion of a metal surface that is confined to a small area and takes the form of cavities called pits.

PLUG: An external thread pipe fitting that is inserted into the open end of an internal thread pipe fitting to seal the end of the pipe. Also, the act of sealing a hole in a vessel, such as a pipe or tank, by inserting material in the hole and then securing it, and the material used to seal the hole.

POLARIZATION: The change of electrode potential resulting from the effects of current flow, measured with respect to steady state potentials.

POLYETHYLENE: The material used to manufacture plastic pipe and some plastic fittings. When the term “plastic” is used, it is typically synonymous with “polyethylene” or “PE”.

PREFABRICATED UNIT (PRESSURE VESSEL): A fabrication that uses plate and longitudinal seams, or an assembly utilizing components that do not have a readily available design pressure.

PREFABRICATED WELDED ASSEMBLIES: An assembly consisting of regularly manufactured butt-welding fittings, ASTM A-53, A-105 or API 5L pipe, and standard valves. All components shall be connected by circumferential welds. These are exempt from the “Prefabricated Unit and Pressure Vessel” requirements in Spec 2.12 and §192.153.

PRESSURE DROP: Refer to “Allowable Pressure Drop.”

PRESSURE TEST: A test performed by pressurizing a gas line for a predetermined length of time. A successful pressure test will show no unaccounted-for loss in pressure as indicated on a recording chart, pressure gauge, or water manometer, thus indicating that the system is gas tight. Also referred to as an “air pressure test.”

PRESSURE VESSEL: Refer to “Prefabricated Unit.”

PROPANE: A gaseous member of the paraffin series of hydrocarbons, that, when liquefied under pressure, is one of the components of liquefied petroleum gas (LPG). Propane contains approximately 2,500 British thermal units (Btu) per Cubic foot. Although it is gaseous at ordinary atmospheric conditions, it is readily compressed into a liquid. It is highly volatile, odorless, and colorless.

PSI (pounds per square inch): The unit of pressure or measure of force on a given area. Within the oil and gas industry, psi normally refers to the pressure of the gas or product contained within the pipeline or pressure vessel. (Typically shown in lower case letters.)

PSIA (pounds per square inch, absolute): The pressure expressed in pounds exerted on one square inch of surface area. The absolute refers to the total pressure sensed including the surrounding atmospheric pressure. (Typically shown in lower case letters.)

PSIG (pounds per square inch, gauge): The pressure expressed in pounds exerted on one square inch of surface area. The designation "gauge" indicates the readings are already adjusted or biased to ignore the surrounding atmospheric pressure which is 14.7 psi at sea level. If a PSIG type of gauge were not connected to any pressure source, it would read zero even though it is actually sensing 14.7 psi at sea level. (Typically shown in lower case letters.)

PUBLIC UTILITY COMMISSION: State agencies that inspect pipeline safety and regulate the tariffs (pricing) of investor-owned utility companies.

PUMPKIN: A reinforcing sleeve welded over a coupling or other fitting.

PURGE: To free a gas facility of air or gas, or of a mixture of gas and air. Purging is required when bringing new or existing facilities into service from a depressurized state or after a facility has been blown down/depressurized to perform work on or abandon an existing facility.

QUALIFIED: An individual that has been evaluated and can perform assigned covered tasks and is able to recognize and react to abnormal operating conditions.

RADIANT HEAT: Heat energy that is emitted from an object to the surrounding atmosphere.

RADIOGRAPHIC INSPECTION: Method used to determine flaws in pipe or other metals by use of a machine that emits x-rays or gamma rays which penetrate the metal and are transcribed onto film.

RANGE: A cooking appliance which usually includes several top burners above, and an oven and broiler below. Also referred to as a “stove” or “cook stove”.

READ: The volume of gas measured in cubic feet (CF) by the gas meter. A cubic foot of gas measured at standard pressure and temperature contains approximately 1000 BTUs of energy.

READING: A repeatable (sustained) representation on a device such as a combustible gas indicator, a pressure gauge, etc.

RECTIFIER: A device used to convert alternating current (AC) to direct current (DC) and used in the gas industry for external corrosion control of pipe and other metals.

REDUCTION: Gain of electrons by a constituent of a chemical reaction, occurs at cathode.

REFERENCE ELECTRODE: An electrode whose open-circuit potential is constant under similar conditions of measurement, which is used for measuring the relative potentials of other electrodes. (Often referred to as a "half-cell".)

REGULATION: The process of reducing and controlling pressure.

REGULATOR: Device used to maintain a constant downstream pressure. Also known as a Pressure Regulator.

REGULATOR VENT: The opening in the atmospheric side of the regulator housing permitting the free movement of the regulator diaphragm.

REGULATOR, SERVICE: A device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

RELIEF: Device used to maintain downstream pressure within necessary limits by relieving gas to atmosphere should the working regulator fail.

REMOTE CONTROL VALVE (RCV): A valve that is operated from a location remote from where the valve is installed. The RCV is usually operated by a controller via the SCADA system. The linkage between the pipeline control center and the RCV may be by fiber optics, microwave, telephone lines, or satellite.

REMOTE METER: A meter that is installed more than three feet from a building or foundation wall.

RENEWABLE NATURAL GAS: Pipeline-quality biomethane produced from biomass. It is interchangeable with natural gas. It is carbon neutral, extremely versatile and fully compatible with the U.S. pipeline infrastructure.

REPLACED SERVICE LINE: A gas service line where the fitting that connects the service line to the main is replaced or the piping connected to this fitting is replaced.

RESISTIVITY: The relative degree to which soil or water resists the flow of electric current. The most common terms in use are the ohmmeter and the ohm-centimeter.

REVERSE CURRENT SWITCH: A bond designed and constructed such that CP current can pass in only one direction.

RISER: A general term for vertical runs of piping regardless of the size or application. (The most common reference at Avista would be a "meter riser" which is the piping that connects underground service piping to the gas meter.)

RUPTURE-MITIGATION VALVE (RMV): An automatic shut-off valve (ASV) or remote-control valve (RCV) that is used to minimize the volume of gas released from the pipeline and to mitigate the consequences of a rupture.

RUST: Corrosion product consisting primarily of iron oxide. A term properly applied only to iron and other ferrous metals.

SACRIFICIAL PROTECTION: Reduction or prevention of corrosion of a metal in an environment by coupling it to another metal which is electrochemically more active in that environment.

SAFE OPERATING LIMIT: A limit established for a critical process parameter such as temperature, pressure, or flow, and based on equipment design limits and the dynamics of the process.

SAFETY DATA SHEET: Document that contains information on the potential health effects of exposure to chemicals, or other potentially dangerous substances, and on safe working procedures when handling chemical products.

SAFETY DEVICES: Devices designed to forestall the development of a hazardous or undesirable condition in the piping system, in the equipment, in the medium being treated, or in the combustion products.

SEAMLESS PIPE: Steel pipe which has no longitudinal butt joint. It is manufactured by hot working the tubular product (usually over a mandrel) into the desired shape.

SEGMENT (PIPELINE SEGMENT): A section or length of gas facility that typically has the same physical pipe characteristics (diameter, grade, wall thickness, etc.) and which the MAOP was established under the same pressure test. A segment may include valves and fittings that have different characteristics from the connected line pipe.

SELF TAPPING TEE: A service tee with a self-contained cutter which is installed on in-service pipe for drilling a hole in the pipe.

SERVICE (SERVICE LINE): A distribution line that transports gas from a common source of supply to an individual customer to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the meter or at the connection to a customer's piping if there is no meter.

SERVICE HEAD ADAPTER: A PE to steel transition fitting most commonly used on a new construction riser or a steel service that is inserted with PE pipe. The fitting is threaded onto the outlet of the steel riser and allows for the attachment of the meter valve.

SERVICE REGULATOR: See Regulator, Service.

SERVICE VALVE or SERVICE-LINE VALVE: A valve located in a service line and located upstream of the service regulator, meter, any meter bypass where there is no service regulator, or connection to customer piping if there is no meter.

SHALL: Indicates that a provision is MANDATORY for completion. The word "must" is a synonym and requires similar treatment in these standards.

SHIELDING: High resistance or non-conducting material preventing CP current from reaching the structure, or low resistance material diverting the current away from the structure to be protected.

SHORT: An inadvertent, undesirable contact between two buried metals, or the electrical failure of installed insulation which destroys the desired metallic isolation of a piping system.

SHORT SECTION OF PIPE: A single piece of pipe containing no girth welds (steel) or fusion joints (PE).

SHORTED PIPELINE CASING: A casing that is not electrically isolated from the carrier pipe. Generally, this term is used for casings that are in direct metallic contact with the carrier pipe.

SHOULD: Indicates a provision that although not mandatory, is the preferred method and strongly recommended as a best practice. There must be a substantial reason for not completing such provisions within Avista's Gas Standards and oftentimes non completion of these provisions must be documented with a reason.

SHUT-OFF VALVE (Pertaining to overpressure protection): Device used in series configurations with regulator to maintain downstream pressure within necessary limits by shutting off gas supply should the regulator fail.
SINGLE SERVICE FARM TAP (SSFT) – See Farm Tap Regulator

SLEEVING: Method of repairing damaged pipe where metal is welded around the full circumference of the pipe over the damaged section. Sleeves usually come in two halves.

SMART PIG: Any of a variety of internal pipe inspection devices. These devices, or "pigs", measure and record the internal geometry, external or internal corrosion as well as provide information about pipe characteristics such as wall thickness and other pipe defects. Magnetic flux leakage, ultrasonic, calipers, and geometry are examples of smart tools; also referred to as ILI tools.

SOAP TEST: A test for gas leaks, which involves wiping or brushing the joints to be tested with a soap and water solution, typically performed at no less than the operating pressure of the facility. Any leaks on the piping will be identified by the formation of bubbles.

SOIL POTENTIAL GRADIENT: The voltage drop in the soil caused by direct current flowing away from or to a ground electrode, anode, or cathode. The voltage gradient is measured between two copper-copper sulfate half-cell electrodes a set distance apart on a radius line from the ground electrode.

SOUR GAS: Natural gas contaminated with chemical impurities, notably hydrogen sulfide or other sulfur compounds, that impart a foul odor to the gas. Such impurities must be removed before the gas can be used for commercial and domestic purposes.

SOURCE OF IGNITION: Any device or object that is capable of producing a source of heat of sufficient temperature to ignite natural gas. Examples of such devices or objects are radios, matches, heating equipment, motors, static electricity, light switches, etc.

SPAN OF CONTROL: The maximum number of non-qualified individuals that a qualified individual can direct and observe under Operator Qualification rules.

SPECIFIED MINIMUM YIELD STRENGTH (SMYS): The minimum yield strength prescribed by the specifications under which pipe or non-rated pipe fittings are manufactured and sold.

SPOT CHECK: Refer to “Meter Spot Check”

STANDARD CONFIGURATION: As specified by drawings in the Gas Standards Manual.

STANDARD METERING PRESSURE: The pressure at which most residential meters measure gas. Usually 7-inches WC (water column) or 1/4 psig. In some areas, it is 8-inches WC.

STATIC ELECTRICITY: An electric charge, which builds up on an insulated object usually as a result of friction. Static electricity will discharge as soon as it come close to a metallic object or other conductor and will create a bluish spark and snapping sound. In gas leak situations, the spark from static electricity is hot enough to cause ignition of flammable gas-in-air mixtures.

STRAY CURRENT: Electrical current (normally direct current, DC), from either a natural or man-made source, that could result in pipe corrosion if not properly drained or compensated for by other means.

STRENGTH TEST: A quality control check of the structural integrity of a pipeline performed by filling the line with a liquid or gas and applying a specified pressure for a prescribed period of time. May be called a pressure test. If water is used as the testing medium, it may be called a hydrotest.

STRESS: The magnitude of the internal and/or external forces that act on a structure.

STRESS CORROSION CRACKING: The formation of cracks in metallic pipe, typically in a colony or cluster, as a result of the interaction of tensile stress, a corrosive environment, and a susceptible material.

STRINGING: The act of laying pipe, end-to-end, alongside the pipeline ditch. in preparation for welding or fusing.

SUBMETERING: The practice of re-metering customer's building meter in order to distribute gas to individual building tenants through privately owned or rented meters.

SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA): A computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

SWEET GAS: Natural gas not contaminated with impurities, such as sulfur compounds. Except for the removal of any liquid constituents that may be present, sweet gas can be used for commercial and domestic use without any processing.

SYMPTOMATIC: Exhibiting symptoms. In relation to this policy, refers to any person that is complaining of or that is outwardly exhibiting symptoms of carbon monoxide related or other illnesses requiring immediate Company response.

SYSTEM: Natural gas facilities that are interconnected and have the same MAOP.

TARIFF: A schedule filled by a utility with a regulatory agency describing transactions between the utility and customers in types of service, rates charged and means of payment.

TASK: A defined unit of work having an identifiable beginning and end and specific actions that are observable and measurable.

TELEMETER: see Telemetry.

TELEMETRY: As related to Avista's gas system, telemetry, in general, is the process of remotely monitoring gas pressure, gas temperature, and calculated values for volume, flow, and abnormal conditions. The values are measured and calculated by instruments at Gate Stations, Regulator Stations, Pressure Monitoring Sites, and Gas Transportation Customers. The instruments also generate alarms/alerts when the values are outside of an acceptable range. They transmit data via cellular modem, dial-up modems, AVA Corporate, or SCADA networks to a server at headquarters which relays the data to the SCADA system, PI data historian system, and Flow Cal system.

TEST MEDIUM: A substance such as water, air, or gas used to exert an internal pressure to leak test or strength test a facility.

TEST POINT: An aboveground electrical connection to an underground pipe or structure where pipe-to-soil potentials are taken to monitor CP. (Also known as a "test station" or a "fink".)

TEST PRESSURE: The internal gauge pressure specified for testing.

THERM: A unit of energy equivalent to 100,000 BTUs. A customer is billed according to the quantity of therms used.

TRACEABLE (RECORDS): Traceable records are those which can be clearly linked to original information about a pipeline segment or facility.

TRANSMISSION LINE: A pipeline or connected series of pipelines, other than a gathering line, that:

1) Transports gas from a gathering pipeline or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;
2) Has an MAOP of 20 percent or more of specified minimum yield strength (SMYS);
3) Transports gas within a storage field; or
4) Is voluntarily designated as a transmission pipeline

TRANSPORTATION CUSTOMER: A gas transportation customer is one who purchases natural gas directly, usually through a broker, and pays Avista a transport fee.

TRENCH: A long ditch cut into the ground dug by a backhoe or by a specialized digging machine such as a trencher, for the purpose of installing a pipeline.

UNION: A specialized threaded fitting used to couple two joints of threaded pipe together, without having to turn or dismantle either run of pipe.

UPPER EXPLOSIVE LIMIT (UEL): The upper explosive limit of natural gas which varies slightly depending on the amount of methane present. For Avista, it is generally defined as 15 percent gas in air. Refer to "Explosive Limits" for more information.

VALVE: A mechanical device used to control the flow of gas or liquid. A valve can be used solely for fully open or closed applications, to control the direction of flow, or used to throttle flow or regulate pressure. Typical valve types include plug valves, ball valves, globe valves and gate valves.

VALVE BOX: A housing around an underground valve that extends to the surface of the ground. A valve box allows access to the valve and protects the valve from mechanical damage or the effects of weather.

VALVE SEAT: The stationary portion of the valve which, when in contact with the movable portion, stops flow completely.

VAULT: An underground pit or enclosed structure which houses valves, pressure regulation equipment, or other gas appurtenances.

VERIFIABLE (RECORDS): Verifiable records are those in which information is confirmed by other complementary, but separate, documentation.

VERIFICATION: The act of checking the accuracy of an instrument or device and making required adjustments if it is found to be out of tolerance. This process is typically done by comparing the device to a recognized standard device that is known to be accurate.

VOLT: The electromotive force which, when steadily applied to a conductor with one ohm resistance, will produce a current of one ampere.

VOLTAGE: An electromotive force or a difference in electrode potentials expressed in volts.

WEAK LINK: A device or method used when pulling polyethylene pipe, typically through methods such as horizontal directional drilling, to ensure that damage will not occur to the pipeline by exceeding the maximum tensile stress allowed.

WELDING: A method of joining metal together using heat to fuse the pieces. Examples of welding processes are shielded metal arc welding and gas metal arc welding.

WET GAS: Natural gas containing liquid, including water or liquefiable hydrocarbons such as natural gasoline, butane, pentane, and other light hydrocarbons that can be removed by chilling, pressurization, or other extraction methods. For operator established tariff purposes, any gas containing water vapor in excess of 7 pounds per million cubic feet (mmcf) is considered wet gas.

WICK-TYPE ODORIZER: Equipment that odorizes the natural gas by having the natural gas flow across a wick in a pipe bottle saturated with odorant. Wick-type odorizers are generally used for odorizing individual lines such as farm taps.

WRINKLE BENDS: Bends made by the obsolete practice of bending prior to the advent of smooth bending technology. See 49 CFR Part 192.3 for a detailed definition of a wrinkle bend. (Wrinkle bends are not allowed at Avista.)

YIELD STRENGTH: The yield strength is the stress level at which a material exceeds its elastic limits, and the material begins to permanently deform.

Subject	Details	Spec/Section	Subsection
1% at 1 foot rule		GESH 4	general
10 ppm Rule	CO orders	GESH 3	10 ppm rule
10% survey of isolated main and risers		5.14	monitoring isolated mains less than 100 ft or service lines; maintenance and remediation timeframes and frequencies
100 ppm Rule	CO orders	GESH 3	100 ppm rule
10-year overhaul of regulator stations		5.12	10 year overhaul - diaphragm type regulators; relief valves & pilots
11000 intermediate pressure meter set	Drawing B-33325, pg 4	2.24	Appendix A
180 day inspection	criteria	5.12	180 day inspection criteria
2 psig meter sets	maintenance	5.12	maintenance of elevated service pressure accounts
2 psig meter sets	design	2.22, 2.24	2.22 industrial sets & elevated pressure sets; 2.24 -Appendix A
20% leak survey		5.11	5 year survey; maintenance frequencies
200 ppm Rule	CO orders	GESH 3	200 ppm rule
2000, 3000, and 3500 intermediate pressure rotary meter	Drawing B-33325, pg 1	2.24	Appendix A
2000, 3000, and 5000 welded rotary meter press	Drawing B-38205	2.24	Appendix A
24-hour rep	restoration of service	GESH 5	steps for restoration of service
250 psig and above pipelines leak surveys		5.11	250+ psig pipelines Washington only; maintenance frequencies
3 Foot Rule	Drawing A-36275	2.22	Drawing A-36275
3 Foot Rule		2.22	3 Foot Rule
35 ppm Rule	CO orders	GESH 3	35 ppm rule
5 psig meter sets	maintenance	5.12	maintenance of elevated service pressure accounts
5 psig meter sets	design	2.22, 2.24	2.22 - industrial sets & elevated pressure sets; 2.24 - Appendix A
5000 and 7000 intermediate pressure rotary meter	Drawing B-33325, pg 2	2.24	Appendix A
5-year overhaul of regulator stations		5.12	5 year overhaul - flexible element & boot type regulators and relief valves
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cathodic protection	test lead color coding diagram	2.32	A-35447
cathodic protection	theory of corrosion	2.32	theory of corrosion
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cathodic protection	shorted casings, leak survey requirement	5.11	special surveys
cathodic protection	casings monitoring	5.14	monitoring steel in steel casings; shorted casings; maintenance and remediation timeframes and frequencies
cathodic protection	copper-copper sulfate half cell	5.14	cathodic protection criteria
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cathodic protection	electrode	5.14	structure-to-electrolye potential (pipe-to soil potential)
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cathodic protection	isolated main less than 100 ft	5.14	monitoring isolated mains less than 100 ft or service lines; maintenance and remediation timeframes and frequencies
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cathodic protection	maintenance	5.14	throughout
cathodic protection	monitoring	5.14	cathodic protection monitoring;
cathodic protection	pipe-to-soil procedure	5.14	structure-to-electrolye potential (pipe-to soil potential)
cathodic protection	recordkeeping	5.14	recordkeeping
cathodic protection	rectifier monitoring	5.14	monitoring rectifiers
cathodic protection	remediation	5.14	maintenance and remediation timeframes and frequencies
cathodic protection	shorted casings, CP remediation	5.14	maintenance and remediation timeframes and frequencies
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cathodic protection	corrosion cell	2.32, 5.14	2.32 - corrosion cell; 5.14 - internal corrosion control
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cathodic protection	rectifier inspection, OQ task	4.31 App A	221.110.050
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cathodic protection (CP)	continuity, maintaining	3.16	steel service replacement
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class locations	SMYS (classes by SMYS)	2.12	class location considerations
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gas equipment service	service to all appliances	GESH 10	service to all appliances
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gas incident field investigation	inspection and testing of meters	GESH 17	inspection and testing of meters
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gas shut-off notice	definition	1.1	glossary

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heat fusion joint	definition	1.1	glossary
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heaters	maintenance, all types	5.22	throughout
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high bill investigation field orders	required information	GESH 16	required information
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high bill investigation field procedures	adjustments	GESH 16	adjustments
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high bill investigation field procedures	customer notification	GESH 16	customer notification
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high occupancy structures	curb valve installation requirements	2.14, 2.22	2.14 - emergency curb valves; 2.22 - identifying sites with special design and maintenance requirements
high occupancy structures	leak survey requirements	2.22, 5.11	2.22 - identifying sites with special design and maintenance requirements; 5.11 - annual surveys
high pressure	definition	1.1	glossary
high pressure alarm	responding to	GESH 13	responding to pressure alarms
high/low gas pressures	priority 1 emergency requests	GESH 1	priority 1 - emergency requests
holiday	definition	1.1	glossary
holiday detector (jeeping machine)	definition	1.1	glossary
hoop stress	definition	1.1	glossary
horizontal directional drilling (HDD)		3.19	horizontal direction drilling
host pipe		3.19	pipe splitting
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hud part 3280	manufactured homes	GESH 12	unvented heaters - manufactured homes
hydraulic butt fusion		3.23	hydraulic butt fusion
hydraulic pressure	fusion pressure table	3.23	hydraulic butt fusion
hydraulic shift sequence	heat fusion	3.23	hydraulic butt fusion
hydrocarbon contamination	heat fusion	3.23	butt fusion troubleshooting guide
hydrofracture		3.19	HDD bore path; HDD discharge mitigation plan
ice covering meter	priority 2 requests	GESH 1	priority 2 requests
Idaho - rule no. 182 (IPUC No 27) "Contingency Plan for Firm Service Gas Curtailment"	emergency operations	GESH 13	curtailment rules
Idaho Code Title 55 Chapter 22; 55-2208 (5)		4.14	ID damage reporting
Idaho dig law website reference		4.13	locating and marking gas facilities
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identify atmospheric corrosion, OQ task		4.31 App A	221.110.020
identify corrosion on buried pipe, OQ task		4.31 App A	221.110.015
idle meter	definition	1.1	glossary
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idle meter	removing	5.16	idle meters and idle services
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ignition temperature	definition	1.1	glossary
illegal meter bypass		GESH 15	typical gas diversion methods
immediate response	definition	1.1	glossary
impressed current	definition	1.1	glossary
impressed current system		2.32	impressed current system
inactivating gas meter facilities		5.16	inactivating gas meter facilities
inches of water column	definition	1.1	glossary
incident	definition	1.1	glossary

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incident investigation	emergencies	GESH 17	throughout
incidental gas leaks		GESH 10	incidental gas leaks
inconclusive	definition	1.1	glossary
inconclusive leaks and odors		5.11, GESH 2	5.11 - leak detection instruments; 5.11 - underground leak investigation; GESH 2 - meter spot check procedure; GESH 2 - underground leak investigation; GESH 2 - inconclusive leak and odor investigation
inconclusive leaks and odors	detection of other combustible gases	GESH 2	detection of other combustible gases
inconclusive leaks and odors	flame Ionization follow up	GESH 2	flame ionization (ppm survey) follow up
incorrect meter number		GESH 9	incorrect meter number
index tampering		GESH 15	typical gas diversion methods
industrial meter set	definition	1.1	glossary
industrial meter sets	maintenance	5.12	general maintence of all service pressures; maintenance of industrial meter sets; maintenance frequencies
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inert gas	definition	1.1	glossary
inflection	definition	1.1	glossary
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inhibitor	definition	1.1	glossary
INHVAC	association	GESH 12	minimum qualifications
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injection rate for purging		3.17	injection rate
injection type odorizer	type	2.52, 5.23	2.52 -odorizer types; 5.23 - injection odorizers (YZ type)
injections, hand gun lubrication		5.13	plug valve lubrication procedures
input rating	definition	1.1	glossary
insertion of PE (polyethylene) pipe into steel services		3.16	insertion of old steel services along plastic main
insertion of steel into steel services		3.16	insertion of old steel services along steel main
inside leak and odor investigation		GESH 2	customer side leak and odor investigation
inside meter sets		2.22	inside meter sets
inspection	welding preparation	3.22	weld preparation
inspection	atmospheric corrosion	5.14	maintenance and remediation timeframes and frequencies; exposed pipe reads; recordkeeping
inspection	bridges	5.15	general; maintenance frequencies
inspection	distribution lines	5.15	general; maintenance frequencies
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inspection	pipeline markers for buried pipe	5.15	pipeline markers for buried pipe

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inspection	transmission lines	5.15	maintenance frequencies
inspection	underwater inspections (major crossings)	5.15	maintenance frequencies; recordkeeping
inspection orders	safety inspection report	GESH 12	safety inspection report
inspection procedures	air tests	GESH 12	air tests
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inspection procedures	customer instructions	GESH 12	customer instructions
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inspection procedures	equipment warranties	GESH 12	equipment warranties
inspection procedures	meter installations	GESH 12	meter installations
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inspection reports, PE		see exposed piping	
inspection reports, steel		see exposed piping	
inspection, general		3.14, 4.13	3.14-throughout; 4.13 - on-site inspections general
inspection, HP distribution pipelines		5.10	line patrols
install gas meters, OQ task		4.31 App A	221.070.041; 221.070.045
installation of meters, erts and regulators	back pressure protection	GESH 6	back pressure protection
installation of meters, erts and regulators	high pressure meter sets	GESH 6	high pressure meter sets
installation of meters, erts and regulators	installing bypasses	GESH 6	installing bypasses
installation of meters, erts and regulators	insulating meter sets	GESH 6	insulating meter sets
installation of meters, erts and regulators	leveling	GESH 6	leveling
installation of meters, erts and regulators	marking of multiple meters	GESH 6	marking of multiple meters
installation of meters, erts and regulators	meter, ert configurations	GESH 6	meter, ert configurations
installation of meters, erts and regulators	meter, ert, and regulator install	GESH 6	meter, ert, and regulator install
installation of meters, erts and regulators	pipe-joining	GESH 6	pipe-joining
installation of meters, erts and regulators	pre-installation procedure	GESH 6	pre-installation procedure
installation of meters, erts and regulators	regulator replacements	GESH 6	regulator replacements
installation of meters, erts and regulators	supporting manifolds	GESH 6	supporting manifolds
installation of meters, erts and regulators	vents	GESH 6	vents
installation test procedures	locking and unlocking meters	GESH 6	locking and unlocking meters
installation test procedures	meter test	GESH 6	meter test
installation test procedures	meter-set leak test	GESH 6	meter-set leak test
installation test procedures	odorant test	GESH 6	odorant test
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insulation	cathodic protection	2.32	insulation
insulator	definition	1.1	glossary
intermediate pressure	definition	1.1	glossary
intermediate pressure meter set	Drawing A-35208	2.24	Appendix A
intermittent ignition (IID)	definition	1.1	glossary
internal corrosion control		5.14	internal corrosion control
internal relief valve (IRV)	definition	1.1	glossary
international fuel gas code	safety inspections	GESH 12	recognized codes
international mechanical code	safety inspections	GESH 12	recognized codes
interruptible gas	definition	1.1	glossary
investigation		see incident invest.	
iron case meters	meters	2.22	meter types
iron temperature (fusion)		3.23	heating tool
isolated main less than 100 ft		5.14	monitoring isolated mains less than 100 ft or service lines; maintenance and remediation timeframes and frequencies
isolated risers	without CP, (leak survey)	5.11	maintenance frequencies

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isolated risers		5.14	throughout
isolated services		5.14	isolated services
isolated steel		4.14, 5.14	4.14 - wa isolated steel and replacement program; 5.14 - monitoring isolated main less than 100 ft or service lines; 5.14 - isolated steel; 5.14 - isolated steel risers; 5.14 - isolated steel services; 5.14 - maintenance and remediation timeframes and frequencies
jeep	definition	1.1	glossary
jeeping	steel pipe	3.12	electrical inspection of pipeline coatings (jeeping)
jeeping	formula	3.12	voltage settings for thin film coatings
jeeping	formula	3.12	voltage settings for conventional coatings
joining	steel pipe	3.22	throughout
joining	PE pipe	2.13, 3.23, 3.24, 3.25	2.13 - joining of plastic pipe components; 3.23 - throughout; 3.24 - throughout; 3.25 - throughout
joint ditch design	pre-check layout and inspection	3.14	joint ditch
joint ditch design		see trenching	
joule-thomas effect	definition	1.1	glossary
joule-thomson effect		5.22	general
knitted fiberglass tape	ARO for steel pipe in HDD work	3.12	knitted fiberglass tape
ladder policy	definition	1.1	glossary
landfill gas	definition	1.1	glossary
large diaphragm meter set drawing	Drawing C-35209	2.24	Appendix A
lateral	definition	1.1	glossary
leak	definition	1.1	glossary
leak and odor investigation	general	GESH 2	general
leak and odor investigation	required information	GESH 2	general
leak and odor investigation	responding employee qualifications	GESH 2	general
leak centering or pinpointing	definition	1.1	glossary
leak check	high pressure	3.18	pressure testing for steel
leak detector	definition	1.1	glossary
leak failure cause definitions		5.11, GESH 2	5.11 - leak failure cause definitions; GESH - 2 leak failure cause definitions
leak investigation		5.11, GESH 2	5.11 - leak detection instruments; 5.11 - detection of other combustible gases; 5.11 - grade 1 leak; 5.11 - underground leak investigation; 5.11 - underground leak determination; 5.11 - leak repair and residual gas checks; 5.11 - follow up inspections for residual gas; GESH 2 - throughout
leak investigation	can't gain entry procedures	GESH 2	can't gain entry procedures

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leak survey	250 psig and greater pipelines	5.11	250+ psig pipelines Washington only; maintenance frequencies
leak survey	5 year surveys	5.11	5 year survey; maintenance frequencies
leak survey	annual surveys	5.11	annual surveys; maintenance frequencies
leak survey	barholes	5.11	underground leak determination
leak survey	bubble leak tests	5.11	bubble leak test
leak survey	buildings of public assembly	5.11	annual surveys
leak survey	business districts	5.11	annual surveys; maintenance frequencies
leak survey	calibration of equipment	5.11	leak detection instruments; maintenance of instruments
leak survey	classifying leaks	5.11	classifying leaks
leak survey	combustible gas indicator (CGI)	5.11	leak detection instruments; classifying leaks; pinpointing/centering; underground leak repair; recordkeeping and reporting
leak survey	detecto-pak infrared detector (DP-IR)	5.11	leak detection instruments
leak survey	DIMP identified surveys	5.11	DIMP identified surveys
leak survey	ejector aerator	5.11	pinpointing / centering
leak survey	failure causes	5.11	leak failure cause definitions
leak survey	flame ionization detector (F.I.)	5.11	leak detection instruments; surface gas detection survey; survey limitations; annual surveys; transmission pipelines; 5 year survey; special survey
leak survey	grade 1 leaks	5.11	grade 1 leaks
leak survey	grade 2 leaks and grade 2A leaks	5.11	grade 2A leak; grade 2 leak
leak survey	grade 3 leaks	5.11	grade 3 leaks
leak survey	high pressure mains, 250+ psig, WA	5.11	250+ psig pipelines Washington only; maintenance frequencies
leak survey	IRed	5.11	leak detection instruments
leak survey	lowered pipelines	5.11	special surveys
leak survey	maintenance of instruments	5.11	maintenance of instruments
leak survey	mechanical fittings	5.11	leak failure cause definitions; hazardous mech. fitting failures
leak survey	methods	5.11	gas leak survey methods
leak survey	paving, prior to	5.11	special surveys
leak survey	pressure drop test	5.11	pressure drop test
leak survey	procedures	5.11	throughout
leak survey	re-classification of leaks	5.11	re-classification of leaks
leak survey	recordkeeping	5.11	recordkeeping and reporting
leak survey	remote methane leak detector (RMLD)	5.11	leak detection instruments
leak survey	self-audits	5.11	self-audits
leak survey	special surveys	5.11	special surveys
leak survey	surface gas detection methods	5.11	surface gas detection survey
leak survey	transmission pipelines	5.11	transmission and other HP pipelines; maintenance frequencies

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leak survey	cathodic protection	5.14	shorted casings; isolated steel; maintenance and remediation timeframes and frequencies
leak survey	OQ task	4.31 App A	221.230.005
leak survey	pinpointing/centering	5.11, GESH 2	5.11 - pinpointing / centering; GESH 2 - pinpointing / centering
leak test	definition	1.1	glossary
LEL		4.18, 5.11, 5.19, GESH 2, GESH 4	4.18 - odorant concentrations; 5.11 - grade 1 leak; 5.11 - grade 2A leaks; 5.11 - grade 2 leak; 5.11 - grade 3 leak; 5.19; GESH 2 - grade 1 leak; GESH 2 - grade 2 leak; GESH 2 - grade 3 leak; GESH 4 - evacuation procedures
leveling		GESH 6	leveling
lift of pipe	definition	1.1	glossary
lighting strike / electric arcing field checklist		GESH 17	lightning strike / electric arcing field checklist
limit device	definition	1.1	glossary
line heaters		5.22	line heaters
line patrols		5.15	maintenance frequencies; recordkeeping
line tamer	heat fusion	3.23	cold weather fusion
link type seals		3.42	installing steel carrier pipe in casing
liqueified natural gas	definition	1.1	glossary
liquid epoxy coating	steel pipe	3.12	liquid epoxy coating
little fink	installation drawing B-34947	3.42	B-34947
little fink	installing leads & stations, OQ task	4.31 App A	221.110.035
load	definition	1.1	glossary
local distribution company (LDC)	definition	1.1	glossary
locate wire	steel pipe	3.19	future locatability
locating facilities	emergency locates	4.13	requesting emergency locates
locating facilities		4.13	locating and marking gas facilities
locating facilities	OQ task	4.31 App A	221.230.050
locks	regulator station locks	5.12	general station inspection
locks	relief valve locks	5.12	general station inspection
locks	valve locks	2.14, 2.23, 3.16, 5.12, 5.13, 5.16	2.23 - valve; 3.16 - new service lines not in use; 5.12 - general station inspection; 5.13 - general valve maintenance and installation notes; 5.16 - idle meters and idle services
locks	idle riser locks	2.22, 5.16	2.22 - idle services; 5.16 - idle meters and idle services
locks	gas meter locks	2.22, 5.16, 5.17, GESH 1, 2, 3, 5, 6, 7, 8, 9, 10, 12, 15, 17	5.16 - inactivating gas meter facilities; 5.17 - reinstating gas facilities; GESH 1 - handling fire department calls; GESH 2 - procedures upon entry; GESH 2 - hazardous conditions; GESH 2 - can't gain entry procedures; GESH 3 - initial determination; GESH 5 - maps and lists; GESH 5 - restoring service; GESH 5 - meters turned on by other than avista; GESH 5 - can't gain entry situations; GESH 5 - steps for restoration of service

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longitudinal stress	steel pipe (design formula)	2.12	longitudinal stress
low pressure	definition	1.1	glossary
low pressure alarm	responding to	GESH 13	responding to pressure alarms
low pressure situations	monitoring pressures	GESH 5	monitoring pressures
low pressure situations	plan of action	GESH 5	plan of action
low pressure situations	pressure drops	GESH 5	pressure drops
lower explosive limit (LEL)	definition	1.1	glossary
lowering steel pipe	decision flow chart	3.12	steel pipe lowering decision flowchart
lowering steel pipe	minimum considerations	3.12	moving or lowering steel pipe in service
lowering steel pipe	Washington State study requirements	3.12	toughness testing
lowering steel pipe	leak survey after	3.12, 5.11	3.12 - toughness testing; 5.11 - special surveys; 5.11 - maintenance frequencies
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lycoring		3.25	procedure for installing approved spigot and sleeve type couplings and fittings using the QRP-100 quick ratchet press tool; procedure for installing approved spigot and sleeve type couplings and fittings using the lhp-200 hydraulic press tool
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maintenance cycles	joining certification, PE joining	3.23	pipe joining certification record
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maintenance cycles	EOP plan	5.11	grade 1 leak
maintenance cycles	FI (flame ionization) units	5.11	maintenance of instruments
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maintenance cycles	regulator stations	5.12	maintenance frequencies
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maintenance cycles	pressure gauge calibrations	5.21	maintenance frequencies
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MAOP (maximum allowable operating press.)	determination of	4.15	determination of MAOP
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meter room	minimum requirements for	2.22	avista's requirements for meter room installations
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meter set	design	2.22	avista's requirement for gas meter room installations
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meter spot check	procedures	GESH 2	avista side leak and odor investigation
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metering pressure	definition	1.1	glossary
meters	10 foot rule	2.22	10 foot rule
meters	2 psig meter sets	2.22	industrial sets & elevated pressure sets
meters	3 foot rule	2.22	3 foot rule
meters	5 psig meter sets (under elevated sets)	2.22	industrial sets & elevated pressure sets
meters	alcove installation	2.22	alcove installation
meters	aluminum	2.22	meter types
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meters	atmospheric pressure table	2.22	elevation compensation
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meters	clearances	2.22	3 foot rule; 10 foot rule
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meters	elevated pressure sets	2.22	industrial sets & elevated pressure sets
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meters	meter rooms	2.22	meter set location protection and barricades; meter room installation; avista's requirements for gas meter room
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meters	multiple services	2.22	multiple services
meters	PP&L territory location rule	2.22	3 foot rule
meters	pressure compensation	2.22	pressure compensation
meters	prover calibrations	2.22	prover calibration interval
meters	regulator design	2.22	throughout
meters	relief vent design	2.22	avista's requirements for meter room installations
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meters	special design and maintanence requirements	2.22	inside meter sets
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meters	temperature corrected flows	2.22	computing corrected flows
meters	testing frequency	2.22	frequency of meter tests
meters	turbine meters	2.22	meter types
meters	types	2.22	meter types
meters	vault	2.22	pits and vaults
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meters	coriolis meters	2.22	meter types
meters	protection	2.22	meter set location, protection, and barricades
meters	barricades	2.22	meter set location, protection, and barricades
meters	downstream insulation	2.22	insulating downstream customer piping
meters	capacity tables	2.24	meter capacity tables
meters	diaphragm type capacity table	2.24	diaphragm meters
meters	drawings, standard	2.24	Appendix A
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meters	standard drawings	2.24	Appendix A
meters	tables for sizing	2.24	meter capacity tables
meters	turbine type capacity table	2.24	meter capacity tables
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meters	design	2.22, 2.24, GESH 6	2.22 - throughout; 2.24 - throughout; GESH 6 - meter and regulator design
meters	installation	2.22, 2.24, GESH 6	2.22 - installation; 2.24 - throughout; GESH 6 -

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meters	overbuilds	2.22, 5.20	2.22 - overbuilds; 5.20 - inspection requirements
meters	insulating	2.22, GESH 6	2.22 - Insulating downstream customer piping; GESH 6 - insulating meter sets
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mil	definition	1.1	glossary
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minimum safe utilization pressure	definition	1.1	glossary
miter joint	definition	1.1	glossary
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monitor regulator	testing	5.12	maintenance of overpressure protection devices; monitor testing
monitoring pressure		3.12, 3.13, 3.32, 3.33, 4.31 App A, 5.12	3.12 - monitoring of pressures; 3.13 - monitoring of pressures; 3.32 monitoring of pressure; 3.33 monitoring of pressure; 4.31 App A - 221.230.035; 5.12 - pressures precaution
Mueller	Save-a-Valve nipple	3.32	mueller save-a valve nipple or equivalent; steel repair selection charts

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Mueller	tapping & stopping 6" and larger	4.31 App A	221.040.010
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national transportation safety board (NTSB)	definition	1.1	glossary
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natural gas	definition	1.1	glossary
natural gas	behavior of	2.22	behavior of natural gas
natural gas	corrected flows	2.22	computing corrected flows
natural gas	volume calculation	2.22	gas volume calculation
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neutral pressure point	definition	1.1	glossary
new construction riser	definition	1.1	glossary
new plastic services	tracer wire corrosion prevention	3.16	new plactic services
nfpa number 54		GESH 12	recognized codes; unvented heaters and decorative appliances; boilers
nitrogen	purging with	3.17	purging with nitrogen
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nitrogen	relief testing with nitrogen, procedure	5.12	relief and safety shut-off testing; procedure for testing relief valves with nitrogen or bottled cng
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northwest energy code, the	safety inspections	GESH 12	recognized codes
Nucleus	data collection	2.25	data path and uses
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odorization	recordkeeping	4.18	recordkeeping
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odorization	periodic sampling (testing) , OQ task	4.31 App A	221.090.030
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odorizer	maintenance	4.31 App A, 5.23	4.31 App A - 221.090.025; 5.23 - injection odorizers (YZ type); 5.23 - by-pass odorizers; 5.23 - wick odorizers
odorizers	types	2.52	odorizer types
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on-site inspections	damage prevention	4.13	throughout
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Oregon - rule no. 14 - "continuity of service"	emergency operations	GESH 13	curtailment rules
Oregon dig law website reference		4.13	locating and marking gas facilities
Oregon state OAR by number	860-021-0130	GESH 16	customer requested meter test
orifice	definition	1.1	glossary
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p/s (pipe to soil)	definition	1.1	glossary
padding	definition	1.1	glossary
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relief	annual capacity review	5.12	district regulator station relief capacity review; gage station regulator and relief set point review
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sleeving	definition	1.1	glossary
sleeving		3.32	sleeving
slip-lock type couplings		3.25	procedure for installing approved slip lock type couplings and fittings (reference ECN 2185 Rev "L" 10/31/07, 34-6034-00; procedure for installing approved bolt-on type mechanical tees with slip-lock type outlet connection (reference: ECN 2185 Rev "L" 10/31/07, 34-6034-02
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SSFT maintenance		5.12	farm taps; general station inspection; farm taps and HP services; 10 year overhaul - diaphragm type regulators, relief valves & pilots; maintenance frequencies
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static charges		3.13, 3.17, 3.33, 3.34	3.13 - static charges; 3.17 purging plan; 3.17- static charges; 3.33 - static charges, 3.34 - prevention of accidental ignition by static electricity; 3.34 - prevention of static electricity procedures
static electricity	definition	1.1	glossary
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steel pipe	design of pipeline components	2.12	design of pipeline components
steel pipe	design tables (steel pipeline data)	2.12	steel pipe data tables
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steel pipe	corrosion protection	2.12	corrosion protection
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steel pipe	lowering decision flowchart	3.12	steel pipe lowering decision flowchart
steel pipe	ARO coating of	3.12	liquid epoxy coating
steel pipe	coating, thin film	3.12	voltage settings for thin film coatings (FBE)
steel pipe	cold applied tape wrap	3.12	tape wrap
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steel pipe	FBE coating	3.12	tape wrap; voltage settings for thin film coatings (FBE); voltage settings for ARO pipe
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steel pipe	non-destructive testing (NDT)	3.12	visual inspection
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temporary control of escaping gas	broken steel pipe	GESH 4	standard methods of control (60 psig or less)
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temporary control of escaping gas	hp control	GESH 4	HP control
temporary control of escaping gas	media inquiries	GESH 4	media inquiries
temporary control of escaping gas	standard methods of control (60 psig or less)	GESH 4	standard methods of control (60 psig or less)
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transmission line	change approvals	2.12	transmission line - approval of change
transmission line	valves	2.14	transmission line valves
transmission line	repairs	3.32	transmission lines
transmission line	inspection	4.13	on site inspections for transmission facilities
transmission line	leak survey	5.11	transmission and other HP pipelines; maintenance frequencies
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upper explosive limit (UEL)	definition	1.1	glossary
uprating	hoop stress	4.17	uprating pipeline to hoop stress < 30 percent smys; uprating pipeline to hoop stress => 30 percent smys
uprating	incremental pressure increases	4.17	uprating requirements, uprating pipeline to hoop stress < 30 percent smys
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uprating	pipe record form	4.17	avista utilties system uprate area pipe record
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uprating	repairs	4.17	uprating requirements; uprating pipeline to hoop stress < 30 percent smys; recordkeeping; uprating procedure - typical sequence of events; avista utilties written plan for pressure uprating; uprate procedure & history
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valve seat	definition	1.1	glossary
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valves	mainline	2.14	installation
valves	new housing developments	2.14	valves at new housing developments
valves	supports	2.14	valve supports
valves	transmission line	2.14	transmission line valves
valves	numbering	2.14	valve numbering
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valves	gate, steel	2.14	steel gate valves
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valves	PE (polyethylene)	2.14	polyethylene valves
valves	service line	2.14	service line valves
valves	curb	2.14	curb valves (underground service valves)
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valves	earthquake (meters)	2.22	earthquake valves
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valves	gear valves	5.13	steel gear valves; gear valves
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valves	polyethylene	2.14, 5.13	2.14 - valve types; 5.13 - poly valves
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valves	replace service valves	4.31 App A	221.050.005
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valves	boxes	5.13, 5.16	5.13 - maintaining valve boxes; 5.13 - maintenance frequencies - valves; 5.16 - valve box abandonment
vault	definition	1.1	glossary
vaults	meter vaults	2.22	pits & vaults
vaults	design	2.42	throughout
vaults	drainage	2.42	drainage
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vaults	sealing	2.42	sealing and ventilation
vaults	size-related rules	2.42	sealing and ventilation
vaults	ventilation	2.42	sealing and ventilation
vaults	steel pipe installation within	3.12	pits and vaults
vaults	abandonment	5.16	vault abandonment
vaults	inspection	5.18	vault inspection
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verification	definition	1.1	glossary
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voltage	definition	1.1	glossary
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Washington State WACs by description	reporting of transmission construction	2.12	reporting of proposed construction of transmission main
Washington State WACs by description	transmission line construction	2.12	reporting of proposed construction of transmission main
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Washington State WACs by description	maximum time limit for temp PE	2.13	above ground plastic pipe
Washington State WACs by description	PE pipe above ground	2.13	above ground plastic pipe
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Washington State WACs by description	incident reporting	4.11	material failure
Washington State WACs by description	mapping updates	4.11	map and data corrections
Washington State WACs by description	records availability to personnel	4.11	map and data corrections
Washington State WACs by description	updating maps within 6 months	4.11	map and data corrections
Washington State WACs by description	excavation without locate, transmission line	4.13	excavation identified without a locate (WA transmission)
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Washington State WACs by description	damage reporting	4.14	WA damage reporting
Washington State WACs by description	uprating	4.17	uprate in state of Washington
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Washington State WACs by description	proximity considerations	2.12, 2.23, 4.15	2.12 - WA state proximity considerations; 2.23 - regulation of high pressure to service pressure; 4.15 - determination of MAOP
Washington State WACs by description	curb valves criteria	2.14, 5.13	2.14 - emergency curb valves; 5.13 - maintenance frequencies - valves
Washington State WACs by description	emergency curb valves criteria	2.14, 5.13	2.14 - emergency curb valves; 5.13 - maintenance frequencies - valves
Washington State WACs by description	lowering steel pipe	3.12, 5.11	3.12 - toughness testing; 5.11 - special surveys
Washington State WACs by description	material failure report submission	4.11, 5.11	4.11 - material failure; 5.11 - leak failure cause definitions

Subject	Details	Spec/Section	Subsection
Washington State WACs by description	leak survey for pipelines lacking CP	5.11, 5.14	5.11 - special surveys; 5.14-isolated steel
Washington State WACs by description	foreign source leak detection	5.11, GESH 2	5.11 - detection of other combustible gases; GESH 2 - detection of other combustible gases
Washington State WACs by description	emergency contact notification	GESH 13	communication with public officials
Washington State WACs by description	exceeding MAOP	GESH 13	official incident notification
Washington State WACs by number	480-93-017	1.4	construction procedures filing with the WUTC
Washington State WACs by number	480-93-020	2.12	WA state proximity considerations
Washington State WACs by number	480-93-160	2.12	reporting of proposed construction of transmission main
Washington State WACs by number	480-93-178 (6)	2.13	above ground plastic pipe
Washington State WACs by number	480-93-100	2.14	emergency curb valves
Washington State WACs by number	480-93-140 (1)	2.22	general
Washington State WACs by number	480-90-328	2.22	meter identification
Washington State WACs by number	480-90-323	2.22	meter set location, protection, and barricades
Washington State WACs by number	480-93-020	2.23	regulation of high presure to service pressure
Washington State WACs by number	173-160-456 (2)	2.32	design and installation
Washington State WACs by number	480-93-110	2.32	design and installation
Washington State WACs by number	480-93-018	3.12	updating maps and records
Washington State WACs by number	480-93-175	3.12	toughness testing
Washington State WACs by number	480-93-018	3.13	updating maps and records
Washington State WACs by number	480-93-170	3.18	notification to Washington UTC prior to pressure testing transmission pipelines
Washington State WACs by number	480-93-080	3.23	qualifications of persons to join plastic pipe
Washington State WACs by number	480-93-178	3.34	squeezing procedure
Washington State WACs by number	480-93-115	3.42	general, installation requirements
Washington State WACs by number	480-93-018	4.11	map and data corrections
Washington State WACs by number	480-93-200 (9)	4.13	excavation identified without a locate (WA transmission)
Washington State WACs by number	480-93-200 (8)	4.13	WA excavator notifications
Washington State WACs by number	480-93-200 (7)	4.13	WA damage reporting
Washington State WACs by number	480-93-180 (2)	4.14	plans and procedures
Washington State WACs by number	480-93-200	4.14	regulatory requirements
Washington State WACs by number	480-93-200 (10) (b)	4.14	WUTC construction defects & material failures report
Washington State WACs by number	480-93-200 (13)	4.14	DOT drug and alcohol MIS form submission
Washington State WACs by number	480-93-200 (7) (a)	4.14	WA damage reporting
Washington State WACs by number	480-93-200 (7) (c)	4.14	document retention
Washington State WACs by number	480-93-200 (7)	4.14	WA damage reporting
Washington State WACs by number	480-93-155	4.17	uprate in state of Washington
Washington State WACs by number	480-93-200 (12)	4.19	WUTC contact
Washington State WACs by number	480-93-188	5.11	250+ psig pipelines Washington only
Washington State WACs by number	480-93-188 (6)	5.11	self audits
Washington State WACs by number	480-93-185	5.11	detection of other combustible gases
Washington State WACs by number	480-93-188 (3)(d)	5.11	special surveys
Washington State WACs by number	480-93-175	5.11	special surveys

Subject	Details	Spec/Section	Subsection
welding	branch	3.22	qualification of welders
welding	butt	3.22	qualification of welders
welding	certification card	3.22	welder certification card
welding	circumferential weld separation	3.22	circumferential weld separation
welding	defects	3.22	removal or repair of weld defects or cracks
welding	destructive testing	3.22	welder qualification requirements
welding	electrode selection	3.22	throughout
welding	electrode storage	3.22	electrode storage
welding	fillet welding	3.22	fillet welding
welding	gas metal arc (GMAW)	3.22	welding control requirements
welding	grounding devices	3.22	grounding devices
welding	hot pass	3.22	visual inspection
welding	initial qualification test	3.22	qualification of welders
welding	inspection of the weld	3.22	visual inspection
welding	miter joints	3.22	miter joints
welding	non-destructive testing (NDT) requirements	3.22	non-destructive testing (NDT) requirements
welding	over-cooling	3.22	over-cooling
welding	porosity	3.22	visual inspection
welding	preheating	3.22	preheating
welding	pre-inspection	3.22	non-destructive pre-inspection
welding	procedure qualification record (PQR)	3.22	weld procedure qualification requirements
welding	qualification of procedures	3.22	qualification of welders
welding	qualification of welders	3.22	general; qualification of welders
welding	repair	3.22	removal or repair of weld defects or cracks
welding	re-qualification test	3.22	qualification of welders
welding	roll welding	3.22	roll welding
welding	root bead	3.22	depositing root bead and hot pass
welding	shielded metal arc (SMAW)	3.22	throughout
welding	shielding flux	3.22	weld procedure qualification
welding	slag inclusions	3.22	visual inspection
welding	socket welding	3.22	socket welding
welding	speed of travel	3.22	determining speed of travel
welding	strip capping	3.22	filler and cover passes
welding	undercutting	3.22	filler and cover passes, visual inspection
welding	failure cause (leaks)	5.11	leak failure cause definitions
welding	leak failure cause	5.11	leak failure cause definitions
welding	cadwelding	3.12, 3.13, 3.16, 3.22	3.12 - cadweld procedure; 3.13 - tracer wire; 3.16 - insertion of old steel services along steel main; 3.22 - non-destructive pre-inspection
welding	visual inspection of	3.12, 3.22, 4.31 App A	3.12 - visual inspection; 3.22 non-destructive testing (NDT) requirements; 3.22 - visual inspection; 4.31 App A - 221.130.010
welding	procedures, specific	3.22 App A	3.22 App A
welding	procedures	3.22, App A	Appendix A
welding	field welding	3.32A	field welding instructions
welding	seal welding	3.32A	field welding instructions; welding sequence
welding	OQ task	4.31 App A	221.130.010
welds, leak failure cause		GESH 2	leak failure cause definitions

1.3 GAS ACRONYMS AND ABBREVIATIONS

SCOPE:

To define common acronyms and abbreviations found in the natural gas industry.

REGULATORY REQUIREMENTS:

None.

Acronym	Definition of Acronym or Abbreviation
AC	Alternating Current
AC	Atmospheric Corrosion
ACFH	Actual Cubic Feet per Hour
A-D	Analog to Digital
AES	AutoSol Enterprise Service
AFM	Avista Facility Management
AFUDC	Allowance for Funds Used During Construction
AGA	American Gas Association
AGM	Aboveground Markers
AH	After Hours
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ANPRM	Advanced Notice of Proposed Rulemaking
ANSI	American National Standards Institute
AOC	Abnormal Operating Condition
AOC	Area of Concern
APGA	American Public Gas Association
API	American Petroleum Institute

Acronym	Definition of Acronym or Abbreviation
APWA	American Public Works Association
ARCOS	Automated Roster Call-out System
ARO	Abrasion Resistant Overlay
ASME	American Society of Mechanical Engineers
ASNT	American Society of Non-Destructive Testing
ASTM	American Society for Testing and Materials
ASV	Automatic Shut-off Valve
AVA	Avista
AWG	American Wire Gauge
AWS	American Welding Society
BAP	Baseline Assessment Plan
BCF	Billion Cubic Feet
BECS	Building Energy Codes and Standards
BH	Regular Business Hours
BMP	Best Management Practices
BTU	British Thermal Unit
BTUH	British Thermal Unit per Hour
CABO	Council of American Building Officials
CC&B	Customer Care and Billing
CCB	Cathodic Critical Bond
CCF	One hundred cubic feet (of gas)
CDA	Confirmatory Direct Assessment
CDF	Controlled Density Fill
CDR	Construction Design Representative

Acronym	Definition of Acronym or Abbreviation
CDT	Construction Design Tool
CESCL	Certified Erosion & Sediment Control Lead
CF	Can't Find
CF	Cubic Feet
CFH	Cubic Feet per Hour
CFM	Cubic Feet per Minute
CFR	Code of Federal Regulations
CFS	Cubic Feet Per Second
CGA	Canadian Gas Association
CGE	Can't Gain Entry
CGI	Combustible Gas Indicator
CIS	Close-Interval Survey
CLB	Comfort Level Billing
CLM	Construction List Manager
CNG	Compressed Natural Gas
CO	Carbon Monoxide
COS	Cost of Service
CO2	Carbon Dioxide
CP	Cathodic Protection
CPC	Customer Project Coordinator
CSR	Customer Service Representative
CSS	Customer Service System
CSST	Corrugated Stainless Steel Tubing
CTS	Copper Tube Size

Acronym	Definition of Acronym or Abbreviation
CUFT	Cubic Feet (usually shown in lowercase.)
CWAP	Cold Weather Action Plan
CWIP	Construction Work in Progress
DA	Direct Assessment
DBF	Dandy Blue Flame
DC	Direct Current
DCVG	Direct Current Voltage Gradient
DEG	Degrees
DEQ	Department of Environmental Quality
DER	Designated Employer Representative
DHS	Department of Homeland Security
DIMP	Distribution Integrity Management Program
DIRT	Damage Information Reporting Tool
DOE	Department of Energy
DOT	Department of Transportation
DP-IR	Detecto Pak Infrared Detector
DSAW	Double Submerged Arc Weld
DSM	Demand-Side Management
EC	External Corrosion
ECDA	External Corrosion Direct Assessment
EFV	Excess Flow Valve
ELE	Electric
EOP	Emergency Operating Procedure or Emergency Operating Plan
EPA	Environmental Protection Agency

Acronym	**Definition of Acronym or Abbreviation**
ERT	Encoder Receiver Transmitter
ERW	Electric Resistance Welded
ESC	Erosion and Sediment Control Plan
F	Fahrenheit
F/O	Fiber Optic
F.P.	Fireplace
FAF	Forced Air Furnace
FBE	Fusion Bonded Epoxy
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FI	Flame Ionization
FT	Foot or Feet (usually shown in lowercase.)
FVR	Field Verification Report
FW	Flash Weld
G	Grams (usually shown in lower case)
GAAP	Generally Accepted Accounting Principles
GESH	Gas Emergency & Service Handbook
GHG	Greenhouse Gas
GIS	Geographic Information System
GMAW	Gas Metal Arc Welding
GPG	Gas Pressure Gauge
GPR	Ground Penetrating Radar
GPS	Global Positioning System
GPTC	Gas Piping Technology Committee

Acronym	Definition of Acronym or Abbreviation
GSM	Gas Standards Manual
GTI	Gas Technology Institute
GTN	Gas Transmission Northwest
HBI	High Bill Investigation
HCA	High Consequence Areas
HDB	Hydrostatic Design Basis
HDD	Horizontal Directional Drilling
HOA	High Occupancy Area
HOS	High Occupancy Structure
HOS	Hours of Service
HP	High Pressure
HPS	High Pressure Service
HSI	Hot Surface Igniter
HVAC	Heating, Ventilation and Air Conditioning
HVAC	High Voltage Alternating Current
HWH	Hot Water Heater
IC	Internal Corrosion
ICDA	Internal Corrosion Direct Assessment
ICS	Incident Command System
ID	Inside Diameter
IHO	Intended for Human Occupancy
ILI	In Line Inspection
IMP	Integrity Management Plan (or Integrity Management Program)
IN	Inch or Inches (usually shown in lowercase)

Acronym	Definition of Acronym or Abbreviation
INGAA	Interstate Natural Gas Association of America
IOU	Investor Owned Utility
IP	Internet Protocol
IPM	Incident Prevention Manual (Safety Manual)
IPS	Iron Pipe Size
IPUC	Idaho Public Utility Commission
IRAS	Integrated Risk Assessment Software
IRED	Infrared Ethane Detector
IRP	Integrated Resource Plan
IRV	Internal Relief Valve
IT	Information Technology
IUCC	Idaho Utility Coordinating Council
IVP	Integrity Verification Process
IVR	Interactive Voice Response
JPSP	Jackson Prairie Storage Project
KFGS	Kettle Falls Generating Station
LB	Pound or Pounds (usually shown in lowercase.)
LCD	Liquid Crystal Display
LDC	Local Distribution Company
LEL	Lower Explosive Level
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LTIR	Lost Time Injury Rate
MAOP	Maximum Allowable Operating Pressure

Acronym	Definition of Acronym or Abbreviation
MCA	Moderate Consequence Areas
MCF	One Thousand Cubic Feet
MDM	Meter Data Management
MDQ	Maximum Daily Quantity
MDT	Marketing Design Technician
MEA	Midwest Energy Association
MIC	Microbiologically Induced Corrosion
MIS	Management Information System
MMBTU	One Million British Thermal Units
MMCF	One Million Cubic Feet
MOC	Management of Change
MOP	Maximum Operating Pressure
MRO	Medical Review Officer
MSA	Meter Set Assembly
MSDS	Material Safety Data Sheet
MSS	Manufacturers Standardization Society
MTR	Mill Test Report
NACE	National Association of Corrosion Engineers
NAPSR	National Association of Pipeline Safety Representatives
NARUC	National Association of Regulatory Utility Commissioners
NDE	Non-Destructive Evaluation
NDT	Non-Destructive Testing
NEC	National Electric Code
NFPA	National Fire Protection Association

Acronym	Definition of Acronym or Abbreviation
NG	Natural Gas
NGL	Natural Gas Liquids
NGT	Not Greater Than
NGV	Natural Gas Vehicle
NLT	Not Less Than
NO	Non-Observable
NOA	Notice of Amendment
NOAA	National Oceanic and Atmospheric Administration
NOI	Notice of Intent
NOP	Nominal Operating Pressure
NOPR	Notice of Proposed Rulemaking
NOPV	Notice of Probable Violation
NOT	Notice of Termination
NPDES	National Pollutant Discharge Elimination System
NPMS	National Pipeline Mapping System
NPRM	Notice of Proposed Rulemaking
NPS	Nominal Pipe Size
NPT	National Pipe Thread
NRC	National Response Center
NTE	Not to Exceed
NTSB	National Transportation Safety Board
NWP	Northwest Pipeline (i.e., Williams Northwest Pipeline Company)
O&M	Operation and Maintenance
OAR	Oregon Administrative Rules

Acronym	Definition of Acronym or Abbreviation
OCS	Outer Continental Shelf
OD	Outside Diameter
ODEQ	Oregon State Department of Environmental Quality
OMB	Office of Management and Budget
OOF	Other Outside Forces
OPID	Operator Identification Number
OPP	Overpressure Protection
OPS	Office of Pipeline Safety
OPUC	Oregon Public Utilities Commission
OQ	Operator Qualification
OSHA	Occupational Safety and Health Administration
OSRAC	Operations Safety Regulatory Action Committee
OST	Office of the Secretary of Transportation
P&M	Preventive and Mitigative
PAPA	Pipeline Association for Public Awareness
PAW	Pipeline Association of Washington
PE	Polyethylene
PEF	Performance Evaluation Form
PGA	Purchase Gas Adjustment
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIC	Potential Impact Circle
PIR	Potential Impact Radius
PLC	Programmable Logic Controller
PMC	Periodic Meter Change-Out Program

Acronym	Definition of Acronym or Abbreviation
PPB	Parts per Billion (usually shown lowercase)
PPDC	Plastic Pipe Data Collection (AGA)
PPE	Personal Protective Equipment
PPI	Plastic Pipe Institute
PPM	Parts per Million (usually shown lowercase)
PPV	Peak Particle Velocity
PQR	Procedure Qualification Record
PSI	Pounds per Square Inch (usually shown lowercase)
PSIA	Pounds per Square Inch Absolute (usually shown lowercase)
PSIG	Pounds per Square Inch Gage (usually shown lowercase)
PSMS	Pipeline Safety Management System
PVC	Polyvinyl Chloride
RCV	Remote Control Valve
RCW	Revised Code of Washington
RDL	Readily Detectable Level
RIR	Recordable Injury Rate
RMLD	Remote Methane Leak Detector
RMV	Rupture Mitigation Valve
RNG	Renewable Natural Gas
ROW	Right-of-Way
RTL	Record Test Level
RTU	Remote Terminal Unit
SAP	Snow Action Plan
SAP	Substance Abuse Professional

Acronym	Definition of Acronym or Abbreviation
SCADA	Supervisory Control and Data Acquisition
SCBA	Self-Contained Breathing Apparatus
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SCFH	Standard Cubic Feet per Hour
SDR	Standard Dimension Ratio
SDS	Safety Data Sheet
SEPA	State Environmental Policy Act
SMAW	Shielded Metal Arc Welding
SME	Subject Matter Expert
SMYS	Specified Minimum Yield Strength
SOP	Standard Operating Procedure
SP	Steel Pipeline
SSFT	Single Service Farm Tap
STTR	Service Tee Transition Rebuild
SWPPP	Storm Water Pollution Prevention Plan
T.C.	Thermocouple
TAC	Technical Advisory Committee
TC	Temperature Compensating
TDC	Top Dead Center
TDL	Threshold Detection Level
TIMP	Transmission Integrity Management Program
TOU	Time of Use
TQM	Total Quality Management

Acronym	Definition of Acronym or Abbreviation
TX	Transformer
UAV	Unmanned Aerial Vehicle (i.e., drone)
UGS	Underground Gas Storage
UNGSF	Underground Natural Gas Storage Facility
UMC	Uniform Mechanical Code
UPS	Uninterruptible Power Supply
USDOT	U.S. Department of Transportation
UV	Ultraviolet
V.C.	Vent Connector
VAC	Volts Alternating Current
VAR	Vehicle Accident Rate
VDC	Volts Direct Current
WAC	Washington Administrative Code
WC	Water Column
WEI	Western Energy Institute
WUTC	Washington Utilities and Transportation Commission
WWP	Washington Water Power

1.4 GAS OPERATIONS AND MAINTENANCE PLANS

SCOPE:

To establish a procedure for updating Avista's Gas Standards Manual (GSM) and Gas Emergency and Service Handbook (GESH).

REGULATORY REQUIREMENTS:

§192.605, §192.613

WAC 480-93-017, 480-93-180

CORRESPONDING STANDARDS:

Spec. 4.11, Continuing Surveillance

Operations and Maintenance Plan Review

The Gas Standards Manual (GSM) and the Gas Emergency and Service Handbook (GESH) are the foundational documents in Avista's Operations and Maintenance Plan. These documents shall be reviewed and updated as applicable once each calendar year, not to exceed 15 months. Updates will be coordinated by the Pipeline Safety Engineer with assistance from the Gas Standards Manual Committee and the Gas Emergency and Services Handbook Committee.

Operations managers and the Quality Assurance Department will conduct periodic reviews of the work done by operating personnel to determine the effectiveness and adequacy of the procedures used in normal operations and maintenance. Review of construction and maintenance activities and subsequent incorporation of enhancements within the operations and maintenance plans is part of Avista's continuing surveillance program as specified in Specification 4.11, Continuing Surveillance.

Avista encourages employees (and contractors) who utilize these procedures to review them for deficiencies and recommendations. Such reviews will be analyzed, and the procedures will be modified appropriately if deficiencies are found. Reviews, analysis, and modifications will be documented by the Pipeline Safety Engineer.

GSM / GESH correction or enhancement requests should be submitted to the Pipeline Safety Engineer as they are identified. The requests will be forwarded to and reviewed / incorporated within the standards as applicable by the individual accountable for the specific standard as detailed in Table 1 of this specification.

Individuals accountable for review of the various standards will review them at the period specified and validate the following:

1) The Standard is in accordance with federal, state, and industry codes and standards.
2) Requested changes have been reviewed and incorporated within the standard as appropriate.

The required corrections / enhancements should be completed by the first of September each calendar year to include approval by the Approver as noted in Table 1. Completion by this date will allow sufficient time for the changes to be incorporated into the next year's GSM / GESH update.

Appropriate parts of the Operating and Maintenance Plan will be prepared outlining procedures necessary for conducting operations and maintenance and emergency operations before operations commence on any new pipeline system. Copies of these procedures will be kept at locations where the operations and maintenance activities are conducted.

Construction Procedures Filing With the WUTC

In the state of Washington, any new or updated construction procedures, designs, or specifications must be provided to the Commission a minimum of 45 days prior to implementation. As a general rule, this will be accomplished with the annual forwarding of the GSM / GESH to the Commission. In the event such notification needs to occur during the calendar year; it must be completed under separate correspondence.

WAC 480-93-017: State of Washington,

1. Any operator intending to construct or operate a gas pipeline facility in Washington must file with the commission all applicable construction procedures, design, and specifications used for each pipeline facility prior to operating the pipeline or have a plan and procedures manual on file with the commission. All procedures must detail the acceptable types of materials, fittings, and components for the different types of facilities in the operator's system.
2. With the exception of emergency situations, any construction plans that do not conform with Avista's existing and accepted construction procedures, designs, and specifications on file with the commission, must be submitted to the commission for review 45 days prior to the initiation of construction activity.

Records Available To Operating Personnel

This manual and all manuals comprising Avista's Gas Operating and Maintenance Plan, are to be made available to personnel performing design, construction, maintenance, and emergency response of the natural gas systems along with maintenance and construction records which includes maps.

These manuals and records are to be made available, upon request, to responsible federal and state regulatory personnel per §192.605(b)(3) and WAC 480-93-180.

Table 1 – Standards Accountability

Standard	Title	Frequency of Review	Responsible Reviewer
GSM 1.0	**Gas Standards Manual**		
1.0	Table of Contents	Annually	Pipeline Safety Engineer
1.1	Glossary	Annually	Pipeline Safety Engineer
1.2	Index	Annually	Pipeline Safety Engineer
1.3	Gas Acronyms and Abbreviations	Annually	Pipeline Safety Engineer
1.4	Gas Operations and Maintenance Plans	Annually	Pipeline Safety Engineer
2.0	**Design Standards**		
2.12	Pipe Design - Steel	Annually	Design Manager
2.13	Pipe Design - Plastic (Polyethylene)	Annually	Design Manager
2.14	Valve Design	Annually	Design Manager
2.15	Bridge Design	Annually	Design Manager
2.22	Meter Design	Annually	Design Manager
2.23	Regulator Design	Annually	Design Manager
2.24	Meter and Regulator Tables and Drawings	Annually	Design Manager
2.25	Telemetry Design	Annually	Design Manager
2.32	Cathodic Protection Design	Annually	Design Manager
2.42	Vaults - Design	Annually	Design Manager
2.52	Odorization of Natural Gas	Annually	Design Manager
3.0	**Construction**		
3.12	Pipe Installation - Steel Mains	Annually	Design Manager
3.13	Pipe Installation –Plastic (Poly) Mains	Annually	Design Manager
3.14	Precheck Layout and Inspection	Annually	Design Manager
3.15	Trenching and Backfilling	Annually	Design Manager
3.16	Services	Annually	Design Manager
3.17	Purging Pipelines	Annually	Design Manager
3.18	Pressure Testing	Annually	Design Manager
3.19	Trenchless Pipe Installation Methods	Annually	Design Manager
3.22	Joining of Pipe - Steel	Annually	Design Manager
3.23	Joining of Pipe - Plastic - Heat Fusion	Annually	Design Manager
3.24	Joining of Pipe - Plastic - Electrofusion	Annually	Design Manager
3.25	Joining of Pipe - Plastic - Mechanical	Annually	Design Manager
3.32	Repair of Steel Pipe	Annually	Design Manager
3.32A	Permanent Repair Sleeves	Annually	Design Manager
3.33	Repair of Plastic Pipe	Annually	Design Manager
3.34	Squeeze-off of PE Pipe and Prevention of Static Electricity	Annually	Design Manager
3.35	Detailed Procedure for Use of “Adams” Style Repair Clamps	Annually	Design Manager
3.42	Casing and Conduit Installation	Annually	Design Manager
3.43	Land Disturbance Requirements	Annually	Design Manager

Standard	Title	Frequency of Review	Responsible Reviewer
3.44	Exposed Pipe Evaluation	Annually	Compliance Manager
4.0	**Operations**		
4.11	Continuing Surveillance	Annually	Compliance Manager
4.12	Safety-Related Conditions	Annually	Compliance Manager
4.13	Damage Prevention Program	Annually	Damage Prevention Program Administrator
4.14	Recurring Reporting Requirements	Annually	Compliance Manager
4.15	Maximum Allowable Operating Pressure (MAOP)	Annually	Compliance Manager
4.16	Class Locations	Annually	Compliance Manager
4.17	Uprating	Annually	Design Manager
4.18	Odorization Procedures	Annually	Design Manager
4.19	Crew Activity Reporting – Washington	Annually	Compliance Manager
4.22	Customer Owned Service Lines	Annually	Compliance Manager
4.31	Operator Qualification	Annually	OQ Program Administrator
4.41	Transmission Integrity Management Program (TIMP)	Annually	TIMP Program Manager
4.42	Distribution Integrity Management Program	Annually	DIMP Program Manager
4.51	Gas Control Room Management Plan	Annually	Design Manager
4.61	Quality Assurance / Quality Control (QA/QC) Program	Annually	QA/QC Manager
4.62	Incident Assess., Failure Assess. & Lessons Learned	Annually	QA/QC Manager
5.0	**Maintenance**		
5.10	Gas Maintenance Timeframes and Matrix	Annually	Compliance Manager
5.11	Leak Survey	Annually	Leak Survey Program Manager
5.12	Regulator and Relief Inspection	Annually	Design Manager
5.13	Valve Maintenance	Annually	Design Manager
5.14	Cathodic Protection Maintenance	Annually	Design Manager
5.15	Pipeline Patrolling and Pipeline Markers	Annually	Compliance Manager
5.16	Abandonment or Inactivation of Facilities	Annually	Design Manager
5.17	Reinstating Abandoned Gas Pipeline and Facilities	Annually	Design Manager
5.18	Vault Maintenance	Annually	Design Manager
5.19	Combustible Gas Indicator Testing and Calibration	Annually	Compliance Manager
5.20	Atmospheric Corrosion Control	Annually	AC Program Manager
5.21	Maintenance of Pressure Gauges and Recorders	Annually	Design Manager
5.22	Heater Maintenance	Annually	Design Manager
5.23	Odorization Equipment Maintenance	Annually	Design Manager

Standard	Title	Frequency of Review	Responsible Reviewer
GESH	**Gas Emergency and Service Handbook**		
Section 1	Receiving and Dispatching Emergency Service Requests	Annually	Operations Support Manager
Section 2	Leak and Odor Investigation	Annually	Sr. Nat. Gas Ops Mgr.
Section 3	Carbon Monoxide (CO) Orders	Annually	Sr. Nat. Gas Ops Mgr.
Section 4	Emergency Procedures – Blowing or Uncontrolled Escaping Natural Gas	Annually	Sr. Nat. Gas Ops Mgr.
Section 5	Emergency Shutdown and Restoration of Service	Annually	Sr. Nat. Gas Ops Mgr.
Section 6	Meter, ERT, AMI and Regulator Installations	Annually	Design Manager
Section 7	Meter Turn-On Orders	Annually	Sr. Nat. Gas Ops Mgr.
Section 8	Meter Turn-Off Orders	Annually	Sr. Nat. Gas Ops Mgr.
Section 9	Meter Change Order/Meter Removal Orders	Annually	Sr. Nat. Gas Ops Mgr.
Section 10	Gas Equipment Service	Annually	Sr. Nat. Gas Ops Mgr.
Section 11	Customer Charges	Annually	Sr. Nat. Gas Ops Mgr.
Section 12	Safety Inspections	Annually	Sr. Nat. Gas Ops Mgr.
Section 13	Emergency Planning, Training and Incident Notification	Annually	Sr. Nat. Gas Ops Mgr.
Section 15	Diversion of Service	Annually	Sr. Nat. Gas Ops Mgr.
Section 16	High Bill Investigations and Customer Requested Meter Tests	Annually	Sr. Nat. Gas Ops Mgr.
Section 17	Gas Incident Field Investigation	Annually	QA/QC Manager
Tables	Gas Input to Burner in CFH	Annually	Design Manager

2.1 PIPE SYSTEMS

2.12 PIPE DESIGN - STEEL

SCOPE:

To establish a uniform procedure for designing steel gas piping systems that meets applicable regulatory codes and provide a safe and reliable operating system.

REGULATORY REQUIREMENTS:

§192.7, §192.14, §192.18, §192.53, §192.55, §192.63, §192.67, §192.101, §192.103, §192.105, §192.107, §192.109, §192.111, §192.113, §192.115, §192.141, §192.143, §192.144, §192.145, §192.147, §192.149, §192.150, §192.151, §192.153, §192.159, §192.161, §192.241, §192.461, §192.476, §192.501, §192.503, §192.505, §192.507, §192.509, §192.511, §192.611

WAC 480-93-020, 480-93-160

OTHER REFERENCES:

NACE SP0102, Section 7

CORRESPONDING STANDARDS:

Spec. 2.32, Cathodic Protection Design
Spec. 3.12, Pipe Installation – Steel
Spec. 3.15, Trenching and Backfilling
Spec. 3.18, Pressure Testing
Spec. 3.22, Joining of Pipe - Steel

DESIGN REQUIREMENTS:

General

New steel pipelines shall be in accordance with the provisions of API Standard 5L, ASTM Specification A-53, or ASTM Specification A-106. Gas Engineering shall be responsible for the design of all applications having an MAOP greater than 60 psig (high pressure designs).

Steel pipelines must be coated and cathodically protected per the requirements of Specification 2.32, Cathodic Protection Design.

Before using any new material, Gas Engineering will evaluate and approve the material by following the New Gas Material Evaluation Checklist. Following this checklist will ensure the new material meets specification and proper training has been completed with appropriate Company and contractor personnel.

Converting an Acquired System

If acquiring a system that will be converted to natural gas and is not currently subject to 49 CFR Part 192, Avista shall prepare a written plan to meet the requirements of §192.14. The plan shall include reviewing past history records of the system, or if insufficient records are available, perform appropriate tests to determine if the pipeline is in a satisfactory condition for safe operation, including visual inspection of aboveground segments and selected underground segments for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline and correct known defects in accordance with CFR 49 Part 192. The pipeline must be tested to substantiate the maximum allowable operating pressure permitted by CFR 49 Part 192 Subpart L. Records must be kept for the life of the pipeline in regard to the investigation, tests, repairs, replacements, and alterations made under the requirements of §192.14.

Steel Pipe Coating and Marking

New buried steel pipes must be applied on a properly prepared surface and coated with an approved coating which meets the requirements of §192.461 as follows:

- Have sufficient adhesion to the metal surface to effectively resist under film migration of moisture
- Be sufficiently ductile to resist cracking
- Have sufficient strength to resist damage due to handling and soil stress
- Have properties compatible with any supplemental cathodic protection
- Coating which is electrically insulating must also have low moisture absorption and high electrical resistance
- Coating must be applied and protected from damage during installation as outlined in Specification 3.12, Pipe Installation - Steel Mains.

Coated pipe shall be printed on the outside with the following information:

- Outside diameter of pipe
- Pipe wall thickness
- Pipe specification, grade, and seam type
- Coating company's name
- Date of coating application
- Coating type and thickness
- Purchase order number (Avista PO number preferred)
- Pipe manufacturer's name
- Pipe heat number

Factory-applied stenciling of the above printed information shall be maintained until the pipe has been installed in the ground. If the pipe specification information has not been maintained, the pipe shall not be used as carrier pipe. However, if the factory stencil fails, Avista personnel may reapply the required information on the pipe before installation with complete verification of all data of the original stencil.

Design Formula for Steel Pipe

The design formula for steel pipe is given as follows:

$$P = \frac{2St}{D} \times F \times E \times T$$

Where:

P = design pressure (psig)
S = specified minimum yield strength (psi) in accordance with §192.107
D = outside diameter (in)
t = nominal wall thickness (in) in accordance with §192.109
F = design factor determined in accordance with §192.111
E = longitudinal joint factor determined in accordance with §192.113
T = temperature derating factor determined in accordance with §192.115

The design of new gas facilities and any subsequent additions or alterations to existing facilities shall meet the maximum allowable operating pressure (MAOP) requirements of the pipeline. Future plans for expansion or uprating may dictate a higher design MAOP. When possible, pipelines should be designed so the MAOP of the pipeline is below 20 percent of the specified minimum yield strength (SMYS) of the pipe.

Allowance shall be made in the overall design, in addition to internal pipeline hoop stress, for other possible stress factors such as overburden, fill, external loads, thermal expansion and contraction, or pipeline bending.

Class Location Considerations

For pipelines that must be designed to operate at or in excess of 20 percent SMYS, design considerations and pressure testing considerations must be made, as the pipeline will ultimately be limited to an MAOP as specified by its Population Class Location. Refer to Specification 4.16, Class Locations.

The MAOP of a pipeline may not exceed that which will cause the following hoop stress as a percentage of SMYS for the indicated Population Class Location*:

Class 1 - 72 percent SMYS
Class 2 - 60 percent SMYS
Class 3 - 50 percent SMYS
Class 4 - 40 percent SMYS

*Note: A pipeline may be operated at a pressure which equates to “one class level out” if the pipeline has previously been tested to 90 percent SMYS for the required test duration (Reference notes in subsection “Pressure Testing” in this specification).

Transmission Lines – Design of Pipe and Components

- Each transmission line and each replacement of line pipe, valve, fitting, or other line component in a transmission line (regardless of operating hoop stress) constructed after July 1, 2020, has the following design and recordkeeping criteria:

    - Collect or make and retain, for the life of the pipeline, records documenting that the pipe is designed to withstand anticipated external pressures and loads in accordance with §192.103 and document that the determination of design pressure for the pipe is made in accordance with §192.105.
    - Records that document the physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe in accordance with §192.53 and §192.55 shall be made and retained for the life of the pipeline. Records must include tests, inspections, and attributes required by the manufacturing specifications applicable at the time the pipe was manufactured or installed.
    - Records documenting the manufacturing standard and pressure rating to which each valve was manufactured and tested shall be made and retained for the life of the pipeline. Flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches must have records documenting the manufacturing specification in effect at the time of manufacture, including yield strength, ultimate tensile strength, and chemical composition of materials.
    - Must be designed and constructed to accommodate the passage of instrumented internal inspection devices in accordance with NACE SP0102, Section 7. This does not apply to the following:

        - Manifolds
        - Station piping such as at compressor stations, meter stations, or regulator stations
        - Crossovers
        - Sizes of pipe for which an instrumented internal device is not commercially available
        - Transmission lines, operated in conjunction with a distribution system which are installed in Class 4 locations

- For steel transmission pipeline segments constructed on or before July 1, 2020, the following documentation shall be retained for the life of the pipeline if they are available:
    - Pipe design and the determination of design pressure in accordance with §192.103 and §192.105.
    - Physical characteristics of the pipeline, including diameter, yield strength, ultimate tensile strength, wall thickness, seam type, and chemical composition of materials for pipe.
    - Manufacturing standard and pressure rating for valves, flanges, fittings, branch connections, extruded outlets, anchor forgings, and other components with material yield strength grades of 42,000 psi (X42) or greater and with nominal diameters of greater than 2 inches.

Transmission Line- Internal Corrosion Control

Each new transmission line and each replacement of line pipe, valve, fitting, or other line component in an onshore transmission line that was installed after May 23, 2007, must have features incorporated into its design and construction to reduce the risk of internal corrosion per the requirements of §192.476. At a minimum, unless it is impracticable or unnecessary to do so, it must:

- Be configured to reduce the risk that liquids will collect in the line
- Have effective liquid removal features whenever the configuration would allow liquids to collect
- Allow use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion

There are design features that can be incorporated to address the requirements above including:

1. Minimizing dead ends and low areas
2. Minimizing aerial crossings, since these can result in variation of temperature
3. Designing for turbulent flow, in which the velocity at a given point varies erratically in magnitude and direction, to decrease the chance of liquids separating from the flow and accumulating
4. Designing a pipeline to minimize entry of water and corrosive gases at receipt locations
5. Providing slam valves to isolate systems when corrosive gas is expected
6. Applying coatings to interior walls to inhibit internal corrosion
7. Identifying critical low spots and instrument the pipeline to monitor relevant operating conditions (temperature, pressure, velocity, dew point)
8. Evaluating seasonal nature of delivery and capacity patterns and design to avoid no flow or low flow conditions
9. Including equipment to evaluate gas characteristics and
10. Including equipment to allow sampling at key areas, such as pig traps, isolated sections with no flow, dead ends, and river and road crossings

When there are changes to the configuration of a transmission line, an evaluation must be done on the impact of the change in regard to internal corrosion risk to the downstream portion of an existing onshore transmission line and provide for removal of liquids and monitoring of internal corrosion as appropriate.

Records must be maintained to demonstrate compliance with this requirement. If it is impractical or unnecessary to incorporate design features from 1 - 3 listed above, it shall be documented through construction records and as-built drawings.

Transmission Line- Approval of Change

When considering a modification to Avista's transmission assets, an Approval of Change to Transmission Pipeline System form is required to be filled out during the design or planning process. This form shall be forwarded to the appropriate manager for approval of the change prior to the design or change. See Section 13.4, Transmission Integrity Management Program (TIMP), for a list of changes with the associated approving manager.

Part A of the Approval of Change to Transmission Pipeline System form is filled out by the individual initiating the proposed change to the system and includes a list of reasons for making the proposed change. The initiator chooses the appropriate reason driving the change to the transmission pipeline system and provides a description of the proposed change(s).

The initiator then signs and dates the form and forwards the form to the appropriate manager for approval. Part B – Preliminary Review is then filled out by the manager. If approved, the form then goes to the Pipeline Integrity Program Manager for processing if there are any conditions of approval identified as outlined in Avista's Transmission IMP Plan, Section 13 - Management of Change Plan. The Pipeline Integrity Program Manager will file the document as appropriate.

Reporting of Proposed Construction of Transmission Main (WA)

WAC 480-93-160: In the state of Washington, a report must be filed with the WUTC at least 45 days prior to the construction or replacement of any segment of a gas transmission pipeline equal to or greater than 100 feet in length. Emergency repairs are exempt from this rule.

Design of Pipeline Components

Company approved pipeline components shall meet the requirements of Part 192, Subpart D. Pressure ratings for Company approved fittings, valves, and other piping components shall be equal to or greater than the MAOP for the pipeline being built. Design of pipeline components shall be based on unit stresses equivalent to those allowed for comparable material in pipe or based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component. In addition, fittings, valves, and other piping components to be tested as part of the pipeline system must be able to withstand the test pressure, which is generally a minimum of 1.5 times the proposed MAOP. Each fitting used to make a hot tap must be designed for at least the MAOP of the pipeline system. Welded branch connections made to pipe in the form of a single connection, header, or manifold as a series of connections must be designed to ensure that the strength of the pipeline system is not reduced by considering the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and external loadings due to thermal movement, weight, and vibration. Branch sizes larger than 2 inches in diameter must be evaluated per ASME B31.8, Section 831.42.

Extruded outlets must be suitable for anticipated service conditions and must be at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.

Steel butt weld fittings must have pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting must at least equal the computed bursting strength of pipe of the designed material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.

Field fabricated fittings (e.g., orange-peel caps and reducers) may not be used without prior approval from Gas Engineering. Field fabricated fittings are not approved for use on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe. This does not include mitering of weld elbow fittings as discussed in Specification 3.12, Pipe Installation – Steel Mains.

Flat closures (circular plate) may only be used on systems with an MAOP of 60 psig or less and on pipe that is 2 inches nominal diameter and smaller. Fish tails (pinch and weld) shall not be used.
Threaded fittings shall not be used on aboveground pipeline facilities 3 inch and larger without concurrence by Gas Engineering. The minimum metal thickness for threaded fittings may not be less than specified for the pressure and temperatures in the applicable standards as referenced in Part 192.

When close all-threaded nipples are used, the remaining wall thickness must meet the minimum wall thickness requirements.

Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.

Pipeline systems should be welded where possible. Welding provides a stronger joint with less likelihood of future leakage.

Full encirclement type line stopper fittings should be used on steel pipelines with an MAOP greater than 60 psig. Full encirclement fittings provide added stability for the tapping assembly. Generally, service valve installations do not require full encirclement fittings. Partial encirclement or top-stopper type fittings may be used on pipelines with an MAOP greater than 60 psig provided the pipe and tapping gear are properly supported to minimize the stresses induced during tapping and stopping.

Pressure Vessels and Prefabricated Units

Prefabricated welded assemblies should be composed of standard pipe and fittings using circumferential welds whenever possible. Prefabricated welded assemblies that are composed of standard pipe and fittings using circumferential welds (such as regulator stations and meter set assemblies) are not considered a prefabricated unit. Fabrications using plate and longitudinal seam welds (such as odorizers, heaters and some filter housings) are considered a prefabricated unit and shall be designed, constructed, and tested according to ASME Boiler Pressure Vessel Code and should come with a U-1 stamp and documentation whenever possible. The following requirements shall be met for permanently or temporarily installed prefabricated units or pressure vessels:

- Preferred Method - Pressure test the prefabricated unit or pressure vessel in its final installation location per the requirements of Specification 3.18, Pressure Testing. The test may be performed before or after it has been tied-in to the pipeline. Test records shall be kept for the life of the asset; or
- Pressure test prior to installation (shop or manufacturer test) and then perform an inspection once it is installed prior to being placed into operation. The prefabricated unit or pressure vessel shall be inspected after it has been placed on its support structure at its final installation location to confirm that the prefabricated unit or pressure vessel was not damaged during any prior operation, transportation, or installation into the pipeline. The inspection may take place before or after it has been tied-in to the pipeline. Any inspection, repair or test records must be kept for the life of the asset. The inspection procedure and documented inspection shall include at a minimum:
    - Visual inspection for vessel damage, including inlets, outlets, and lifting locations.
    - Injurious defects that are an integrity threat may include dents, gouges, bending, corrosion, and cracking. If any defects are found, the prefabricated unit or pressure vessel must be either non-destructively tested, re-pressure tested, or remediated in accordance with the applicable part 192 requirements for a fabricated unit or with the applicable ASME Boiler Pressure Vessel Code requirements.

For temporary use of a prefabricated unit or pressure vessel, such as a temporary odorizer, the vessel may be temporarily installed in a pipeline facility in order to complete a testing, integrity assessment, repair, odorization, or emergency response related task, including noise or pollution abatement. The temporary prefabricated unit or pressure vessel must be promptly removed after the task is complete.

If operational or environmental constraints require leaving a temporary prefabricated unit or pressure vessel in place for longer than 30 days, PHMSA and the State pipeline safety authority must be notified in accordance with §192.18.

An existing prefabricated unit or pressure vessel that is temporarily removed from a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response related task, including noise or pollution abatement, must be visually inspected for damage and injurious defects as required above. However, a new pressure test is not required provided no damage or threats to the operational integrity were identified during the inspection and the MAOP of the pipeline is not increased.

An existing prefabricated unit or pressure vessel that is relocated and operated at a different location must be designed and constructed in accordance with this section and meet the testing requirements for a newly installed prefabricated unit or pressure vessel.

Joining of Steel Pipeline Components

Mechanical fittings shall not be used to join steel pipe with the exception of bolted valves, flanges, expansion joints, pressure couplings, threaded connections, and Victaulic couplings. In each case, the assembly must be properly rated to meet or exceed the pipeline system MAOP.

Threaded connections shall not be used on underground pipeline systems. Flanged connections should also be avoided on underground pipeline systems.

Flanged Connections

Flanges and flange accessories must be designed to meet the minimum requirements of ASME B16.5, MSS SP-44, or equivalent. Each flange assembly must be rated to operate at the MAOP of the system and must maintain its physical and chemical properties at all temperatures the system may operate in.

ASTM A105 STEEL PIPE FLANGES AND FLANGED FITTINGS (ASME B16.5)

	Rating in PSIG		
Temperature (°F)	**ANSI 150**	**ANSI 300**	**ANSI 600**
−20 to 100	285	740	1480
101 to 200	260	675	1360
201 to 300	230	655	1310

Steel flange ratings are often referred to in any of the following ways, all of which have the same meaning:

Class 150	ANSI 150
ASA 150	150 pound
150 #	150 LB

For flange joints, the bolting (bolts or stud bolts) used shall extend completely through the nuts and be in conformance with ANSI B31.8 Section 831.22 and ASME B16.5 Section 5.3.

Between the temperatures of -20 degrees F and 400 degrees F, ANSI 150 and ANSI 300 flange joints should use ASTM A307 Gr. B bolting; this is classified as “Low Strength”. Outside this temperature range and for ratings higher than ANSI 300, bolting shall conform to ASTM A193 Grade B7, or as defined by ASME B16.5 as “High Strength”.

When using ASTM A307 bolting, either ASTM A563 or ASTM A194 nuts may be used. When using ASTM A193 bolting, only ASTM A194 nuts may be used. Studs shall be used on ANSI 600 flange joints and greater. See table below for a summary:

FLANGE and FASTENER COMBINATIONS MINIMUM REQUIREMENTS

Flange Type, ANSI	Bolts / Studs	Nuts	Gaskets
150 FF	ASTM A307 Grade B – Bolts or Studs ∗	ASTM A563 Grade A, Heavy Hex	Type E
150 RF	ASTM A307 Grade B – Bolts or Studs ∗	ASTM A563 Grade A, Heavy Hex	Type F
300 RF	ASTM A307 Grade B – Bolts or Studs ∗	ASTM A563 Grade A, Heavy Hex	Type F
600 RF	ASTM A193 Grade B7 – Studs Only	ASTM A194 Grade 2H, Heavy Hex	Type F

*When the operating temperature will be outside −20□F to 450□F, use ASTM A193 Grade B7 bolts and ASTM A194 Grade 2H nuts (see ASME B31.8, paragraph 831.22[b]).

SAE Grade 8 bolt and nuts may be found in the field and are acceptable but should not be installed on new ANSI 150 and 300 applications.

ASTM A193, A194, and A307 hardware is stamped with its grade, ASTM 563 Grade A nuts are not marked.

Type E gaskets are a full-faced gasket with the same outside diameter as the flange. Precision cut holes match the bolt size and pattern for the intended flange. This design facilitates proper alignment of the gasket during installation and keeps foreign material from shorting the flange insulation. Type E gaskets are only to be used when bolting flat faced flanges.

Type F gaskets are made to fit the raised face portion of the flange only. As there are no bolts holes in the Type F gasket, the inside diameter of the bolt hole circle is slightly smaller than the outside diameter of the gasket, assuring an exact, automatic positioning of the gasket.

Supports - General

Each pipeline and its associated equipment must be anchored or supported to prevent undue strain on connected equipment, resist longitudinal forces caused by a bend or offset in the pipe, and prevent or damp out excessive vibrations.

Each mechanical pipeline support or anchor must be made of durable, noncombustible material, and must be designed with enough flexibility to allow free expansion and contraction between supports. Supports or anchors shall not be welded to the carrier pipe. Supports or anchors should be mechanically attached to carrier pipe and cathodic isolation should be provided where needed. Supports should also have the ability to be lowered away from the gas carrying pipe to allow for atmospheric corrosion inspection.

For exposed transmission pipelines operating at a stress level 50 percent or more of SMYS, a support must be provided by a member that completely encircles the pipe.

Thermal Contraction and Expansion

Steel pipe expands or contracts at a rate of 0.000078 inch for every foot of pipe subjected to a 1-degree F temperature change. Therefore, the following equation may be used to calculate thermal expansion or contraction in steel pipe:

$\delta = 0.000078\ (L)(\ \Delta t)$

Where: δ = elongation if (+) or contraction if (-) (in)
L = length of steel pipe (ft)
Δt = change in temperature (°F), (+) if increase or (-) if decrease

Longitudinal Stress

The following equations may be used to calculate longitudinal stress induced by thermal change for restrained pipe:

$\sigma_+ = \propto E(\Delta t)$
$\sigma_+ = 195\ (\Delta t)$

Where: σ_+ = longitudinal stress (psi)
$\propto$ = coefficient of thermal expansion = $6.5\text{x}10^{-6}$ (in/in-°F)
Δt = change in temperature (°F), (+) if increase or (-) if decrease
E = modulus of elasticity = $30\text{x}10^{6}$ psi

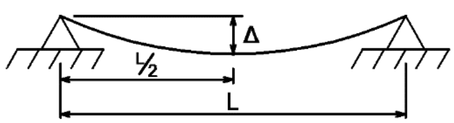
Deflection and Bending Stress

Supports must be spaced so as not to cause excessive deflection and excessive stress in the pipeline being supported. The following equations may be of assistance in calculating deflection and bending stresses:

DEFLECTION

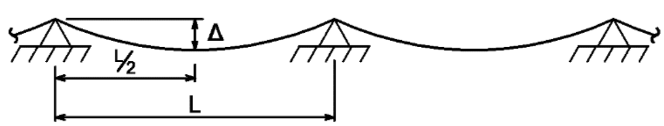
Max deflection of empty pipe caused by its weight between supports based on a single span with free ends:

$$\Delta = \frac{22.5\ WL\text{^}4}{EI}$$



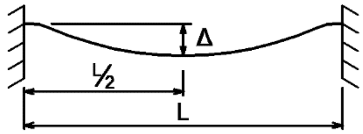
Max deflection of empty pipe caused by its weight between supports based on a continuous span:

$$\Delta = \frac{22.5\ WL\text{^}4}{EI}$$



Max deflection of empty pipe caused by its weight between supports based on a single span with fixed ends:

$$\Delta = \frac{22.5\ WL^4}{EI}$$



Where: Δ = deflection (in)
W = weight of pipe (lbs/ft). See the Steel Pipe Data Table in this specification
L = distance between supports (ft)
E = modules of elasticity (psi)
I = moment of inertia (in^4). See the Steel Pipe Data Table in this specification

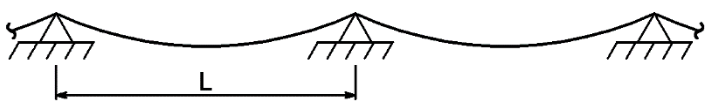
BENDING STRESS

Max bending stress in empty pipe caused by its weight between supports based on a single span with free ends:

$$\sigma_B = \frac{1.5\ WL^2}{Z}$$

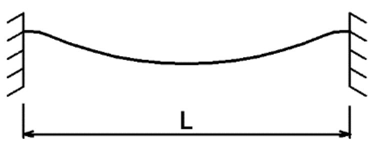
Max bending stress in empty pipe caused by its weight between supports based on a continuous span:

$$\sigma_B = \frac{1.2\ WL^2}{Z}$$



Max bending stress in empty pipe caused by its weight between supports based on single span with fixed ends:

$$\sigma_B = \frac{WL^2}{Z}$$



Where: σ_B = bending stress (psi)
W = weight of pipe (lbs/ft). See the Steel Pipe Data Table in this specification
L = distance between supports (ft)
Z = section modulus (in^3). See the Steel Pipe Data Table in this specification

Seismic Supports

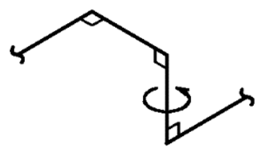
In seismic prone areas, pipe supports, and hangers should be designed to withstand seismic forces. In addition to static loads of pipeline systems, use an additional 0.2g for vertical seismic force and 0.3g for horizontal seismic force (i.e., supports and hangers must be able to withstand 120 percent of load weight of pipeline system in the vertical direction and 30 percent of load weight in the horizontal direction).

Torsional Stress

Design considerations must be observed if the pipe will be subjected to torsional stresses. This most often will occur when a pipe is supported on a structure such as a bridge crossing in a “double offset” configuration. Stresses may be induced through temperature change or by other load factors.

Maximum torsional stress of an empty pipe with restrained ends (for the section being twisted) is:

$$\tau max = \frac{Tro}{J}$$



Where: τmax = maximum torque (psi)
T = torque (in-lb)
ro = outside radius = do/2 (in)
J = Polar moment of inertia = $\pi/32$ (do4 – di4)

Where: do = outside diameter (in)
di = inside diameter (in)

Washington State Proximity Considerations

WAC 480-93-020: The following proximity considerations are required in the state of Washington.

Gas facilities having a MAOP greater than 500 PSIG shall not be operated within 500 feet of the places described below:

- A building that is in existence or under construction prior to the date authorization for construction is filed with the WUTC and that is not owned and used by the petitioning operator in its gas operations; or
- A high occupancy structure or area such as a playground, recreation area, outdoor theater, or other place of public assembly, which is occupied by 20 or more persons, on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive), which is in existence or under construction prior to the date authorization for pipeline construction is filed with the commission; and
- A public highway, as defined in RCW 81.80.010(3).

Gas Facilities having a MAOP greater than 250 PSIG and including 500 PSIG shall not be operated within 100 feet of the places described below:

- A building that is in existence or under construction prior to the date authorization for construction is filed with the WUTC and that is not owned and used by the petitioning operator in its gas operations; or
- A high occupancy structure or area such as a playground, recreation area, outdoor theater, or other place of public assembly, which is occupied by 20 or more persons, on at least 5 days a week for 10 weeks in any 12-month period (the days and weeks need not be consecutive), which is in existence or under construction prior to the date authorization for pipeline construction is filed with the commission.

For proposed new construction of pipelines having the characteristics listed above, Avista must provide documentation proving that it is not practical to select an alternate route that will avoid such locations and further provide documents that demonstrate that the operator has considered the possibility of the future development of the area and has designed the pipeline facilities accordingly.

During the review process, Avista must provide maps and records to the Commission showing the exact location of the pipeline and the shortest direct distance to the places described above. Upon request of the Commission, Avista must provide maintenance, construction, and operational history of the pipeline system. Also, Avista must provide an aerial photograph showing the exact location of the pipeline in reference to the places listed above.

Protection of Aboveground Steel Pipelines

Each aboveground transmission line or main not located in inland navigable water areas must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing some type of barricade.

Clearances & Cover

See Specification 3.15, Trenching and Backfilling for the requirements of cover and clearances for steel pipelines.

Easement Considerations

When designing pipe to be installed in an easement, the minimum preferred easement width is 20 feet extending 10 feet in each direction from the centerline of the pipe. The easement language should ensure the Company’s ability to maintain access to the pipe and restrict installation of structures, bushes, trees, and other vegetation that could be detrimental to the buried facility within the easement.

Steel Pipe Data Tables

The following tables provide useful dimensional and engineering data for various steel pipe specifications:

STEEL PIPE DATA TABLE

NOM. PIPE SIZE	WALL THICKNESS		DIMENSIONS			WEIGHTS		CIRCUMFERENCE		AREAS		DESIGN PROPERTIES			VOLUME	
	IRON PIPE SIZE	SCH. NO.	OUTSIDE DIA.	INSIDE DIA.	WALL THICK-NESS	EMPTY PIPE	PLUS WATER IN PIPE	EXTERNAL	INTERNAL	CROSS-SECTIONAL FLOW	METAL	MOMENT OF INERTIA (I)	SECTION MODULUS	RADIUS OF GYRATION	INSIDE PIPE	
IN.			IN	IN.	IN.	LB. PER FT.	LB. PER FT.	IN.	IN.	$IN.^2$	$IN.^2$	$IN.^4$	$IN.^3$	IN.	3 FT. PERFT.	GAL. PERFT.
3/4	STD.	40	1.050	.824	.113	1.131	.231	3.299	2.589	.5333	.3326	.0370	.0705	.3337	.0037	.0277
	XS	80	1.050	.742	.154	1.474	.187	3.299	2.331	.4324	.4335	.0448	.0853	.3214	.0030	.0225
1	STD.	40	1.315	1.049	.133	1.679	.375	4.131	3.296	.8643	.4939	.0873	.1328	.4205	.0060	.0449
	XS	80	1.315	.957	.179	2.172	.312	4.131	3.007	.7193	.6388	.1056	.1606	.4066	.0050	.0374
1 1/4	STD.	40	1.660	1.380	.140	2.273	.648	5.215	4.335	1.4957	.6685	.1947	.2346	.5397	.0104	.0777
	XS	80	1.660	1.278	.191	2.997	.556	5.215	4.015	1.2828	.8815	.2418	.2913	.5237	.0089	.0666
1 1/2	STD.	40	1.900	1.610	.145	2.718	.882	5.969	5.058	2.0358	.7995	.3099	.3262	.6226	.0141	.1058
	XS	80	1.900	1.500	.200	3.631	.766	5.969	4.712	1.7671	1.0681	.3912	.4118	.6052	.0123	.0918
2	STD.	40	2.375	2.067	.154	3.65	1.45	7.461	6.494	3.356	1.075	.666	.561	.787	.0223	.1743
	XS	80	2.375	1.939	.218	5.02	1.28	7.461	6.092	2.953	1.477	.868	.731	.766	.0205	.1534
3			3.500	3.218	.141	5.06	3.52	10.996	10.104	8.129	1.492	2.102	1.201	1.187	.0564	.4222
			3.500	3.188	.156	5.57	3.46	10.996	10.015	7.982	1.639	2.296	1.312	1.184	.0554	.4140
			3.500	3.124	.188	6.65	3.32	10.996	9.814	7.665	1.956	2.691	1.538	1.173	.0532	.3982
	STD.	40	3.500	3.068	.216	7.58	3.20	10.996	9.638	7.393	2.228	3.017	1.724	1.164	.0513	.3840
	XS	80	3.500	2.900	.300	10.25	2.86	10.996	9.111	6.605	3.016	3.894	2.225	1.136	.0459	.3431
4		-	4.500	4.188	.156	7.24	5.97	14.137	13.157	13.775	2.129	5.028	2.235	1.537	.0957	.7155
		-	4.500	4.124	.188	8.66	5.79	14.137	12.956	13.358	2.547	5.930	2.636	1.526	.0928	.6939
	STD.	40	4.500	4.026	.237	10.79	5.52	14.137	12.648	12.730	3.174	7.233	3.214	1.510	.0884	.6613
	XS	80	4.500	3.826	.337	14.98	4.98	14.137	12.020	11.497	4.407	9.610	4.271	1.477	.0798	.5972
6		-	6.625	6.313	.156	10.78	13.6	20.813	19.829	31.30	3.17	16.59	5.01	2.29	.2174	1.6260
		-	6.625	6.281	.172	11.85	13.4	20.813	19.732	30.96	3.49	18.16	5.48	2.28	.2152	1.6096
			6.625	6.249	.188	12.92	13.3	20.813	19.632	30.67	3.80	19.71	5.95	2.28	.2130	1.5932
	STD.	40	6.625	6.065	.280	18.97	13.5	20.813	19.054	28.89	5.58	28.14	8.50	2.25	.2006	1.5008
	XS	80	6.625	5.761	.432	28.57	13.3	20.813	18.099	26.07	8.40	40.49	12.22	2.19	.1810	1.3541
8			8.625	8.281	.172	15.53	23.3	27.096	26.018	53.86	4.57	40.81	9.46	2.99	.3740	2.7979
			8.625	8.248	.188	16.94	23.2	27.096	25.915	53.44	4.98	44.37	10.29	2.98	.3711	2.7763
			8.625	8.219	.203	18.30	23.0	27.096	25.821	53.06	5.38	47.64	11.05	2.98	.3685	2.7562
			8.625	8.187	.219	19.66	22.8	27.096	25.720	52.64	5.78	51.12	11.85	2.97	.3656	2.7347
			8.625	8.063	.281	25.07	22.1	27.096	25.331	51.05	7.37	64.18	14.86	2.95	.3546	2.6524
	STD.	40	8.625	7.951	.322	28.55	21.7	27.096	25.073	50.03	8.40	72.49	16.21	2.94	.3474	2.5988
	XS	80	8.625	7.625	.500	43.39	19.8	27.096	23.955	45.66	12.76	105.72	24.51	2.88	.3171	2.3721
10	-		10.750	10.374	.188	31.21	36.6	33.772	32.597	84.52	6.24	87.01	16.19	3.73	.5870	4.3909
			10.750	10.344	.203	23.87	36.4	33.772	32.497	84.04	6.73	93.57	17.41	3.73	.5836	4.3654
	-		10.750	10.312	.219	24.63	36.2	33.772	32.396	83.52	7.25	100.48	18.69	3.72	.5800	4.3396
		20	10.750	10.250	.250	28.04	35.8	33.772	32.201	82.52	8.25	113.71	21.16	3.71	.5730	4.2885
	STD.	40	10.750	10.020	.365	40.48	34.2	33.772	31.479	78.85	11.91	160.73	29.90	3.67	.5476	4.0963
	XS	60	10.750	9.750	.500	54.74	32.4	33.772	30.631	74.66	16.10	211.95	39.43	3.63	.5185	3.8785
12			12.750	12.344	.203	27.2	52.0	40.055	38.780	119.9	7.99	157.2	24.7	4.43	.8326	6.2281
			12.750	12.312	.219	29.3	51.6	40.055	38.679	119.1	8.62	169.3	26.5	4.43	.8268	6.1847
		20	12.750	12.250	.250	33.4	51.1	40.055	38.485	117.2	9.82	191.8	30.1	4.42	.8185	6.1225
			12.750	12.188	.281	37.4	50.6	40.055	38.290	116.7	11.01	214.0	33.6	4.41	.8104	6.0619
			12.750	12.126	.312	47.4	50.0	40.055	38.095	115.5	12.19	235.9	37.0	4.40	.8020	5.9992
	STD.		12.750	12.000	.375	49.6	49.0	40.055	37.699	113.1	14.58	278.3	43.8	4.38	.7854	5.9752
	XS		12.750	11.750	.500	65.4	47.0	40.055	36.914	108.4	19.24	361.5	56.7	4.33	.7530	5.6329
16			16.00	15.562	.219	36.9	82.4	50.265	48.889	190.2	10.86	338.0	42.3	5.58	1.3208	9.8796
		10	16.00	15.500	.250	42.0	81.8	50.265	48.695	188.7	12.37	384.0	48.0	5.57	1.3104	9.8008
			16.00	15.435	.281	47.0	81.1	50.265	48.500	187.2	13.88	429.0	53.6	5.56	1.2999	9.7239
		20	16.00	15.376	.312	52.0	80.5	50.265	48.305	185.7	15.38	473.0	59.2	5.55	1.2895	9.6460
	STD.	30	16.00	15.250	.375	63.0	79.2	50.265	47.909	182.7	18.41	562.0	70.3	5.53	1.2684	9.4885
	XS	40	16.00	15.000	.500	83.0	76.6	50.265	47.124	176.7	24.35	732.0	91.5	5.48	1.2272	9.1800
18		10	18.000	17.500	.250	47.0	104.2	56.549	54.978	240.5	13.94	549.0	61.0	6.28	1.6703	12.4950
			18.000	17.438	.281	53.0	103.5	56.549	54.783	238.8	15.64	614.0	68.2	6.27	1.6585	12.4065
			18.000	17.375	.312	59.0	102.5	56.549	54.585	237.1	17.36	679.0	75.5	6.25	1.6465	12.3160
	STD.		18.000	17.250	.375	71.0	101.3	56.549	54.192	233.7	20.78	807.0	89.6	6.23	1.6230	12.1405
	XS		18.000	17.000	.500	93.0	98.4	56.549	53.407	227.0	27.49	1053.0	117.0	6.19	1.5763	11.7912

NOM. PIPE SIZE	WALL THICKNESS		DIMENSIONS			WEIGHTS		CIRCUMFERENCE		AREAS		DESIGN PROPERTIES			VOLUME	
	IRON PIPE SIZE	SCH. NO.	OUTSIDE DIA.	INSIDE DIA.	WALL THICK-NESS	EMPTY PIPE	PLUS WATER IN PIPE	EXTERNAL	INTERNAL	CROSS-SECTIONAL FLOW	CROSS-SECTIONAL METAL	MOMENT OF INERTIA (I)	SECTION MODULUS	RADIUS OF GYRATION	INSIDE PIPE	
IN.			IN	IN.	IN.	LB. PER FT.	LB. PER FT.	IN.	IN.	$IN.^2$	$IN.^2$	$IN.^4$	$IN.^3$	IN.	3 FT. PER FT.	GAL. PER FT.
		10	20.000	19.500	.250	53.0	129.4	62.832	61.261	298.8	15.51	756.0	75.6	6.98	2.0739	15.5142
			20.000	19.438	.281	59.0	128.6	62.832	61.066	296.8	17.41	846.0	84.6	6.97	2.0608	15.4157
			20.000	19.376	.312	66.0	127.8	62.832	60.872	294.9	19.30	935.0	93.5	6.96	2.0476	15.3175
20			20.000	19.312	.344	78.0	126.9	62.832	60.670	292.9	21.24	1026.0	102.6	6.95	2.0341	15.2154
	STD.	20	20.000	19.250	.375	79.0	126.1	62.832	60.476	291.0	23.12	1113.0	111.3	6.94	2.0211	15.1189
			20.000	19.188	.406	85.0	125.3	62.832	60.281	289.2	24.99	1200.0	120.0	6.93	2.0081	15.0206
	XS	30	20.000	19.000	.500	104.0	122.9	62.832	59.690	283.5	30.63	1457.0	145.7	6.90	1.9689	14.7288
		10	22.000	21.500	.250	58.0	157.4	69.115	67.544	363.1	17.18	1010.0	91.8	7.69	2.5215	18.8610
			22.000	21.438	.281	65.0	156.4	69.115	67.349	361.0	19.17	1131.0	102.8	7.68	2.5067	18.7511
22			22.000	21.376	.312	72.0	155.5	69.115	67.155	358.9	21.26	1250.0	113.7	7.67	2.4922	18.6428
	STD.	20	22.000	21.250	.375	87.0	153.7	69.115	66.759	354.7	25.48	1490.0	135.4	7.65	2.4629	18.4237
	XS	30	22.000	21.000	.500	115.0	150.1	69.115	65.973	346.4	33.77	1952.0	177.5	7.60	2.4053	17.9926
			24.000	23.500	.250	63.0	188.0	75.398	73.827	433.7	18.65	1315.0	109.6	8.40	3.0121	22.5317
		10	24.000	23.438	.281	71.0	187.0	75;398	73.633	431.5	20.94	1472.0	122.7	8.39	2.9962	22.4130
			24.000	23.376	.312	79.0	186.0	75.398	73.438	429.2	23.22	1629.0	135.7	8.38	2.9804	22.2946
24			24.000	23.312	.344	87.0	185.0	75.398	72.237	426.8	25.56	1789.0	149.1	8.36	2.9641	22.1711
	STD.		24.000	23.250	.375	95.0	184.0	75.398	73.042	424.6	27.83	1942.0	161.9	8.35	2.9483	22.0549
		20	24.000	23.188	.406	102.0	183.0	75.398	72.847	422.3	30.09	2095.0	174.6	8.34	2.9326	21.9359
			24.000	23.125	.438	110.0	181.8	75.398	72.649	420.0	32.39	2248.0	187.4	8.33	2.9167	21.8167
	XS		24.000	23.000	.500	125.0	180.0	75.398	72.257	415.5	36.91	2549.0	212.4	8.31	2.8852	21.5831
			26.000	25.500	.250	69.0	221.3	81.681	80.111	510.7	19.85	1676.0	128.9	9.10	3.5465	26.5278
		10	26.000	25.376	.312	86.0	219.2	81.681	79.721	505.8	25.18	2077.0	159.8	9.08	3.5122	26.2727
26			26.000	25.312	.344	94.0	218.1	81.681	79.520	503.2	27.73	2282.0	175.5	9.07	3.4945	26.1386
	STD.		26.000	25.250	.375	103.0	217.0	81.681	79.325	500.7	30.19	2478.0	190.6	9.06	3.4774	26.0125
			26.000	25.188	.406	111.0	215.9	81.681	79.130	498.3	32.64	2673.0	205.7	9.04	3.4603	25.8830
	XS	20	26.000	25.000	.500	136.0	212.7	81.681	78.540	490.9	40.06	3257.0	250.5	9.02	3.4088	25.4999
			30.000	29.438	.281	89.0	294.9	94.248	92.435	680.6	26.23	2896.0	193.1	10.51	4.7264	35.3533
		10	30.000	29.376	.312	99.0	293.7	94.248	92.287	677.8	29.10	3206.0	213.8	10.50	4.7067	35.2082
			30.000	29.312	.344	109.0	292.4	94.248	92.086	674.8	32.05	3524.0	234.9	10.49	4.6862	35.0526
30	STD.		30.000	29.250	.375	119.0	291.0	94.248	91.892	672.0	34.90	3829.0	255.3	10.47	4.6664	34.9069
			30.000	29.188	.406	128.0	289.0	94.248	91.696	669.1	37.75	4133.0	275.5	10.46	4.6466	34.7566
			30.000	29.125	.438	138.0	288.7	94.248	91.499	666.2	40.63	4440.0	296.0	10.45	4.6264	34.6054
	XS	20	30.000	29.000	.500	158.0	286.2	94.248	91.106	660.5	46.34	5042.0	336.1	10.43	4.5869	34.3167
		10	34.000	33.376	.312	112.0	379.1	106.814	104.854	874.9	33.02	4685.0	275.6	11.91	6.0757	45.4494
			34.000	33.312	.344	124.0	377.7	106.814	104.653	871.5	35.37	5153.0	303.0	11.90	6.0524	45.2752
34	STD.		34.000	33.250	.375	135.0	376.3	106.814	104.458	868.3	39.61	5599.0	329.4	11.89	6.0299	45.1068
			34.000	33.188	.406	146.0	374.9	106.814	104.283	865.1	42.84	6045.0	355.6	11.88	6.0074	44.9357
			34.000	33.124	.438	157.0	373.4	106.814	104.062	861.7	46.18	6504.0	382.6	11.87	5.9843	44.7656
	XS	20	34.000	33.000	.500	179.0	370.6	106.814	103.673	855.3	52.62	7384.0	434.3	11.85	5.9396	44.4311
		10	36.000	35.376	.312	119.0	425.9	113.097	111.137	982.7	34.98	5569.0	309.4	12.62	6.8257	51.0595
			36.000	35.250	.375	143.0	422.9	113.097	110.741	975.9	41.97	6659.0	369.9	12.60	6.7771	50.6964
	STD.		36.000	35.188	.406	154.0	421.4	113.097	110.546	972.5	45.40	7191.0	399.5	12.59	6.7533	50.5182
			36.000	35.124	.438	166.0	419.9	113.097	110.345	968.9	48.93	7737.0	429.8	12.57	6.7288	50.3347
36			36.000	35.062	.469	178.0	418.4	113.097	110.151	965.5	52.35	8263.0	459.0	12.56	6.7050	50.1571
		20	36.000	35.000	.500	190.0	416.9	113.097	109.956	962.1	55.76	8786.0	488.1	12.55	6.6813	49.9799
	XS	30	36.000	34.750	.625	236.0	411.0	113.097	109.170	948.4	69.46	10,868.0	603.8	12.51	6.5862	49.2684
			36.000	34.626	.687	259.0	408.1	113.097	108.781	941.7	76.22	11,885.0	660.3	12.49	6.5393	48.9174
		40	36.000	34.500	.750	282.0	405.1	113.097	108.385	934.8	83.06	12,906.0	717.0	12.47	6.4918	48.5621
	STD.		42.000	41.250	.375	167.0	579.1	131.947	129.591	1,336.4	49.04	10,622.0	505.8	14.72	9.2806	69.4200
			42.000	41.188	.406	180.0	577.3	131.947	129.396	1,332.4	53.05	11,474.0	546.4	14.71	9.2528	69.2100
42			42.000	41.124	.438	194.0	575.6	131.947	129.195	1,328.3	57.19	12,350.0	588.1	14.70	9.2240	69.0000
	XS		42.000	41.000	.500	221.0	572.1	131.947	128.805	1,302.3	65.19	14,036.0	668.4	14.67	9.1684	68.5800
			42.000	40.876	.562	249.0	568.7	131.947	128.416	1,312.3	73.16	15,707.0	748.0	14.65	9.1131	68.1700

SURFACE AREAS OF PIPE																					
NOMINAL PIPE SIZE	3/4	1	1 1/4	1 1/2	2	3	4	6	8	10	12	16	18	20	22	24	26	30	34	36	42
SURFACE AREAS SQ. FT./ FT.	.275	.344	.439	.497	.622	.916	1.178	1.173	2.26	2.81	3.34	4.19	4.71	5.24	5.76	6.28	6.81	7.85	8.90	9.42	10.99

Manufacturing Design and Composition of Line Pipe

Steel pipe used for natural gas piping shall meet the specifications of API 5L, ASTM A-53, or ASTM A-106 as listed in §192.7 documents incorporated by reference or to use from a previous edition of specifications it must meet the requirements of §192.144. Each specification requires certain chemical and physical tests are met by the manufacturer.

ASTM A-53 covers welded and seamless black and galvanized pipe. It is suitable for coiling, bending, welding, and general fabrication. In addition, seamless A-53 pipe can be flanged. This specification requires tensile, hydrostatic, flattening, coiling, and bending tests. Chemical analyses are also specified. Grades A (30,000 psi SMYS) and B (35,000 psi SMYS) are covered by this specification.

ASTM A-106 covers only carbon steel pipe. It can be used in high-pressure and high-temperature service as well as in forming applications. ASTM A-106 requires hydrostatic, tensile, bending, coiling, and flattening tests and calls for more complete analysis than A-53. Grades A and B are covered by this specification.

API 5L provides standards for seamless and welded pipe used in conveying gas, water, and oil in both the natural gas and oil industries. API 5L requires hydrostatic, tensile, flattening, and bending tests. Chemical analyses are also specified. Grades A and B are covered by this specification as well as Grades X-42 (42,000 psi SMYS) to Grade X-80 (80,000 psi SMYS).

Gas line pipe should be specified by Gas Engineering to assure the appropriate pipe is ordered for the particular design application. Currently Avista's welding procedures permit welding of Grade B or greater yield strength pipe.

Pipe Specification

When specifying pipe, the following information should be provided:

- Outside diameter and wall thickness
- Pipe specification and grade
- Longitudinal seam welding process
- Coating: specify bare or type of coating

Example specifications:

A) 16" x 0.250" W.T., API 5L Grade X-42, ERW, FBE coated
B) 4" x 0.237" W.T., API 5L Grade B, seamless, bare
C) 3/4" x 0.113" W.T., ASTM A-106 Grade B, seamless, FBE coated

The following grade specifications are normally used for 2-inch and larger steel line pipe:

ASTM A-53 Grade B (35,000 psi SMYS)
API 5L Grade B (35,000 psi SMYS)
API 5L Grade X-42 (42,000 psi SMYS)
API 5L Grade X-52 (52,000 psi SMYS)
API 5L Grade X-60 (60,000 psi SMYS)
API 5L Grade X-65 (65,000 psi SMYS)

Specification ASTM A-106 Grade B, ASTM A-53 Grade B, or API 5L Grade B (35,000 psi SMYS) seamless shall be used for size smaller than 2 inches.

API 5L Grades higher than X-52 are typically utilized for pipelines with high operating pressures and large diameters. API 5L Grades B through X-52 and ASTM A-53 Grade B are the most economical choices for distribution pressure. They are also more ductile and easier to work than higher yield strength pipe.
For new pipe, longitudinal seams should be specified as seamless, electric resistance weld (ERW) or double submerged-arc-weld (DSAW). Generally, all weld types are satisfactory, and consideration should be based on price. Sometimes seamless pipe is specified for station pipe to avoid tapping through a longitudinal seam.

The following are the available longitudinal seam welding processes by pipe diameter size:

3/4 inch – 2 inch	seamless
3 inch – 16 inch	electric resistance weld or seamless
18 inch – 36 inch	double submerged-arc-weld

Pressure Testing

New, replaced, or re-connected pipelines and facilities transporting natural gas must be pressure tested. Refer to Specification 3.18, Pressure Testing for minimum testing requirements.

Corrosion Protection

Steel pipeline systems must be cathodically protected. Generally, buried facilities are wrapped or coated with a protective coating that meets the requirements of §192.461. Aboveground facilities are usually painted, meeting the requirements of §192.479. A Cathodic Protection Technician should be consulted to recommend the appropriate cathodic protection system during the design stage of a new steel pipeline. Refer to Specification 2.3, Cathodic Protection.

AC Mitigation on New Steel Pipelines

During the design of a new steel pipeline, it should be determined whether it will be susceptible to detrimental effects from stray electrical currents. Things to consider are the physical location, particularly a location that may subject the new pipeline to stray currents from other underground facilities, including other pipelines, and induced currents from electrical transmission lines, whether aboveground or underground. A qualified Cathodic Protection Technician should review and recommend a design for AC mitigation where needed. Also, a qualified Cathodic Protection Technician should be present during construction, when applicable, to identify, mitigate and monitor any detrimental stray currents that might damage new pipelines. Refer to Specification 2.32, Cathodic Protection Design.

2.13 PIPE DESIGN – PLASTIC (POLYETHYLENE)

SCOPE:

To establish a uniform procedure for designing and testing plastic gas piping systems that meets applicable regulatory codes and provide a safe, reliable operating system.

REGULATORY REQUIREMENTS:

§192.59, §192.63, §192.121, §192.204, §192.321; §192.325, §192.327, §192.375

WAC 480-93-178

CORRESPONDING STANDARDS:

Spec. 2.3, Cathodic Protection
Spec. 3.13, Pipe Installation – Plastic
Spec. 3.23, Joining of Pipe – Plastic (Polyethylene) – Heat Fusion

DESIGN REQUIREMENTS:

General

New polyethylene pipelines and fittings shall meet the provisions of applicable ASTM specifications, be resistant to chemicals with which contact may be anticipated and be free of visible defects as noted in §192.59. Applicable ASTM specifications include ASTM D2513 – PE Pipe & Fittings, ASTM F1055 – Electrofusion type PE Fittings, ASTM F1924 – Plastic Mechanical fittings for PE Pipe, ASTM F1948 – Metallic Mechanical Fittings for PE pipe and ASTM F1978 – Factory Assembled Anodeless Risers and Transition Fittings for PE Pipe. Used polyethylene pipe shall not be installed.

Plastic (polyethylene) pipe and components may be used for underground construction of pipeline to operate at a MAOP not to exceed 60 psig. As material and installation costs for plastic are usually less than for steel, plastic is usually preferred for applications up to 60 psig.

Plastic pipe and components may be used for aboveground construction only as described within this specification.

The use of medium density (PE 2406/2708) and high density (PE 100/3408/4710) PE pipe is approved for use in pipe and fitting assemblies that use pipe, such as anodeless risers, transition fittings, and stick EFVs.

Plastic pipe and components can be used for mains and services up through 6-inch in diameter (PHMSA allows larger sizes, but Avista is not tooled to handle them).

Before using a new material, Gas Engineering will evaluate and approve the material by following the New Gas Material Evaluation Checklist. Following this checklist will ensure the new material meets specification and the proper training has been completed with appropriate Avista and contractor personnel.

Markings on Plastic Pipe and Components

Polyethylene pipe and components shall be marked per the requirements of ASTM Specifications D2513 & F2897. The markings shall be applied to remain legible under normal handling and installation practices.

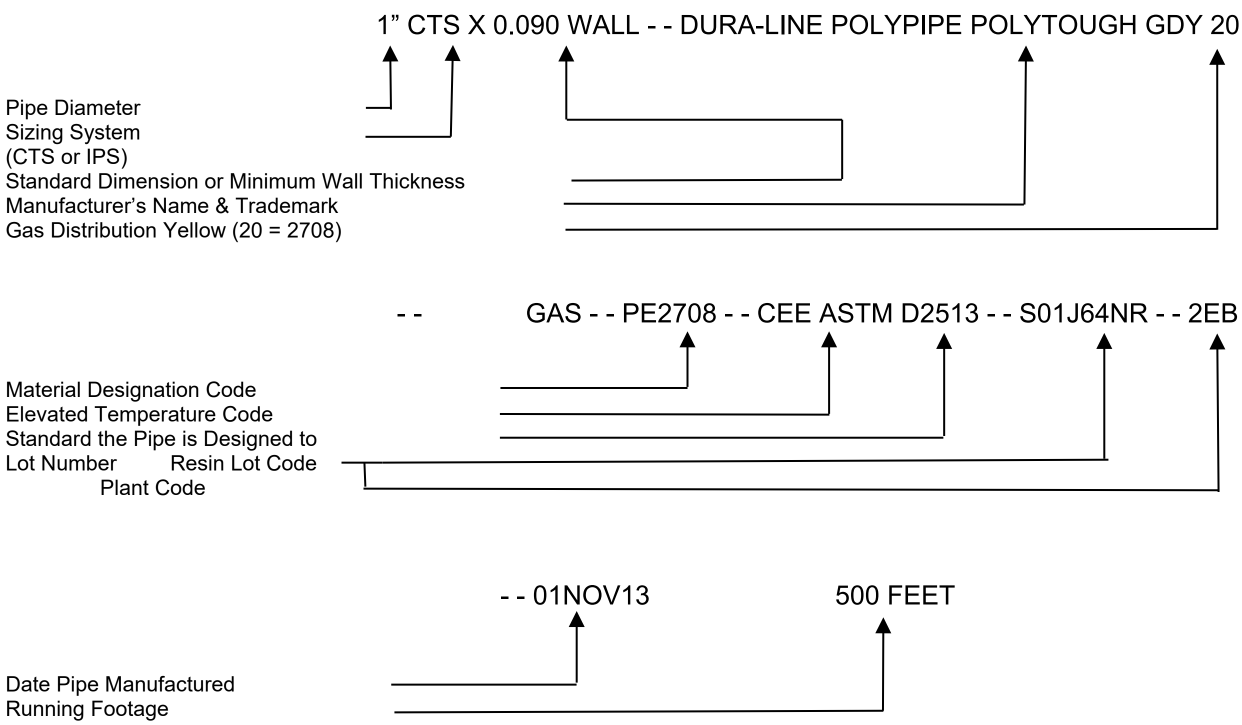
The markings on PE pipe shall be in black for yellow pipe and white for black pipe, and stenciled continuously along the length of the pipe in increments no further apart than two feet including the following information:

- Nominal pipe size (IPS, CTS, or OD)
- SDR (Standard dimension ratio) or minimum wall thickness
- Manufacturer's name or trademark
- "GAS" and "ASTM D2513"
- Material designation (PE 2406/2708, PE 100/3408/4710)
- Three additional code letters as required per ASTM D2513 (the first identifies the temperature of pressure rating; the second letter identifies the hydrostatic design basis at highest recommended temperature; and the third letter identifies the melt index). CEE or CEC is the proper code for the medium and high-density PE resins Avista is currently using.
- Appropriate code information that will enable manufacturer to identify pipe (i.e., lot number with NR (No Rework), date code, plant code etc.)
- Additional Information (i.e., coil number, feet, alphanumeric code, etc.)
- A representative 16-character tracking and traceability identifier per ASTM F2897.

Markings on plastic fittings or non-pipe components shall be marked on the body or hub of the assembly including the following information. (See print line examples below):

- "ASTM D2513" as well as the applicable fitting specification
- Manufacturer's name or trademark
- Size designation
- Material type designation
- Three additional code letters as required per ASTM D2513 (See bullet item 6 above)
- Appropriate code that will enable the manufacturer to identify date and location of manufacture, fitting production, and resin lots, and any additional information agreed upon by the manufacturer.
- A representative 16-character tracking and traceability identifier per ASTM F2897.

Pipe Print Line on Pipe Example



Design Pressure

The maximum pressure allowed for plastic piping systems is determined in accordance with either of the following formulas found in §192.121:

$P = DF \times 2S \times t/(D - t)$
$P = DF \times 2S/(SDR - 1)$

Where:
DF = Design Factor, a maximum of 0.32. A DF of 0.40 may be used if reviewed and approved by Gas Engineering in accordance with §192.121.
P = Design pressure in PSIG, (Avista max: 60 PSIG)
S = Long term hydrostatic strength in PSI. Use 1250 PSI for yellow pipe operating at less than 100 degrees F; use 1600 PSI for black pipe operating at less than 100 degrees F; use 1000 PSI for both yellow and black pipe operating between 100 degrees F and 140 degrees F (Note: Avista's 60 PSIG max design pressure for plastic pipe is based upon a 1000 PSI hydrostatic strength (up to 140 degrees F))
t = minimum wall thickness in inches
D = specified outside diameter in inches
SDR = standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness.

The following sizes and wall thicknesses of polyethylene plastic pipe are approved for use. Use of other sizes and wall thickness should be reviewed and approved by Gas Engineering:

NOMINAL	POLYETHYLENE PIPE DIMENSIONS				
SIZE IN.	SDR*	MIN. WALL THICKNESS, IN.	AVERAGE O.D. IN.	AVERAGE I.D. IN.	WEIGHT LBS/FT.
1/2 CTS (5/8 OD)	7	0.090	0.625	0.445	0.065
3/4 IPS	11	0.095	1.050	0.860	0.123
1” IPS***	11	0.120	1.315	1.075	0.193
1-1/4 IPS***	10	0.166	1.660	1.328	0.335
1-1/2” IPS***	11	0.173	1.900	1.554	0.404
2 IPS	11	0.216	2.375	1.943	0.631
3 IPS***	11.5	0.304	3.500	2.892	1.317
4 IPS**	11.5	0.391	4.500	3.718	2.176
6 IPS**	11.5	0.576	6.625	5.473	4.717

*SDR - Standard dimension ratio is calculated by dividing the average O.D. of the pipe by the minimum wall thickness in inches.
** NOTE - Coiled 4-inch IPS and 6-inch IPS pipe may be used if an approved pipe straightener is employed.
*** Pipe sizes may be found in the field but are no longer used for new construction.

Pressure/Temperature Limitations

Under normal conditions, buried plastic pipe would not be exposed to a high temperature of 100 degrees F or greater or a low temperature of -20 degrees F or less. The only place where plastic pipe could be subjected to these extreme temperature points would be where the plastic pipe is encased in a service riser or in an above grade steel casing. Approved prefabricated service risers are designed to operate at 60 psig and in a temperature range of -20 degrees F to 140 degrees F.

Plastic pipe shall not be used where it could be exposed to a temperature of higher than 140 degrees F or a temperature less than -20 degrees F unless all of the components being installed are rated by the manufacturer for these operating temperatures.

Aboveground Plastic Pipe

Plastic pipe is typically installed below ground level, with the exception of when encased in a steel riser as part of a meter set, for a temporary bypass condition, for temporary aboveground installations / emergency repairs, and when encased on bridge crossings. For temporary aboveground installations, the plastic pipe must be protected from potential damage. The appropriate method of protection will depend on the project site and associated risk of leaving the aboveground plastic pipe unattended. Possible methods of protection include:

- Install barricades and/or fencing around the aboveground plastic pipe
- Wrap the plastic pipe in yellow caution tape
- Build an aboveground conduit casing for the aboveground plastic pipe

If the temporary aboveground plastic pipe will be in place for one week or longer, Gas Engineering should be contacted to discuss an appropriate protection plan.

In Washington State, notification of the WUTC is required if the temporary installation will exceed 30 days.

WAC 480-93-178 (6): The maximum time limit that plastic pipe may be temporarily installed above ground is 30 days. Plastic pipe may be installed temporarily aboveground for longer than 30 days if Avista has a written monitoring program and notifies the WUTC by telephone prior to exceeding the 30 day timeframe.

Plastic pipe shall not be installed where it would be exposed in a pit, vault, or box, except in a valve box that is installed for a plastic valve.

Bridge Crossings

Federal regulations permit installation of polyethylene pipe on bridges. Specific design considerations must be employed to assure that the plastic is installed in a safe manner. Gas Engineering shall design polyethylene pipe bridge crossings. Refer to Specification 2.15, Bridge Design, and Specification 3.42, Casing and Conduit Installation.

Plastic Pipe under Waterways

Plastic pipe should not be installed under a waterway susceptible to scouring or migration unless it is adequately protected. This can be accomplished using additional cover or by utilizing a steel casing.

Clearances and Cover

Refer to Specification 3.15, Trenching and Backfilling for the requirements of cover and clearances for plastic pipelines.

Thermal Contraction and Expansion

Pipe must be designed and installed so it and associated fittings will be free of tensile loading as a result of temperature change. Allowance must be made for thermal contraction when plastic pipe is installed on a warm day; otherwise, pipe will be in tension when it cools.

PE pipe expands or contracts at a rate of 0.00008 to 0.00010 feet for every foot of pipe subjected to a 1-degree F temperature change. Therefore, the following equation may be used to calculate thermal expansion or contraction in PE pipe:

$\delta = \alpha\,(L)(\Delta t)$

Where: δ = elongation if (+) or contraction if (-) in feet
α = Coefficient of linear expansion. Use 0.00010 for PE 2406/2708, 0.00009 for PE 3408, and 0.00008 for PE 4710.
L = length of PE pipe in feet
Δt = change in temperature (°F), (+) if increase or (-) if decrease

This equates to approximately 0.08 to 0.10 feet (1.0 to 1.2 inches) of contraction/expansion of pipe per 100-foot length for every 10 degrees F temperature change. This is about 12 to 15 times greater than that of steel pipe.

Joining of Plastic Pipelines

Only approved methods of heat fusion, electrofusion or approved mechanical fittings shall be used to join polyethylene pipe. Plastic pipe may not be joined by a threaded joint or mitered joint.

The preferred method of joining for each size of pipe is as follows:

Pipe Size	Method of Joining
Mains:	
1/2" through 1-1/4"	Electrofusion
2" through 6"	Butt fusion, electrofusion
Services:	
1/2" through 1-1/4"	Mechanical fitting
2"	Butt fusion, electrofusion, mechanical fitting
3" through 6"	Butt fusion, electrofusion

Polyethylene to steel transition joints may be made where MAOP of steel system is 60 psig or less. The transition joint must be made using approved transition fitting. Install a protective sleeve over the fitting to provide support from external forces. Refer to Specifications 3.23, Joining of Pipe – Plastic (Polyethylene) – Heat Fusion; 3.24, Joining of Pipe – Plastic (Polyethylene) - Electrofusion, and 3.25 Joining of Plastic – Plastic (Polyethylene) – Mechanical.

The use of an insert stiffener is required with mechanical type transition fittings. The gasket material in the fitting must be compatible with the pipe material.

Cathodic Protection

Steel portions of a plastic system (any valves, risers, and other pressurized steel components) must be cathodically protected either off tracer wire or by use of an anode. Refer to Specification 2.32, Cathodic Protection. These are considered short isolated sections of steel that require monitoring. Reference Specification 5.14, Cathodic Protection Maintenance.

Tracer Wire

Solid type coated locating wire (minimum AWG #12) shall be installed with polyethylene pipe since it is not locatable on its own. Horizontal Directional Drill (HDD) installs shall be installed with a tracer wire as well (minimum AWG #10 should be used). Refer to Specification 3.13, Pipe Installation – Plastic (Polyethylene) Mains, subsection Tracer Wire for details on installing tracer wire. Electric continuity should be maintained at all wire connections. Wire connections are to be formed by use of Avista-approved connectors and/or crimping tool or other approved methods. Refer to Drawing A-36277 and subsection Wire Connections in Specification 3.13, Pipe Installation – Plastic (Polyethylene) Mains.

Consideration should be made to install a Little Fink at the end of a main to make access to the locating wire easier. Refer to Drawing B-36271, Test Stations, in Specification 2.32, Cathodic Protection Design.

2.14 VALVE DESIGN

SCOPE:

To establish a uniform procedure for gas valve selection and installation.

REGULATORY REQUIREMENTS:

§192.145, §192.179, §192.181, §192.193, §192.363, §192.365, §192.381, §192.385

WAC 480-93-100

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design - Steel
Spec. 2.13, Pipe Design – Plastic
Spec. 2.23, Regulator Design
Spec. 3.16, Services
Spec. 5.13, Valve Maintenance

DESIGN REQUIREMENTS:

General

In general, plastic (polyethylene) valves are installed on polyethylene pipelines and steel valves are installed on steel pipelines. Polyethylene valves may only be used for applications where system MAOP is 60 psig or less.

Each steel valve must meet the minimum requirements of API 6D, or an equivalent national or international standard that provides an equivalent performance level. Each polyethylene valve must meet the minimum requirements stipulated in nationally recognized standards specific to PE valves in a gas system.

Valves used must be pressure tested to withstand shell and seat pressures to not less than 1.5 times the maximum service pressure rating. Valve shell and seat tests are normally conducted by the manufacturer. The valve must have a maximum service pressure rating for temperatures that equal or exceed the maximum service temperature.

No valves shall be installed or reused other than carbon steel, stainless steel, or polyethylene valves. Neither ductile iron valves nor cast iron valves shall be installed or reused.

When installing steel valves, weld-end types are preferred over threaded or flanged valves since they are less prone to leakage.

The valve and its operating device must be accessible and protected from tampering and damage. Underground valves shall be installed in valve boxes or vaults. A marker ball should be installed adjacent to the valve box on the north side and buried at, or just below, the valve box top, giving adequate cover to the ball of about 12” to 18”. Aboveground valves, except service riser and meter set outlet valves, should be installed with locking assemblies or with valve handles removed or secured in locked stations or buildings. Except for abnormal conditions, service riser and meter outlet valves should not be locked.

VALVE TYPES

The following are the primary types of valves used in Avista's facilities. For a more complete description of valve types and how they are operated and maintained, refer to Specification 5.13, Valve Maintenance.

Steel Plug Valves

Steel plug valves historically make up the majority of the existing valves in steel gas distribution systems. These quarter-turn valves have a reduced flow port in a conical plug and are no longer the valve of choice for new construction or as a replacement valve because they require injection of grease to maintain proper seal and torque. Plug valves 6-inch and larger may require special gearing to aid operation.

Steel Gate Valves

Steel gate valves are the valve of choice for buried high-pressure applications. They are designed so that a threaded stem with a steel gate or conical end travels downward and seats in a receptacle to shut off the flow of gas. These rugged and durable valves have a full open flow port and do not require lubricating sealants. Steel gate valves require multiple turns to operate and as a result of this have low operating torques. They are also significantly less expensive size-for-size than comparable heavy-duty plug valves and ball valves.

Steel Ball Valves

Modern ball valves do not need lubricating and are designed so that gas flows through a machined ball. The port is full open when the valve is cycled by a quarter-turn, making them ideal for use in regulator station designs. Such valves, however, should not routinely be used in throttling applications. In applications where a trunnion-mounted ball valve will have high differential pressures across it, a small bypass should be considered to equalize the pressure across the valve prior to opening; this will prevent damage to valve seats. In applications intended for throttling or blowdown valves, where pressure cannot be equalized, a plug valve or gate valve should be considered. Approved stock-item ball valves may be used in buried intermediate pressure applications. <u>Care must be taken, however, to assure stem torque ratings are sufficient for buried use</u>. Except for ¾" valves used for farm tap station inlet piping, steel ball valves shall not be used in buried high-pressure applications without the approval of Gas Engineering.

Polyethylene Valves

Polyethylene valves are either of ball or plug design and are used in plastic distribution systems. They are quarter-turn type and require minimal torque to operate. These valves do not need lubricating and shall <u>not</u> be used aboveground or in a vault. Polyethylene valves shall only be installed using a butt fusion, spigot, and sleeve fittings (if the fitting can be installed per the manufacturer's instructions), or an electrofusion process. Other mechanical fittings are not approved for the installation of PE valves.

Service Line Valves

Each service line valve (commonly known as a riser valve) shall be designed to prevent removal of the valve core, except by use of specialized tools. Each service line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter. Each service line must have a shutoff valve in a readily accessible location that, if feasible, is outside the building. The customer may install a fence around the meter set to limit public access and reduce the possibility of vandalism. If locked, an Avista pad lock must be used to allow Avista personnel access to enter the area. The fence must allow sufficient room for maintenance activities to occur and should be installed after consultation with the Gas Meter Shop or the local district office, as applicable. Avista reserves the right to request removal of the fence if the aforementioned conditions of installation are not met.

Excess Flow Valve Performance Standards

Excess flow valves (EFVs) are to be installed per the requirements discussed in Specification 3.16, Excess Flow Valves. The valve must meet the manufacturer's standards and industry specification to ensure:

1. The valve will function properly up to the maximum operating pressure to which the valve is rated;
2. The valve will operate for all reasonably expected temperatures for the operating area;
3. At pressures $\geq$ 10 psig:
   The valve will close at or not more than 50 percent above the rated closure flow rate specified by the manufacturer; and upon closing, reduce the flow of gas thusly:

   a) For an EFV designed to allow pressure to equalize across the valve – allows no more than 5 percent of the manufacturer's specified closure flow rate, up to a maximum of 20 CFH, or

   b) For an EFV designed to prevent equalization, allows no more than 0.4 CFH;

4. The valve does not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

An EFV must meet the applicable requirements of subparts B and D of 49 CFR, Part 192. The valve must be marked or the presence of an EFV on the service line must be identified. The EFV must be located as near as practical to the fitting connecting the service line to the main.

Additionally, an EFV should not be installed on a service line where there have been prior problems with contaminants in the gas stream that could cause the valve to malfunction or interfere with the removal of liquids from the line for necessary maintenance.

Curb Valves (Underground Service Valves)

Underground service line valves or "curb valves" shall be installed on all services where meter sets are installed inside buildings or where it is impossible to provide ready access to a service line valve (riser valve) at the outside wall of a building. A curb valve shall also be installed on all new or replaced service lines where the installed meter capacity is greater than 1000 CFH and an EFV will not be installed. These curb valves will be considered secondary valves in most cases, see the next subsection, "Emergency Curb Valves" for exceptions. Curb valves should be located as close to the source main as possible. Consideration should be given to locating the valve so that it will be accessible at all times.

Emergency Curb Valves

Curb valves are considered Emergency Curb Valves when installed on services to buildings in which it would be difficult to quickly evacuate such as churches, schools, hospitals, jails, and convalescent homes, regardless of the size and pressure of the service line. Additionally, if the meter set is located inside with no outside riser valve, the curb valves shall be designated as an Emergency Curb Valves. Emergency Curb Valves are subject to maintenance on the schedule outlined in Specification 5.13, Valve Maintenance.

> **WAC 480-93-100 (2):** In the state of Washington emergency curb valves shall be installed (in addition to the criteria listed above) regardless of pressure, for these locations:
>
> - Service lines 2-inch in diameter and larger to commercial and industrial buildings
> - High occupancy buildings of more than 4 stories which would be difficult to quickly evacuate, regardless of the service line length or pressure.
>
> ***Note: WAC 480-93-100 (2)*** *The requirement above outlines the results of Avista's consideration of the criteria outlined in WAC 480-93-100 (2) (a through f). The sites noted in paragraphs (a through f) of the WAC have been considered as locations for valve installation. The above guidelines are the result of that consideration and are in addition to Avista's stated guidelines within this Specification.*

Valves at New Housing Developments

When designing a gas distribution system for a new housing development or subdivision, consideration should be given for installing a valve at the entrance to the development or subdivision. The valve will allow for quick isolation of gas if an incident were to happen in the subdivision.

Criteria for Determining Emergency Operating Plan (EOP) Valves

An EOP valve is a type of emergency valve that is used to divide large gas distribution systems into more manageable zones. Each transmission and distribution system must have specially designated valves, spaced to reduce the time to shut down a section of main in an emergency. Emergency valve spacing is determined by the operating pressure, the size of the mains, and local physical conditions of the area (rural, urban, business districts, and areas with predominately high-rise buildings as in a Class 4 location for instance). Sectionalizing an area, using EOP valves, should be considered based on the number of customers and the manpower needed for restoration in a reasonable timeframe (i.e., 24-hour period). Refer to Section 5, Emergency Shutdown and Restoration of Service, in the Gas Emergency and Service Handbook for further guidelines.

Tying EOP Zones Together

When designing main extensions and reinforcements, it is vital to consider where EOP zones may exist and to be aware of conflicts that may arise by joining EOP zones together. Whenever designing reinforcement projects, valves should be installed between the new and old pipe systems and the local Compliance Specialist shall be notified. Additionally, when designing main extensions, consideration must be given to the placement of valves to ensure EOP zones are not adversely impacted.

Emergency Regulator Station Valves

Each regulator station serving more than two service points must have a valve installed on the inlet piping at a distance from the regulator station (50-feet preferred, 20-feet minimum) sufficient to permit the operation of the valve in an emergency and designated as an emergency valve. Consideration should be given to installing a similar valve on the regulator station outlet piping. Gate stations should always have outlet valves. Operations personnel should coordinate efforts and work with Gas Engineering as appropriate to ensure that applicable emergency valves are prioritized for installation where they are required as noted above or would promote improved system safety or reliability.

Farm tap regulators (sometimes referred to single service farm taps) should also have consideration for inlet and outlet valves. The inlet valve should be designated as a secondary valve unless there is an extenuating reason to designate it as an emergency valve (e.g., the farm tap serves a school, church, hospital, limited mobility occupant structure, commercial building, industrial building or other high occupancy structure, or area.) This emergency / secondary valve designation guidance is a requirement in Washington per WAC 480-93-100(3) and a best management practice in Oregon and Idaho.

Transmission Line Valves

Each transmission line must have sectionalizing block valves spaced as follows:

Population Class	Minimum Spacing of Valves
Class 4	5 Miles
Class 3	8 Miles
Class 2	15 Miles
Class 1	20 Miles

Each main line valve installed in a transmission pipeline shall be full opening to allow for the passage of internal inspection devices.

Each section of a transmission line between block valves must have a blow-down valve with enough capacity to allow the transmission line to be blown down as rapidly as practical. Each blowdown discharge must be located so the gas can be blown to the atmosphere without hazard to nearby structures and overhead electrical lines.

Refer to Specification 2.12, “Transmission Lines – Design of Pipe and Components” for more information related to design criteria and records documentation requirements.

For transmission pipelines installed or entirely replaced after April 10, 2023, that meet the requirements below, Rupture Mitigation Valves (RMVs) must be installed.

- Diameter greater than or equal to 6 inches; and
- Located in Class 3 or Class 4 or HCA; or
- Located in Class 1 or Class 2 area with a PIR greater than 150 feet (See Transmission Integrity Management Program (TIMP) manual for PIR values of transmission pipelines).

Rupture Mitigation Valve (RMV) Requirements

RMVs, or alternative equivalent technology, must be installed upstream and downstream of any new or replaced Class 3 or Class 4 or HCA pipeline segment. If there is a crossover or lateral tied into the segment between RMVs, then the crossover or lateral pipe must also have a valve, such that, when all valves are closed there is no flow path for gas to be transported to the rupture site. Multiple Class 3 or Class 4 or HCA segments may be contained within a single shut-off segment. The shut-off segment shall have valves spaced as follows:

Population Class	Minimum Spacing of Valves
Class 4	8 Miles
Class 3	15 Miles
Class 2	20 Miles
Class 1	20 Miles

For laterals extending from shut-off segments that contribute less than 5 percent of the total shut-off segment volume may have RMVs, or alternative equivalent technologies, at locations other than the mainline connection point, as long as all laterals contributing gas volumes to the shut-off segment do not contribute more than 5 percent of the total shut-off segment gas volume based upon maximum flow volume at the operating pressure. For laterals that are 12 inches in diameter or smaller, a check valve may be installed at the mainline to meet this requirement if it allows gas to flow in one direction and automatically prevents gas from flowing in the direction of the shut-off segment. The check valve must be inspected, operated, and remediated at least once every calendar year not to exceed 15 months. Avista will be required to develop and implement maintenance procedures for the check valve and notify PHMSA in accordance with 192.18 if a check valve is chosen over an RMV for lateral isolation.

If an alternative equivalent technology is chosen over an RMV, PHMSA must be notified in accordance with 192.18. A technical and safety evaluation shall be included in the notice to PHMSA, and all alternative equivalent technologies must meet the requirements of 192.634 and 192.636. Alternative equivalent technologies may include a manually operated shut off valve, but it must be demonstrated that installation of an RMV would be economically, technically, or operationally infeasible in the notification to PHMSA. In addition, operating procedures would need to be developed and implemented that appropriately designate and locate nearby personnel to ensure valve shut-off in accordance with the timing requirements of 192.636 and must account for the following without exceeding the maximum response time allowed:

- Time for assembly of necessary operating personnel
- Acquisition of necessary tools and equipment
- Driving time under heavy traffic conditions and at the posted speed limit
- Walking time to access the valve
- Time to shut off all valves manually

Valve Numbering

Valve numbering shall be shown within the Avista's AFM (GIS) system. New valves shall receive new numbers at the time of installation. If a valve is being changed out / replaced in the same physical location, it should maintain the same valve numbering. If a valve is being changed out / replaced and installed at a new location, whether to renumber or not shall be at the discretion of the local operations manager based on EOP Plan considerations. Refer to Spec. 5.13, Valve Maintenance, "Valve Disable / Abandonment" for further guidance on the difference between disabling and abandoning a valve.

Installation

Valves installed on a main for operation or emergency purposes must be placed in a readily accessible location. The operating stem must be readily accessible. Valve boxes, when utilized, shall be installed so as to avoid transmitting external loads to the main. Valve box lids should be easily removable and painted yellow. Cathodic protection wires, if required, should be installed in such a way that they will not be damaged by the use of a valve key, including installing the wires on the outside of the valve box bottom. For future use of the wires, they should be left long enough so 36" of wire can be pulled from the valve box.

Generally, mainline valves installed within Avista's facilities should be in the open position unless there is a specific reason for them to be closed, for example for pressure zone isolation. This includes valves that are installed in pipe "pup" locations for future use. These valves should be open so that if the downstream pipe is damaged, that damage will be evident and can be repaired immediately.

For aboveground installations, consideration should be given to orienting the valve, so the stem is in the horizontal position. This will help prevent water from entering the valve.

Weld end ball or plug valves should always be placed in the open position when welding. This will keep the weld splatter off the ball or plug. Weld end gate valves should always be placed in the closed position when welding. This will keep the weld splatter out of the seat.

Valve Supports

Transmission and distribution line valves shall be supported to prevent settling of the valve or movement of the pipe to which it is attached. If the valve is installed in a buried box or enclosure, the box or enclosure must be installed as to avoid transmitting external loads to the main.

Each valve installed in plastic systems must be designed to protect the plastic material against excessive torsional or shearing loads when the valve is operated.

Corrosion

Buried steel valves must be externally coated or wrapped. Isolated steel valves within plastic systems require additional cathodic protection. Refer to Specification 2.32, Cathodic Protection Design. These isolated steel valves are considered short sections of steel and require monitoring just like any other short section of steel and must be placed on the Short Section Cathodic Ten Percent Survey. Refer to Specification 5.14, Cathodic Protection Maintenance for further guidance on this maintenance requirement.

Valve Codes

Valves listed in Avista's AFM (GIS) system are identified in the "USAGECODE" field by the following abbreviations:

E = Emergency Zone Valve: A valve that isolates an EOP zone.

I = Emergency Station Isolation Valve: The inlet or outlet valves to a regulator station, typically 25 feet to 50 feet outside of the station (Single-service farm tap inlet valves are not automatically considered Emergency Station Isolation Valves and may be designated as Secondary Valves.)

X = Emergency Zone and Station Isolation Valve: A valve that is both an emergency zone valve and a station isolation valve.

A = Emergency Mainline Valve: Any other emergency valve on a main that should be designated for emergency situations. (Example: valves on either side of a bridge.)

M = Emergency Curb Valve: Those curb valves on services that must be designated as emergency valves.

P = Emergency Pressure Isolation Valve: A valve that is normally closed and separates two different pressure zones.

Y = Emergency Zone and Pressure Isolation Valve: Both an EOP zone and pressure isolation valve.

C = Secondary Curb Valve: Any other valves on services that are not used for emergencies.

S = Secondary Mainline Valve: Any other valves on mains that are not classified as any of the above and are not used for emergencies.

2.15 BRIDGE DESIGN

SCOPE:

To establish general guidelines for the design and installation of natural gas lines on steel and concrete bridge structures.

REGULATORY REQUIREMENTS:

§192.159, §192.161, §192.321, §192.323
WAC 480-93-115

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design – Steel
Spec. 2.13, Pipe Design – Plastic
Spec. 2.3, Cathodic Protection
Spec. 3.42, Casing & Conduit Installation

DESIGN REQUIREMENTS:

General

Bridge designs are unique and situations involved with each design are unique; therefore, Gas Engineering shall be consulted for pipeline installations involving bridges.

Bridge crossing designs often include the use of hangers, seismic bracing, expansion joints, and other special design features. Federal regulations permit the installation of either steel or polyethylene pipe on bridges. Specific design considerations must be employed to assure that the polyethylene pipe is installed in a safe manner.

Pipeline Installation

Pipelines installed on a bridge structure shall be placed so as to allow for future inspection of hangers, seismic bracing, pipe, expansion joints, etc. Ideally, the pipe will be installed within the outermost girders on the downstream side of the bridge. This allows for easy inspection while protecting the pipe from stream flows, effects of sunlight and damage from traffic. This will involve coordination with responsible parties to allow for manhole and crawl space access within bridge structures.

On new bridges, construction arrangements shall be made to provide suitable openings or advance placement of casing or pipe through the structure and abutments of the bridge. Pipe support structures on either new or existing bridges must be coordinated closely with the agency responsible for the bridge. The pipe support design should provide for future increases in pipe size wherever practical.

Permits

When a pipeline crosses state highway bridge structures, an application must be made for an encroachment permit. The permit application shall comply with current State Department of Transportation requirements. Permit applications for other than state highway crossings shall be obtained from the responsible government agency.

Design Requirements

Pipe wall thickness shall be chosen to allow for hoop, bending, and torsional stresses due to temperature change, pressure, weight of pipe (including weight of water if carrier pipe is to be hydrostatically tested on the bridge), and any movement of or stresses caused by the configuration of the bridge. Pipe wall thickness shall be as required to meet required stress calculations.

Thermal expansion forces and stresses shall be considered for bridge spans over 100 feet. Reference Specification 2.12, Pipe Design - Steel. It may be necessary to compensate for thermal expansion by the use of approved expansion fittings or by use of pipe fittings using "U" or "L" pipe bends.

Stresses due to temperature should be based on a temperature range of -20 degrees F to 110 degrees F. As both allowances for thermal contraction and thermal expansion need to be considered, calculations need to be based on probable temperature variations from the temperature at time of construction. Maximum hoop stress due to internal gas pressure shall not exceed 40 percent of SMYS of the carrier pipe. When possible, the pipeline should be designed so that the hoop stress is less than 20 percent of SMYS. Use of isolation valves should be considered at both ends of bridge, outside of the bridge structure, to allow isolation of the pipeline on the bridge structure.

Supports

Care should be taken in selection of supports, hangers, brackets, rollers, and pads. Allowance must be made for the casing and carrier pipeline to expand and contract at a different rate than the bridge, yet be restrained and supported satisfactorily.

Seismic Supports

In seismic prone areas, pipe supports and hangers should be designed to withstand seismic forces. In addition to static loads of pipeline systems, use an additional 0.2g for vertical seismic force and 0.3g for horizontal seismic force (i.e., supports and hangers must be able to withstand 120 percent of load weight of pipeline system in the vertical direction and 30 percent of load weight in the horizontal direction). Reference Specification 2.12, Pipe Design – Steel.

Corrosion Protection

Carrier pipe shall be electrically isolated from the bridge structure and support components through the use insulated fittings on pipe hangers and support hardware. Steel carrier pipe and weld joints shall be coated with an approved coating. Coating on exposed carrier pipe should be UV resistant paint or tape wrap. Exposed hanger hardware shall be hot-dipped galvanized, stainless steel, or other atmospheric corrosion-resistant coating.

Casings

Some governing agencies require natural gas pipelines on bridges to be steel cased throughout the length of the structure. If a casing is used, the space between the pipe and the casing must be effectively open to atmosphere preferably at both ends, but at least on one end, using either a vent pipe or other satisfactory type vent to avoid unsafe build-up of pressure in the casing due to leakage of the carrier pipe. Reference Specification 3.42, Casing & Conduit Installation. Casing insulators, end seals, and vents shall be installed as detailed in Specification 3.42, Casing & Conduit Installation.

2.2 METERING & REGULATION

2.22 METER DESIGN

SCOPE:

To establish a uniform procedure for designing and installing metering equipment.

REGULATORY REQUIREMENTS:

§192.351, §192.353, §192.355, §192.357, §192.359.

WAC 480-90-323, 480-90-328, 480-93-140

OTHER REFERENCES:

International Fuel Gas Code (IFGC), Sec. 401.7
National Electric Code (NEC), Article 500, 501, and 504

CORRESPONDING STANDARDS:

Spec. 2.14, Valve Design
Spec. 2.23, Regulator Design
Spec. 2.24, Meter & Regulator Tables & Drawings
Spec. 3.16, Services
Spec. 5.12, Regulator and Relief Inspection

DESIGN REQUIREMENTS:

General

The amount of natural gas a customer consumes must be measured as it is delivered to the customer primarily to provide information for billing. This measurement is accomplished by a gas meter, and it is important to have knowledge and understanding of the gas meter and the various components associated with metering as follows in this section.

Avista's metering and regulating equipment shall be installed, operated, and maintained in accordance with federal and state regulations, and in accordance with the manufacturer's recommended installation and maintenance practices.

> **WAC 480-93-140(1)** – To ensure proper operation of service regulators, each gas pipeline company must install, operate, and maintain service regulators in accordance with federal and state regulations, and in accordance with the manufacturer's recommended installation and maintenance practices.

Existing meter set designs that do not currently conform to this specification should be brought up to standard when there is an opportunity to do so with some reasonable exceptions. Refer to GESH Section 7 - Meter Turn on Orders, "Bringing Meters up to Standard" for further guidance. Existing inside gas meters should, where possible, be relocated outside when the customer piping is revised, altered, or if another opportunity exists.

Meter Types

Common types of gas meters used in the system are as follows:

Aluminum and Iron Case Diaphragm Meters: These meters are positive displacement meters and measure a known quantity of gas by filling and emptying chambers within the meter. This is the most common type of meter; residential meters are of this kind.

New diaphragm meters are aluminum cased. Iron case meters are being phased out of the system because they are no longer manufactured and are large, heavy, and cumbersome to maintain. Many of the large diaphragm meters, aluminum, and iron, are being replaced with rotary meters due to their size and difficulty in keeping them accurate as they age. Currently, however, both types are still active in the system.

Rotary Meters: The rotary meter is a positive displacement meter that measures gas with two oppositely rotating figure 8 impellers operating within a rigid casing. Rotary meters are typically used for commercial and industrial loads. Rotary meters are smaller and lighter weight than their diaphragm counterparts and are replacing them in the field.

Turbine Meters: As gas enters a turbine meter inlet, it exerts a force on the turbine rotor blades that turns the rotor at a speed directly proportional to the gas flow rate that is measured by the index. Turbine meters are used primarily for large commercial and industrial loads and for metering at Gate Stations.

Ultrasonic Meters: Ultrasonic meters operate using ultrasound-based flow measurement with little to no pressure drop across the meter. Ultrasonic meters typically have high accuracy flow measurement with a large capacity and range. Ultrasonic meters are not currently installed in Avista's system and are primarily located at Gate Stations on the Interstate side of the custody transfer.

Coriolis Meters: Coriolis meters operate by measuring the mass flow rate of natural gas through a tube per unit of time. The mass flow rate is then divided by the fluid density to determine the volumetric flow rate at a measurement location. Coriolis meters are not currently installed in Avista's system and are primarily located at Gate Stations on the Interstate side of the custody transfer.

Meter Identification

Meters must have a unique serial number and a tag or sticker identifying the utility's name. An updated name tag or sticker must be installed on meters within three years of a company name change in accordance with WAC 480-90-328.

WAC 480-90-328 - Meter Identification. – Gas utilities must identify each meter by a unique series of serial numbers, letters, or combination of both, placed in a conspicuous position on the meter, along with the utility's name or initials. Utilities must update the name or initials on its meters within 3 years of a name change.

Meter Case Pressures

A manufacturer's shell test pressure on a meter must be at least 1.5 times the maximum operating pressure of the meter. Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 psig. A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing. A meter may not be used for pressures above the rated pressure of the meter. Reference the "Meter Capacity Tables" under Specification 2.24, Meter & Regulator Tables & Drawings, for further information.

Meter Set Location, Protection, and Barricades

The meter and service regulator must be installed in a location readily accessible for examination, reading, replacement, and maintenance. The meter location shall provide protection from damage due to outside forces including but not limited to vehicles, weather, snow, and ice. When proper meter protection cannot be provided by placement of the meter, secondary protection shall be provided. Customers may install protective fences around meters as long as they comply with Avista's requirement for access and maintenance. Refer to Specification 2.14, Valve Design, "Service Line Valves" for further information.

Ideally, the meter set should be located so that the service line route is the shortest route between the gas main and the meter set location. Where feasible, the meter and regulator should be located outside the building at the building wall, unless located in a separate metering or regulating building or fenced area. When multiple regulators are used, the upstream regulator in a series must be located outside the building unless it is located in a separate metering or regulating building.

Meter sets must be installed in one of the following locations (listed in order of preference).

1. Outside, at or near ground level, adjacent to an exterior wall of the building. In heavy snow areas the meter shall be installed under a roof overhang of 12 inches (minimum) measured from the drip line to the front face of the meter or on the gable end of the building where possible. On new installations, if this is not possible, approved external meter protection and a breakaway fitting should be considered for installation to protect the meter from falling snow and ice, see "Breakaway Fitting" in this Specification for more information. Refer to Specification 3.16, Services, "Services in Heavy Snow Areas", for additional guidance.
2. In an alcove in the exterior wall of the building.
3. In a meter room (or meter rooms) within the interior of the building.

Should it be necessary to install the meter set in an alcove or a meter room(s), special design considerations must be met as detailed in the "Inside Meter Set" section of this specification.

A meter that is installed more than 3 feet from the wall of a building served by gas shall be considered a "Remote Meter Set". These installations are not preferred but may be necessary at mobile home parks or in other special circumstances. All remote meter set installations not serving a mobile home shall be approved by Gas Engineering. Remote meter sets are more prone to vehicular damage and can be obstructed by vegetation. These meter sets shall be flagged in Avista's (GIS) AFM system or the asset management system for tracking per WAC 480-90-323.

WAC 480-90-323 – Meter Set Assembly Location. – When it becomes necessary to locate meters away from the building wall or inside buildings, the gas utility must keep a record of these meter set assemblies, including in such record the location, installation date, and leak history. Utilities must submit copies of such records to the commission upon request.

The following should be considered (listed in the order of preference) when locating a meter and ensuring adequate meter protection:

1. Use of the proposed or existing structure, such as under a building eave or other appropriately designed architectural feature, to provide protection from weather, ice, or snow, or outside forces.
2. Installation of an excess flow valve (EFV) and a breakaway fitting to reduce the consequences if a meter is damaged, see “Breakaway Fitting” in this Specification for more information. Residential EFV’s shall be installed per Specification 3.16, Services. (Oftentimes, an EFV may be a preferred method of providing snow protection as it cannot be removed by the customer.) As noted in Specification 3.16, EFV’s must be located as close to the fitting connecting the service line to main as practical.
3. Secondary structure - A secondary structure, sometimes referred to as a snow shed, shall be installed at the time of the meter installation by Avista. The structure shall be per Avista specifications.

When protection from vehicle or other outside force damage (other than snow) cannot adequately be provided, secondary protection such as a breakaway fitting or a meter barricade shall be installed by Avista; see “Breakaway Fitting” in this Specification for more information. A barricade and breakaway fitting can be installed together to provide an additional level of protection. The barricade shall be installed as detailed in Specification 2.24, Drawing A-36712, or according to a Gas Engineering approved equivalent design. A 2-inch diameter barricade may be used only in residential applications. A 4-inch diameter barricade should be used in commercial applications, in areas where two-way vehicle traffic is expected or when additional protection is deemed necessary based on site conditions. It is preferred that barricades be installed at least 6 feet from primary voltage electric equipment (greater than 600 volts). The “swing radius” of equipment doors must be taken into consideration in the “6-foot rule”. If a barricade is required within 6 feet of primary voltage electric equipment, the barricade shall be one of the following:

- Non-conductive bollard
- Steel bollard with non-conductive sleeve
- Steel bollard bonded to electrical equipment ground

In areas that experience heavy snowfall the meter should be installed on the gable end of the building to protect the meter from falling snow and ice from the roof. Areas prone to heavy snowfall include the following counties: Bonner (ID), Boundary (ID), Klamath (OR), Klickitat (WA), Kootenai (ID), Lake (OR), Latah (ID), Lincoln (WA), Shoshone (ID), Spokane (WA), Stevens (WA), Union (OR), and Whitman (WA).

If the meter cannot be installed on the gable end of the building or if the meter is located under a roof overhang whose drip line is less than 12 inches from the front face of the meter, a breakaway fitting and a meter cover should be considered for installation to protect the meter. See “Breakaway Fitting” in this Specification for more information. Company provided “snow sheds” are the preferred option, but the customer may choose to install their own cover. Snow breaks on roofs are not an acceptable option for meter protection. Customers who elect to install their own cover are responsible for the design and construction of the cover. The design of the cover must be stamped by a professional engineer and approved by Avista. Covers shall be structurally sound and installed in a manner that does not interfere with the inspection, maintenance, and replacement of the meter.

Anchoring of the snow sheds in a “fixed foundation”, such as concrete, should occur. Guidance on concrete anchoring is as follows:

- Use one 80# bag of concrete
- Divide the dry concrete mix between the four holes dug for the posts of the snow shed
- Add a quart of water per hole and mix
- Place excavated soil on top of the concrete filled holes to prevent quick drying of the concrete
- Level the placement of the shelter before the concrete cures

Design requirements for customer provided snow covers are as follows:

1. Be designed to withstand a uniform pressure of 500 pounds per square foot distributed over the top surface of the structure. The snow shed must not deform or fail under this design load.
2. Have a minimum of 12 inches of clearance between the top of the meter set and the snow shed shall be provided.
3. Must cover the entire width of the meter set, with an additional 8 inches (minimum) on either side to allow accessibility for maintenance.
4. Must be corrosion resistant, through the use of galvanized metals, paint, or other corrosion resistant materials.
5. Must be free standing and cannot be attached to the meter assembly in any way.
6. Shall allow for natural ventilation to mitigate accumulation of natural gas.
7. Must provide a minimum of 8 inches of overhang, measured from the front face of the meter.

When the operating district is made aware of existing situations where the meter set is subject to possible damage, Avista will provide meter protection at the Company's expense.

In addition to minimum location requirements as outlined in Drawing A-36275, meter sets should not be installed in the following locations:

1. Locations subject to snow or water shedding off a roof.
2. Locations subject to corrosion.
3. Locations subject to vehicular damage such as adjacent to driveways.
4. Locations subject to ground erosion or places subject to excessive vibration.
5. Locations subject to condensation or where live steam, hot liquid, or corrosive gases or vapor are present or used.
6. Locations under or within any porch, deck patio or similar enclosure where access is limited, and the free venting of gas is not assured.
7. Locations under interior stairways.
8. In engine, boiler, heater, or electric meter rooms.
9. Under outside fire escapes.

Breakaway Fitting

A breakaway fitting should be installed on a new or existing meter set where damage may occur due to outside forces including, but not limited to, vehicles, snow, ice, and ground settlement. A breakaway fitting may not be used as an alternative to an EFV, curb valve, or a snow shelter. In situations where a bollard or snow shelter is necessary, a breakaway fitting can also be installed to provide an additional level of protection. In residential applications a breakaway fitting may be used instead of a bollard. In commercial applications a breakaway fitting may not be used as an alternative to a bollard but can be installed in addition to a bollard to provide a higher degree of protection.

The breakaway fitting should be installed downstream of the service valve, preferably directly into the outlet of the service valve. The following table shows meter set configurations where it is acceptable to install a breakaway fitting. Due to flow rate restrictions, do not install a breakaway fitting in the applications shown in gray or on any other type of meter not included in the table.

Acceptable Breakaway Fitting Applications

System MAOP	AC250 / R275		AL425			AC630		
	7" W.C.	2 PSIG	7" W.C.	2 PSIG	5 PSIG	7" W.C.	2 PSIG	5 PSIG
46-60 PSIG	✓		✓[1]	✓	✓[6]	✓[7]	✓[8]	
22.6-45 PSIG	✓	✓[2]	✓[2]			✓[9,10]		
10-22.5 PSIG	✓		✓[3,4,5]					
6-8 PSIG	✓							

[1]Install an 1813C regulator with 3/16" orifice if customer load is greater than 550 SCFH.
[2]Install an 1813C regulator with 3/16" orifice if customer load is greater than 390 SCFH.
[3]Install an 1813C regulator with 3/16" orifice if customer load is greater than 90 SCFH.
[4]Install an 1813C regulator with 1/4" orifice if customer load is greater than 380 SCFH.
[5]Install an 1813C regulator with 5/16" orifice if customer load is greater than 500 SCFH.
[6]Install an 1813C regulator with 3/16" orifice if customer load is greater than 575 SCFH.
[7]Install a CL-31-IMRV regulator with 3/16" orifice if customer load is greater than 600 SCFH.
[8]Install an 1813C regulator with 3/16" orifice if customer load is greater than 550 SCFH.
[9]Install an 1813C regulator with 3/16" orifice if customer load is greater than 400 SCFH.
[10]Install an 1813C regulator with 1/4" orifice if customer load is greater than 740 SCFH.

3 Foot Rule

For outside meter set locations, at the time of installation of the meter, the vent of the service regulator should not be located within a 3-foot radius of the following (refer to Drawing A-36275):

In PP&L territory (an electric utility within Avista's Oregon service area), the gas meter assembly shall be located no closer than 3 feet from the electric meter and associated enclosure, Refer to Drawing A-36275. (This is the one "shall" requirement of the 3-foot rule.)

- Any ignition source such as an electrical meter and associated enclosure, electric outlet, electric switch, light fixture, disconnect, circuit breaker, air conditioner condenser or heat pump, generator, and transformers
- A direct-vent appliance vent, duct, or air intake
- The combustion air vent to a 90+ efficiency heating appliance or the vent terminal
- Any non-mechanical, free flow building air vent such as a foundation vent, window, dryer vent, door, etc. unless the regulator vents above the opening in which case a 12" radius of separation is acceptable.
- Combustion air vents to fireplaces
- Any external building fire suppression system connection locations should not be within 3 feet of the closest component of the meter set (not necessarily the regulator vent).

Also, they should not be within a 3-foot radius from the opening part or side of any window that can be opened or any opening to a building or doorway. Where minimum distances cannot be maintained, care must be taken to pipe the vent of the regulator to a safe location, or the meter set should be relocated.

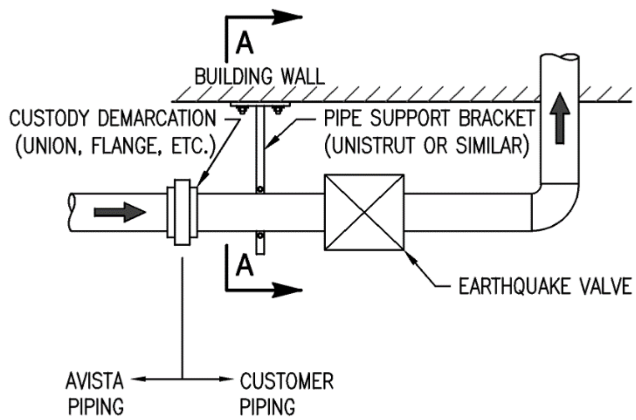
Note: Under normal operating conditions, cable television and telephone termination boxes are not sources of ignition.

10 Foot Rule

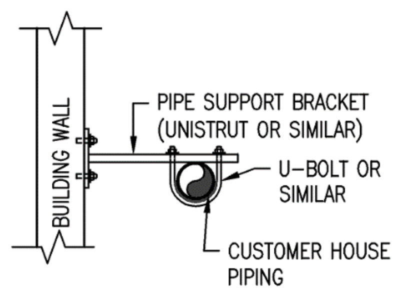
For outside meter set locations, the vent of the service regulator must be located at least 10 feet away from any active fresh air intake or combustion air vents into mechanical rooms. Refer to Drawing A-36275. Where the minimum distances cannot be maintained, care must be taken to pipe the vent of the regulator to a safe location, or the meter set should be relocated.

Earthquake Valves

Earthquake valves are devices that are designed to shut off gas flow to a facility in the event of an earthquake. Some customers may require an earthquake valve to be installed at their facility. If a customer desires to have an earthquake valve, it is the customer's responsibility to purchase, install, and maintain the valve. The earthquake valve shall only be installed on the customer owned side of the meter set, downstream of the custody demarcation point. Since earthquake valves are designed to close when movement is detected, the valve should be securely attached by the customer to the building and supported in a way that allows the meter set to be maintained and disassembled without disturbing the valve. The illustration below shows a recommended earthquake valve installation.



PLAN VIEW
SCALE: NONE



PIPE SUPPORT BRACKET SECTION A - A
SCALE: NONE

Inside Meter Sets

Installing a meter set inside a building is generally undesirable because it is difficult to read and maintain and should only be considered as a last alternative. If the meter and/or the regulator are installed within a building, they must be located as near as practical to the point of service line entrance and be approved by Gas Engineering.

In general, any meter set inside a building must be located in a ventilated place and not less than 3 feet from any source of ignition or any source of heat that might damage the metering equipment. Electronic correctors mounted on meters with or without telemetry must comply with the applicable version of the National Electric Code (NEC), Article 500, 501, and 504 for Hazardous (classified) Locations. Refer to Specification 2.25, Telemetry Design for further detail on electrical classifications.

If a meter set must be installed other than outside, at or near ground level, and adjacent to an exterior wall of the building, then the preferred location is for the meter to be installed in a building alcove.

Alcove Installation:

An alcove is a recessed area in the building's exterior wall that is sealed from the building interior and is accessed from outside the building. An alcove must have a floor, sidewalls, and a ceiling with a minimum 1-hour fire rating. Doors may be installed for aesthetic reasons (facing outward), but venting must be provided to the outside atmosphere (via louvers, decorative panels, or ventilation piping). Minimum venting requirements for each alcove door are 5 inches x 10 inches screened vent, top, and bottom.

If the pressure regulator is installed within the alcove, then the service to the regulator must not penetrate into or underneath the building.

Alcove meter locations:

- Must be dedicated to gas facilities only,
- Must not obstruct a building entrance or exit,
- Must be large enough to house the meter set(s) and/or pressure regulator assembly and provide adequate space for installation and maintenance,
- Must be at or near ground level, and
- Must be accessible at all times to Avista service personnel.

Meter Room Installation:

If an inside meter set may not be constructed in an alcove but must be within the interior of the building and accessed from within the building, then it is considered a "meter room" installation. Meter rooms must be built to Avista's specifications (Refer to attachment titled "Avista's Requirements for Gas Meter Room Installations" at the end of this specification. Inside meter sets should be installed only as a last resort. Inside meter sets must be reviewed and approved by Gas Engineering prior to installation.

Acceptable locations for meter rooms are listed below (in order of preference):

1. On the ground floor and adjacent to an exterior wall.
2. In a basement and adjacent to an exterior wall.
3. On the ground floor, located in the interior of the building, and not adjacent to an exterior wall.
4. In a basement, located in the interior of the building, and not adjacent to an exterior wall.
5. On a floor other than the ground floor or basement and adjacent to an exterior wall.
6. On a floor other than the ground floor or basement and located in the interior of the building, and not adjacent to an exterior wall.
7. A series of meter rooms stacked vertically on multiple floors.

Extended service piping necessary to reach the meter room from outside the building wall should be welded steel piping between Avista's primary pressure regulator and the inside meter (or meter headers). Extended service piping must be identified as belonging to Avista. The piping must:

- Operate at less than or equal to 5 psig within the building. Reference "Delivery Pressure" in this specification.
- Be designed and installed in accordance with the applicable regulations, as set forth in federal, state, and municipal codes,
- Be electrically isolated from underground gas facilities at the riser. Reference "Insulating Downstream Customer Piping" in this specification.
- Be vapor-proof sealed at penetration points through the exterior of the building and be designed and installed in accordance with the applicable regulations, as set forth in federal, state, and municipal codes.

Avista may contract to an approved contractor the installation of the extended service piping. An Avista representative must supervise the installation of this piping. If the extended service piping is installed without Avista's supervision, Avista reserves the right to require that the piping be replaced at the contractor's expense to ensure that it has been installed to Avista's specifications.

Acceptable locations for extended service piping are listed (in order of preference):

- In an area that is fully exposed and accessible.
- In a 1-hour fire rated chase that is fully accessible with 1-hour fire rated doors on each floor.
- In a welded steel casing approved by Avista's Gas Engineering Department that is sealed and vented to the outside atmosphere.

Each inside meter set must have a service valve, or a curb valve located outside the building wall. The curb valve must be maintained and accessible by a valve box. Reference Specification 2.14, Valve Design for more information on curb valve applications.

Service regulator vents and relief vents must be piped outdoors per "Regulator and Relief Vent Design" in this specification.

Occasionally meters and/or regulators must be installed inside a structure to avoid snow load or snow roof unloading issues. This should be a last resort and is only to be done with prior approval from Gas Engineering.

Efforts should be made to move inside meter sets outside anytime work is required on the meter, regulator, or service piping. If it is proposed to leave the meter set inside, contact Gas Engineering. Gas Engineering will review the existing installation and determine if it meets current installation requirements.

Regulator and Relief Vent Design

Service regulator vent lines up to 20 feet in length shall be of minimum 1-inch pipe or sized according to the manufacturer's instructions. Vent lines shall be constructed of minimum Schedule 40 steel or wrought pipe unless otherwise specified by Gas Engineering. Vent lines shall be properly sloped, maintaining a rise of at least 1/4-inch per run foot and properly doped and tightened to prevent moisture accumulation or the entry of water. Vent lines in excess of 20 feet shall be referred to Gas Engineering for sizing.

Vent lines shall be adequately supported. On mobile homes, vent lines should not be secured to the structure. The outside piping must be rain and insect resistant by orienting the vent pipe downward and installing a screen in the end. Vent lines must be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building. (Reference Drawing A-36275 in this specification for minimum distances.) The vent lines must be protected from damage caused by submergence in areas where flooding may occur.

Pits and Vaults

Ideally, meter sets should not be installed in pits or vaults, as they are difficult to access, tend to accumulate liquids, and often contain air of questionable quality. Each pit or vault that does house a customer meter or regulator at a place where pedestrian and/or vehicular traffic is anticipated must be able to support that traffic. For further information regarding vaults, refer to Specification 2.42, Vault Design, and Specification 5.18, Vault Maintenance.

Installation

Each meter set must be installed so as to minimize anticipated stresses upon the connecting piping and the meter. Some meter sets may require additional support. For example, an external support is required to keep rotary meters level and supported in order to function properly. A concrete pad or adjustable stand approved by Gas Engineering is needed to support the larger diaphragm meters. If a flex line is used to connect the meter set to the house line, a meter support may be required. A meter support should be installed on new installations where the individual installing the meter does not feel that compaction can be maintained and/or that settling at the meter location is likely to occur. Meter supports should also be installed on existing meter installations where there is evidence of settling causing strain on the meter set. In all cases the meter support shall be made of non-combustible material. Reference the Appendix A drawings under Specification 2.24, Meter and Regulator Tables and Drawings for further details of some frequently used supports.

Meters must be installed and should be maintained so that they are readily accessible to meter readers and meter service personnel. The meter should be facing the direction from which a meter reader would approach the meter to be read. For newly installed meters/regulators and those being brought up to standard configuration, the regulator vents shall be oriented straight downward (six o'clock position) to prevent water from entering into the regulator and causing the regulator to freeze up. Vent screens are required on the regulator vents to keep out insects and debris. If the regulator vent cannot be positioned downward on its own, then a "mushroom cap" fitting may be used, or a vented elbow fitting may be installed in the vent so that it is configured to vent in the downward position.

Only one service should be installed per customer or per building unless the building contains a firewall between customers. Reference "Multiple Services" within this specification for requirements. Meter sets should not be installed until the ground level is established as to final grade wherever possible.

When attaching the meter to flanges, tighten the bolts in an alternating sequence until the entire flange face contacts the meter. Repeat the tightening sequence until the bolts area at the specified torque. By gradually increasing the bolt torque over multiple steps, it is less likely that the flange and meter *face will* bind or become misaligned. Tighten the bolts to the following torque levels based on meter manufacturer.

Manufacturer	Torque (ft-lb)
Romet	20
Dresser 8C thru 16M (5/8" bolts)	45
Dresser 23M (5/8" bolts)	60

Overbuilds

Buildings, mobile homes, carports, and structures that might entrap gas shall not be constructed over Company gas facilities without an approved design by Gas Engineering. If an existing customer's service line or meter set must be relocated by the Company due to any change being proposed by the customer, (i.e., building construction making the meter set inaccessible, building over the service line, or any other violation of the federal, state, or local regulations), the cost of the relocation should be paid by the customer. Overbuilds that have occurred in the past should be corrected by removing the structure or relocating the overbuilt facilities. The cost for this work should be handled on a case-by-case basis.

Idle Meters

Idle meters should be removed when it is apparent gas will not be used in the future.
Refer to Specification 5.16, Abandonment or Inactivation of Facilities. An idle meter on
Rental property may remain if the marketing representative determines that another tenant may use gas in the near future.

Idle Services

Idle services have either not had a meter installed yet or the meter has been removed and the service valve has been locked off. They should be cut off at the main if it is determined that it is unlikely that gas will be used in the future. If left in place, the riser is subject to the requirements of atmospheric corrosion monitoring, Reference Specification 5.14, Cathodic Protection Maintenance to include the need to be marked with the appropriate gas pipeline sticker.

High pressure (HP) idle risers shall be properly protected and labeled. High pressure risers shall be marked with the appropriate “HP Gas Pipeline” sticker.

When reinstating a HP idle riser into service, Gas Engineering shall verify the MAOP and design appropriate regulation and metering equipment for the conditions.

Multiple Services

A building or other structure served on a single lot and/or sharing a structural component with another building (i.e., common wall, common roof, etc.) should be supplied by only one service. Zero lot-line structures are considered a single structure.

More than one service is permitted by the following exceptions. Additional services must be in a readily accessible location and shall not compromise safety or system integrity.

- Single-family dwellings are not allowed additional service points unless it is for the following exceptions:
    a. Swimming pool/spa, when there is a permanent building containing the heating equipment which is detached from the main structure. (Note: This option should only be used when it is a hardship for customer to install downstream piping.)
    b. Shops, garages, barns, and outbuildings which are detached from the main structure.
- Multiple unit residential and commercial buildings may be allowed additional service points provided that only one service feeds a unit or units located between a 2-hour firewall. Limiting service points can reduce confusion and assure that no additional gas feeds go unaccounted for in a gas emergency.
- Industrial complexes will be individually evaluated and handled on a case-by-case basis. Contact Gas Engineering in these instances.

Multiple Meters

Multiple meters (meter manifolds or meter banks) should be grouped in one accessible location wherever possible. Meter manifolds should be constructed so that different delivery pressures are separated using pipe branching to allow for ease of identification.

Gas houseline piping at multiple meter installations shall be marked by a stamped metal washer or metal tag attached by the builder or developer so that the piping system supplied by each meter is easily identifiable per the International Fuel Gas Code (IFGC), Sec. 401.7. The identifier shall be made of brass, galvanized steel, or other weather resistant metal that can be stamped with the unit number or other identification. Identifiers made of soft metals (such as aluminum) that may be subject to bending or other damage are prohibited. All tags shall be secured to the downstream piping with a metal wire of sufficient strength to prevent tampering.

Insulating Downstream Customer Piping

The customer gas piping system must be electrically insulated from the gas service piping if the service pipe is steel. This is necessary in order to maintain proper cathodic protection of the Company underground gas piping system. The following methods of insulating the customer piping from the steel service piping are used:

- Meter sets are most often installed with a service valve that is equipped with an insulating union. This is the preferred method of insulation.
- Meter sets with a non-insulating service valve should have an insulating union installed. Installation of an insulated meter swivel is also acceptable on existing meter sets.
- Large meter sets are most often insulated with an insulating gasket and insulating kit at a flange.
- Some large meter sets have an insulating type coupling on the outlet side of the gas meter.

On polyethylene (PE) plastic services, the tracer must terminate below the insulated fitting. Refer to Specification 2.32, Cathodic Protection, and Specification 3.16, Services for more information. Reference the "Standard Meter Set Drawings" under Specification 2.24, Meter and Regulator Tables and Drawings for further details.

Meter Set Design

Refer to the "Standard Meter Set Drawings" under Specification 2.24, Meter and Regulator Tables and Drawings for design of residential and commercial meter sets. These standard designs are to be used in most applications; however, they may not be appropriate for every meter set application. Gas Engineering will assist with the design of non-standard meter sets. Industrial meter sets are handled on a case-to-case basis in Gas Engineering.

Some parameters to include when designing a meter set are as follows:

- Customer's total connected load and/or expected peak load (BTU/HR)
- Customer's minimum load expected
- Customer's desired and/or required delivery pressure
- Minimum and maximum inlet pressure to the meter set
- Relief Requirements (downstream MAOP)
- Upstream MAOP for pressure rating requirements of equipment
- Upstream MAOP for pressure rating of equipment
- Required pressure differential across the regulator
- Pressure differential across the meter
- Adequate test plugs and blow down valves
- Adequate bypass valves
- Filter/Strainer requirements
- Pipe lengths required for sensing lines and meters
- Range of the meter for low flow and peak flow conditions
- Telemetry requirements such as for transport customers
- Future load requirements
- Inlet pipe size
- Outlet pipe size
- Meter set supports
- Valve locking devices
- Accessibility to meter set
- Meter set protection such as barricades, fencing, locks, and buildings
- Meter location

Note: Refer to the following paragraph on Gas Information Sheets for further reference on meter set design. Also, reference "Meter Capacity Tables" and the "Regulator Capacity Tables" under Specification 2.24, Meter and Regulator Tables and Drawings, for more information.

Gas Meter Information Sheets

Gas Meter Information Sheets for meter sets are to be filled out and submitted for approval for sizing the meter and regulator when:

- Elevated pressure is desired (Metering Pressure > 7 inches WC.)
- The load is greater than 900,000 BTU/Hr.
- Customer's load or pressure requirements change.

The sheets are to be submitted to the Gas Meter Shop in Spokane. Requests for meter sets with conditions that meet the industrial meter set definition or for delivery pressures of 5 psig or above shall be submitted to Gas Engineering for design and/or approval.

Industrial Sets and Elevated Pressure Sets

Metering pressure above 7 inches WC (1/4-inch psig) is considered elevated pressure. "Metering Pressure" is the pressure at which the gas flows through the meter and to which the volume is corrected. "Delivery Pressure" is the pressure at which the gas is served to the customer's piping. Typically, these are the same.

Requests for 2 psig meter sets with loads less than 14,600,000 BTU/hour shall be handled and approved by the Customer Project Coordinator (CPC) or the Local Construction Office. Requests for 2 psig meter sets shall include a Gas Meter Information Sheet regardless of BTU load for recordkeeping purposes.

Note: Refer to "Maintenance of Elevated Pressure Meter Sets" and "Maintenance of Industrial Meter Sets" in Specification 5.12, Regulator and Relief Inspection for pressure check requirements.

Requests for delivery pressures of greater than 5 psig or with loads greater than or equal to 14,600,000 BTU/Hr shall be submitted to Gas Engineering for review prior to making a commitment to the customer, as these are typically large commercial or industrial meter sets that may need to be specially designed and involve contracts. A gas planning analysis may need to be conducted to assure that gas is available at the desired pressure.

Requests for elevated pressure meter sets at 5 psig or greater should be considered based on the following criteria:

- Customer's equipment requires elevated pressure. (Manufacturer's equipment verification should be attached to the Gas Meter Information Sheet)
- Customer's piping requires greater than 2-inch piping for standard delivery pressure.
- Customer is adding load to an existing house line that is no longer sufficient at standard delivery pressure.

A meter set that meets any of the following conditions is considered an "industrial" set:

- A set metering at pressures above 5 psig (note: metering pressure, not delivery pressure.)
- A rotary meter size 16M or larger regardless of metering pressure
- A turbine meter
- Any set with an hourly design load equal to or above 14,600,000 BTU/Hr
- Meter Correction Code of 3 or P

Engineering Design Note: It is recommended to use fixed factor metering on sets with loads below 14,600,000 BTU/Hr metering at 7 inches WC, 2 psig, and 5 psig. On sets with metering pressures above 5 psig and loads equal to or greater than 14,600,000 BTU/Hr, or loads greater than or equal to 14,600,000 BTU/Hr, electronic pressure correction should be used for better volume correction accuracy.

If a request is made for an elevated pressure above 5 psig and load below 14,600,000 BTU/Hr, gas engineers can use fixed factor correcting heads on rotary meters or electronic correctors on other meters.

Identifying Sites with Special Design and Maintenance Requirements

Certain service points have specialized design and maintenance requirements and should be identified at the time of initial installation by the Customer Project Coordinator or Gas Engineering. For example, commercial or industrial buildings with service lines 2 inches or greater in diameter require an emergency curb valve in Washington (WAC Rule). Additionally, high occupancy structures require an annual leak survey. Reference Specification 2.14, Valve Design for additional site criteria that determines the installation of curb valves (the above sites are not a complete list) as well as Specification 5.11, Leak Survey, for details on the frequency of surveys.

GAS VOLUME CALCULATION:

Behavior of Natural Gas

Natural gas is compressible meaning that a given amount of gas can be expanded or squeezed into different volumes. The pressure of the gas will affect its compressibility. As the pressure of the gas is increased, the gas “squeezes” down and the given amount of gas will occupy a smaller space. As the pressure of the gas is decreased, the gas will expand, and the given amount of gas will occupy a larger space. Therefore, the higher the operating pressure of the gas in the system, the more capacity that system will have.

Temperature also affects the compressibility gas. As the temperature of the gas decreases, the volume of gas will also decrease, and the same amount of gas will then occupy a smaller space. Conversely, as the temperature of the gas increases, the volume of gas increases”, and the same amount of gas will occupy a larger area. Therefore, the higher the temperature of the gas, the less capacity that system will have.

Computing Corrected Flows

Gas meters measure the actual gas volume passing through the meter based on the gas temperature, metering pressure, and elevation. It is necessary to correct the actual measured gas volume to standard metering conditions in order to calculate the SCFH (Standard Cubic Feet per Hour) delivered to the customer. Standard conditions for natural gas are 60 degrees F, 1 atmospheric pressure (14.73 psia), and 0 feet elevation. Elevation corrections are made to at least the closest 100-foot increment. The following calculation will correct gas at non-standard conditions to standard conditions for billing purposes.

Corrected Flow [SCFH] = (Metered Flow)*(Pf+Pe)*(Tf) Where:

Metered Flow = Actual Cubic Feet of Gas per Hour [ACFH]
Pf = Pressure Factor [Corrects metering pressure to standard conditions (14.73 psi)]
Pe = Elevation Factor [Corrects metered volume to zero feet elevation]
Tf = Temperature Factor [Corrects gas temperature to standard conditions (60°F). Tf is only to be used when metering with a non-TC’d meter. Tf = 1 for a TC’d meter]

Elevation Compensation

The factor to compensate for elevation only is simply the atmospheric pressure of the town where the meter is located divided by the base pressure. The factor is as follows:

Elevation Factor $Pe = \frac{Paz}{14.73}$

Where: Pe = Elevation Factor
Paz = Absolute Atmospheric Pressure (psia) at actual location (Refer to Fig. 1)
14.73 = Standard Base Pressure (atmospheric pressure at sea level in psia)

The following table, Fig. 1, shows atmospheric pressures for various elevations within Avista's service territories (rounded to nearest 100-foot increment).

Atmospheric Pressure at Various Elevations Fig. 1

Elevation (ft)	Paz Pressure (psia)	Change / 100 ft.	Elevation (ft.)	Paz Pressure (psia)
0	14.73	.053 / 100 ft.	3600	12.888
100	14.677	.053 / 100 ft.	3700	12.841
200	14.624	.053 / 100 ft.	3800	12.794
300	14.571	.053 / 100 ft.	3900	12.747
400	14.518	.053 / 100 ft.	4000	12.7
500	14.465	.053 / 100 ft.	4100	12.655
600	14.412	.053 / 100 ft.	4200	12.61
700	14.359	.053 / 100 ft.	4300	12.565
800	14.306	.053 / 100 ft.	4400	12.52
900	14.253	.053 / 100 ft.	4500	12.475
1000	14.2	.053 / 100 ft.	4600	12.43
1100	14.147	.053 / 100 ft.	4700	12.385
1200	14.094	.053 / 100 ft.	4800	12.34
1300	14.041	.053 / 100 ft.	4900	12.295
1400	13.988	.053 / 100 ft.	5000	12.25
1500	13.935	.053 / 100 ft.	5100	12.207
1600	13.882	.053 / 100 ft.	5200	12.164
1700	13.829	.053 / 100 ft.	5300	12.121
1800	13.776	.053 / 100 ft.	5400	12.078
1900	13.723	.053 / 100 ft.	5500	12.035
2000	13.67	.053 / 100 ft.	5600	11.992
2100	13.62	0.050 / 100 ft.	5700	11.949
2200	13.57	0.050 / 100 ft.	5800	11.906
2300	13.52	0.050 / 100 ft.	5900	11.863
2400	13.47	0.050 / 100 ft.	6000	11.82
2500	13.42	0.050 / 100 ft.	6100	11.779
2600	13.37	0.050 / 100 ft.	6200	11.738
2700	13.32	0.050 / 100 ft.	6300	11.697
2800	13.27	0.050 / 100 ft.	6400	11.656
2900	13.22	0.050 / 100 ft.	6500	11.615
3000	13.17	0.050 / 100 ft.	6600	11.574
3100	13.123	.047 / 100 ft.	6700	11.533
3200	13.076	.047 / 100 ft.	6800	11.492
3300	13.029	.047 / 100 ft.	6900	11.451
3400	12.982	.047 / 100 ft.	7000	11.41
3500	12.935	.047 / 100 ft.		

Ref. American Meter Company Handbook E-4, 1970 ed.
Displacement Gas Meters, p. 18
(Using 14.73 psia at Sea Level per State Tariffs)

Pressure Compensation

A pressure factor is applied to adjust the volume of measured gas for meters that are measuring gas at a pressure higher than atmospheric conditions. The following formula is used to compute the pressure factor:

$$Pf = \frac{Pg}{14.73}$$

Where: Pf = Pressure factor
Pg = Gauge Pressure (psig)
14.73 = Standard Base Pressure (Absolute atmospheric pressure at Sea Level in psig)

Temperature Compensation

Many of the gas meters used in the system are TC or temperature compensating meters. They are equipped with the mechanics to adjust the flow for temperature variations. Many meters, however, are non-TC meters and may require a temperature factor to be applied to the volume of flow. The following formula is used to compute the factor:

$$Tf = \frac{520}{460 + Tg}$$

Where: Tf = Temperature Factor (For non-TC'd meters). Note: Value equals 1 for a TC'd meter.
520 = Standard Base temperature of 60 degrees Fahrenheit expressed in absolute temperature (degrees Rankine)
460 = 0 degrees Fahrenheit expressed in absolute temperature (degrees Rankine)
Tg = Temperature of the gas stream in degrees Fahrenheit

A non-TC meter is clocked, and the uncorrected flow of gas is found to be 1000 ACFH. Metering pressure is 30 psig, the gas temperature is 45 degrees F, and the meter is located at 1900 feet elevation. What is the corrected flow?

Paz = 13.723 psia (from Figure 1 – Atmospheric Pressure at Various Elevations)
Pg = 30 psig
Tg = 45°F
Therefore: Pf = Pg/14.73 = 30/(14.73) = 2.04
Pe = Paz/14.73 = (13.723/14.73) = 0.93
Tf = 520/(460+Tg) = 520/(460+45) = 1.03
So:
Corrected Flow = (Measured Flow)*(Pf+Pe)*Tf
= (1000)*(2.04+0.93)*(1.03) = 3,059 SCFH

Correction Codes

Once a read is taken from a meter, it must be corrected for elevation, pressure, and/or temperature if necessary and then converted into therms for billing purposes. The billing system completes the conversion of the measured volume at site conditions into a volume at standard conditions. For ease of billing, each method is assigned a Code Number which is used with the appropriate type of meter set and is applied by the computer at the time of billing in the form of a Billing Factor. The various codes are as follows:

METER CORRECTION CODES	
CODE	**DESCRIPTION**
1	A TC meter with a standard index for standard metering pressures of 7 inches WC or 0.25 psig. The billing factor will be calculated by multiplying the BTU content of the gas times the quantity [elevation factor (Pe) + pressure factor (Pf). Billing Factor = (BTU Content)*[(Pf = 0.25/14.73 = 0.017) +Pe]
2	A non-TC meter with a standard index for standard metering pressure of 7 inches WC or 0.25 psig. The billing factor will be calculated by multiplying the BTU of the gas times the quantity [elevation factor (Pe) + pressure factor (Pf)] times the temperature factor (Tf). Billing Factor = (BTU Content)*[(Pf = 0.25/14.73 = 0.017) +Pe)]*Tf
3	A TC meter with a base pressure index (BPI) or an electronic corrector, (usually for metering at pressures higher than 5 psig). The billing factor will be the BTU content of the gas only. Billing Factor = (BTU Content) Note: The billing system does not complete a correction to standard conditions because the field device is providing a meter reading corrected to standard conditions. (Standard Conditions at 60 degrees F, 1 Atmosphere or 14.73 psia)
4	A TC meter with a standard index for metering at 2 psig. The billing factor will be calculated by multiplying the BTU content of the gas times the quantity [elevation factor (Pe) + pressure factor (Pf)]. Billing Factor = (BTU Content)*[(Pf = 2/14.73 = 0.1358)+Pe]
5	A TC meter with a standard index metering at 5 psig. The billing factor will be calculated by multiplying the BTU content of the gas times the quantity [elevation factor (Pe) + pressure factor (Pf)]. Billing Factor = (BTU Content)*[(Pf = 5/14.73 = 0.3394)+Pe]
6	A non-TC meter with a standard index metering at 2 psig. The billing factor will be calculated by multiplying the BTU of the gas times the quantity [elevation factor (Pe) + pressure factor (Pf)] times the temperature factor (Tf) Billing Factor = (BTU Content)*[(Pf = 2/14.73 = 0.1358)+Pe]*(Tf)
7	A non-TC meter with a standard index metering at 5 psig. The billing factor will be calculated by multiplying the BTU of the gas times the quantity [elevation factor (Pe) + pressure factor (Pf)] times the temperature factor (Tf). Billing Factor = (BTU Content)*[(Pf = 5/14.73 = 0.3394)+Pe]*(Tf)
8	A non-TC meter with a standard index metering at 10 psig. The billing factor will be calculated by multiplying the BTU of the gas times the quantity [elevation factor (Pe) + pressure factor (Pf)] times the temperature factor (Tf). Billing Factor = (BTU Content)*[(Pf = 10/14.73 = 0.6789)+Pe]*(Tf)
A	A non-TC meter with a standard index metering at 15 psig. The billing factor will be calculated by multiplying the BTU of the gas times the quantity [elevation factor (Pe) + pressure factor (Pf)] times the temperature factor (Tf) Billing Factor = (BTU Content)*[(Pf = 15/14.73 = 1.0183)+Pe]*(Tf):
P	A TC meter with a pressure compensation index (mechanical or electrical) metering at 10 psig, 15 psig, or 20 psig. The billing factor will be calculated by multiplying the BTU content of the gas times the elevation factor (Pe)Billing Factor = (BTU Content)*(Pe) Note: The billing system does not complete a correction to standard conditions for metering pressure and temperature because the field device is providing a meter reading corrected to standard conditions. (Standard Conditions @ 60 degrees F, 1 Atmosphere or 14.73 psia). Only an elevation correction is required.

NOTES:

1) Customer Bill [Therms] = (Measured Volume [CF])*(Billing Factor)/100,000
2) The billing system uses the following when calculating the quantity of gas measured:
    a. BTU Content – Average calculated BTU content per cubic foot of gas for a given set of dates based on a specific BTU zone.
    b. Tg – Gas Temperature – Average gas temperature for a given set of dates based on a temperature zone.

3) NOTE: A yellow decal on the index and a yellow cap on the spring of the regulator is used to indicate a 2 psig meter set (Code 4 or Code 6). A green decal on the index and a green cap on the spring of the regulator is used to indicate a 5 psig meter set (Code 5 or Code 7). A red decal on the index and a red cap on the spring of the regulator is used to indicate a Code 8, Code A, Code P, or non-standard meter set and tagged with the identifying set pressure. The decal on the index is a redundant indicator in case the regulator spring cap is painted over.

Temperatures Corrected Flows

Gas volumes through meters that are non-temperature compensated must be corrected for the temperature effects on the volume. This is achieved by one of three methods: a temperature-compensating (TC) meter, a correction device installed on the meter such as an electronic corrector (typically for large volume accounts), or by the correcting factor (imbedded in the correction code) applied to the account through the billing system. **Special attention must be paid when setting meters in Oregon to note if they are TC (temperature compensated) or non-TC to apply the proper correction code.**

Frequency of Meter Tests

The periodic testing of gas meters is done in accordance with programs approved by each state and in accordance with Utilities Commission rules. Avista's PMC Program (Gas Meter Measurement Performance Program) uses statistical testing as a quality assurance measure to ensure meters continue to accurately measure flow as the meters age.

Small-capacity meters up to 1000 CFH are grouped into "families" based on the state in which they are installed, the manufacturing date, and the type and make of the meter. For example, American AC250TC meters manufactured in the year 1980 and set in the state of Idaho constitute one family. A statistical sampling of meters to be tested in each family is generated at the beginning of the year. The number of meters to be tested is determined by the size of the family and the past performance of that family. For all other meter sizes, eligible meters are selected based on their type, age, and the last test date. Meters that are eligible for PMC may be pulled either through a dedicated PMC service order or when meter sites are visited for other purposes. The following table lists the requirements by meter type and size.

Meter Type and Size	Test Frequency
Diaphragm, 250-1000 CFH	Statistical sampling
Diaphragm, between 1000 and 3000 CFH	Every 10 years
Diaphragm, 3000 and greater CFH	Every 5 years
Rotary, all sizes	Differential test every 5 years
Turbine, all sizes	Spin test annually and proof tested every 10 years

Prover Calibration Interval

Meter Provers	Calibration Interval
SNAP Prover or Bell Prover	Every Second Calendar Year
Transfer Prover	Every Second Calendar Year

Avista's Requirements for Gas Meter Room Installations

Standard Meter Room(s) Specifications

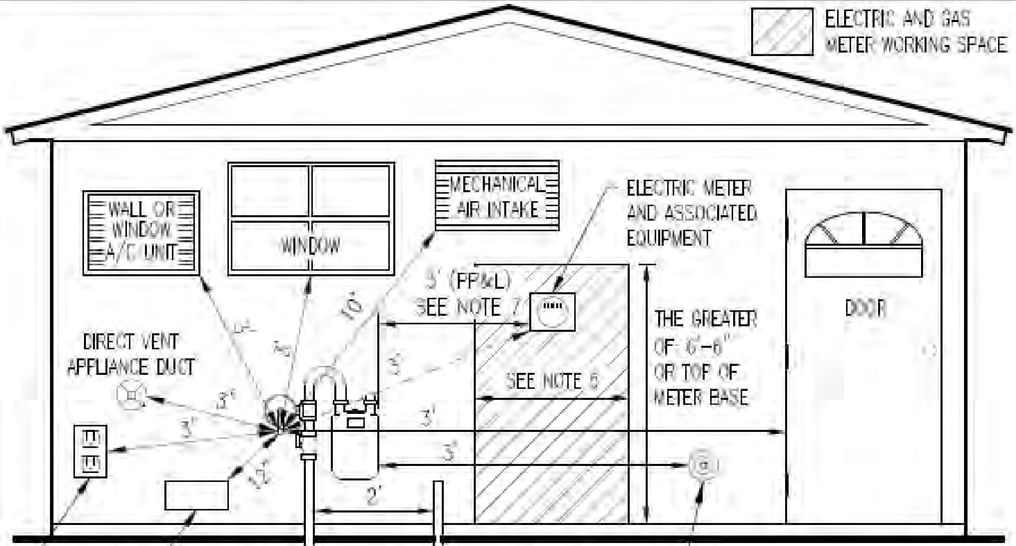
1. Meter room construction must have a minimum 1-hour fire rating, be completely sealed from the rest of the building, and include a self-closing airtight door.
2. Penetration points through the floors, walls, and ceilings of meter room must be vapor-proof sealed and be designed and installed in accordance with applicable regulations, as set forth in federal, state, and municipal codes.
3. It must be equipped with explosion-proof lighting equipment (minimum of one light), that complies with the applicable version of National Electrical Code (NEC), Article 500 and 501 for Hazardous (classified) Locations. Switches located outside the room are not required to be explosion-proof.
4. Meter room must be dedicated to natural gas meter sets only.
5. Meter room must be accessible at all times to Avista. Key box locations are recommended.

Meter Room Ventilation

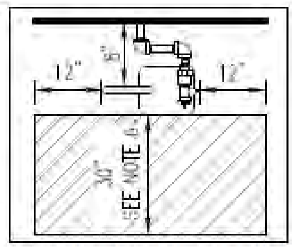
1. Venting configurations must have a minimum of two vents, one at the top and one at the bottom of the meter room. Vents must connect from the meter room to the outside. Specifically:
   - The top vent can be installed either on the ceiling of the meter room or on one of the walls of the meter room, located at a maximum of 1 foot from the top of the vent to the surface of the ceiling.
   - The bottom vent must be installed on one of the walls of the meter room, located a maximum of 1 foot and a minimum of 6 inches from the bottom of the vent to the surface of the floor.
2. Ventilation piping may be installed horizontally through the exterior wall, vertically through the roof, or a combination of the two. The minimum size of the piping is determined by the venting configuration.
   - For vertical vent piping on the top and bottom, and for vertical venting on the top with horizontal venting on the bottom, the minimum vent size is 4 inches.
   - For horizontal venting on the bottom, the minimum vent size is 6 inches.
   - Where little or no vent piping is required, such as a meter room adjacent to an outside wall of the building where the vents are less than 1 foot in length, the minimum vent size is 4 inches. (Square louvers with the same cross-sectional area may also be used.)
3. Vent locations outside should be placed:
   - A minimum of 36 inches from an electric meter or other ignition source.
   - A minimum of 36 inches from a combustion air intake.
   - A minimum of 36 inches from any natural gas appliance direct vent assembly or as specified by the manufacturer of the appliance.
   - A minimum of 10 feet from any mechanical air intake opening.
   - Not under a carport, roof awning, or overhang larger than a standard eave.
     Not under a stairwell or staircase providing the only access or exit to the building (stairwells providing alternative access or exit to the building are an exception to this requirement)

Regulator and Relief Ventilation

Service regulator vents and relief vents must be piped outdoors per "Regulator and Relief Vent Design" in this specification.



ELEVATION



GAS METER PLAN VIEW

1. ELECTRICAL COMPONENTS, DEVICES, & EQUIPMENT INCLUDING SWITCHES, RECEPTACLES, LIGHT FIXTURES, DISCONNECTS, CIRCUIT BREAKERS, PAD MOUNTED AIR CONDITIONERS OR HEAT PUMPS THAT DO NOT SUPPLY VENTILATION AIR, GENERATORS, & TRANSFORMERS SHOULD BE AT LEAST 36" AWAY FROM REGULATOR VENT.
2. DO NOT INSTALL METERS WHERE THEY ARE:
   - SUBJECT TO VEHICULAR OR SNOW DAMAGE, EXCESSIVE CORROSION, OR VIBRATION.
   - DIFFICULT TO READ OR WHERE REGULATOR VENTING IS LIMITED SUCH AS WITHIN A PORCH, DECK, OR ENCLOSURE.
   - IN AN ENGINE, GENERATOR, BOILER, HEATER, OR ELECTRICAL ROOM.
   - LOCATED UNDER OUTSIDE STAIRWAYS OR FIRE ESCAPES.
   - SUSCEPTIBLE TO EXCESSIVE CONDENSATION OR WHERE LIVE STEAM, HOT LIQUID, OR CORROSIVE GASES/VAPORS ARE PRESENT.
   - LOCATED CLOSER THAN 3' FROM OPEN FLAME.
   - IN DRAINAGE AREAS.
3. THE METER SHOULD BE INSTALLED 3' OR LESS FROM WHERE THE HOUSE LINE ENTERS THE STRUCTURE, UNLESS CONDITIONS WARRANT LOCATING THE METER AT A GREATER DISTANCE.
4. ADDITIONAL CLEARANCES & REQUIREMENTS APPLY TO LARGE, HIGH PRESSURE, AND INDUSTRIAL METER SETS.
5. ELECTRIC METER WORKING SPACE SHALL BE THE GREATER OF 30" WIDE OR THE TOTAL WIDTH OF THE ELECTRIC SERVICE AND METERING EQUIPMENT, CENTERED ON THE EQUIPMENT, AND A CLEAR SPACE OF AT LEAST 36" IN FRONT AND PERMIT AT LEAST A 90 DEGREE OPENING OF EQUIPMENT DOORS OR HINGED PANELS. NO BOLLARDS ARE ALLOWED IN THIS SPACE.
6. BOLLARDS OR OTHER TYPES OF METER PROTECTION MAY BE INSTALLED INSIDE THE GAS METER WORKING SPACE AT AVISTA'S DISCRETION.
7. IN PP&L TERRITORY, THE GAS METER ASSEMBLY SHALL BE LOCATED NO CLOSER THAN 3 FEET LATERALLY FROM THE ELECTRIC METER AND ASSOCIATED ENCLOSURE.

NO	DATE	REVISION	BY	CKD
11	9-23-21	STANDARDS UPDATE	CGD	BRS
10	10-10-19	STANDARDS UPDATE	CGD	BRS

DISTRIBUTION - GAS
STANDARD
METER SET
LOCATION GUIDELINES
AVISTA CORP
SPOKANE, WASHINGTON

SCALE	DATE	APPROVED
NONE	11-6-07	11-6-07 (DATE)

DSN. BURGER CKD.
DR. JLW NTD.
CKD. NTD.

SHT 1 OF 1 A-36275

AUTOCAD DWG

9/23/2021 9:35 AM

2.23 REGULATOR DESIGN

SCOPE:

To establish a uniform procedure for designing gas farm tap style regulator stations, larger district regulator stations, and service regulators.

REGULATORY REQUIREMENTS:

§192.181, §192.195, §192.197, §192.199; §192.201, §192.203, §192.353, §192.355, §192.357, §192.359, §192.741

WAC 480-93-020, 480-93-130, 480-93-140

OAR 860-023-0035

CORRESPONDING STANDARDS:

Spec. 2.14, Valve Design
Spec. 2.22, Meter Design
Spec. 2.24, Meter & Regulator Tables & Drawings
Spec. 3.16, Services
Spec. 5.12, Regulator and Relief Inspection

DESIGN REQUIREMENTS:

General

Each regulating system reducing gas pressure must have overpressure protection such as a monitor regulator, relief valve, or shut-off valve. When a relief valve is used it must be sized for a wide-open failure of the largest capacity regulator.

Regulating systems acting as either District Regulators or Single Service Farm Taps shall be designed to prevent any single incident from causing an overpressurization of the downstream system, including multi-stage pressure regulation.

Regulating system equipment including monitor regulators and shut-off devices must be designed to handle the MAOP of the system upstream of the regulating system.

Service regulators shall utilize a method of overpressure protection to ensure pressure build-up under no flow conditions does not cause unsafe operation of any connected and properly adjusted gas utilization equipment.

Overpressure devices must be designed to meet the requirements of §192.199 by:

1. Being constructed of materials such that the operation of a device will not be impaired by corrosion;
2. Have valves and valve seats that are designed not to stick in a position that will make the device inoperative;
3. Be designed and installed so that it can be readily operated to determine if the valve is free, can be tested to determine the pressure at which it will operate and can be tested for leakage when in the closed position;

4. Have supports made of noncombustible material;
5. Have discharge stacks, vents, or outlet ports designed to prevent accumulation of water, ice, or snow, and located where gas can be discharged into the atmosphere without undue hazard;
6. Be designed and installed so that the size of the openings, pipe, and fittings located between the system to be protected and the pressure relieving device, and the size of the vent line are adequate to prevent hammering of the valve and to prevent impairment of relief capacity;
7. Where installed at a district regulator station to protect a pipeline system from over-pressuring, be designed and installed to prevent any single incident such as an explosion in a vault or damage by a vehicle from affecting the operation of both the overpressure protective device and the district regulator; and
8. Except for a valve that will isolate the system under protection from its source of pressure, be designed to prevent unauthorized operation of any stop valve that will make the pressure relief valve or pressure limiting device inoperative.

Sizing Requirements

Regulating systems should be sized to maintain the required station outlet pressure under full load conditions with the station inlet pressure at a minimum expected value. Other factors to consider include the pressure drop in the inlet and outlet piping, fittings, and valves within the station flow path.

Overpressure devices shall be sized to control the wide-open capacity of the regulator without exceeding the downstream MAOP. They shall be designed and installed so that the size of the openings, pipes, valves, and fittings located between the system to be protected and the pressure-relieving device and the size of the vent line downstream are adequate to prevent hammering of the relief valve and to prevent restriction of relief capacity.

Regulation of Intermediate Pressure to Service Pressure

If the MAOP of the distribution system is 60 psig or less, a suitable protective device such as an internal relief valve on the service regulator, a monitor regulator, an independent relief valve, or an automatic shut-off valve shall be used to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

Regulation of High Pressure to Service Pressure

If the MAOP of the distribution or transmission system exceeds 60 psig, one of the following methods must be used to regulate and limit, to the maximum safe value, the pressure of gas delivered to the customer:

1. Two stage pressure reduction consisting of an upstream regulator performing a first stage pressure cut followed by a service regulator. The upstream regulator may not be set to maintain a pressure higher than 60 psig. A device must be installed between the upstream regulator and the service regulator to limit the pressure on the inlet of the service regulator to 60 psig or less in case the upstream regulator fails to function properly. This device may be either a relief valve or an automatic shutoff valve that closes if the pressure on the inlet of the service regulator exceeds the set pressure (60 psig or less) and remains closed until manually reset. The service regulator must also feature a suitable protective device such as an internal relief valve, a monitor regulator, an independent relief valve, or a shut-off valve to protect the customer’s piping downstream of the meter to a maximum safe level in the event the service regulator malfunctions.
2. A service regulator and a monitoring regulator set to limit, to a maximum safe value, the pressure of the gas delivered to the customer.

3. A service regulator with a relief valve vented to the outside atmosphere, with the relief valve set to open so that the pressure delivered to the customer does not exceed a maximum safe value. The relief valve may either be built into the service regulator, or it may be a separate unit installed downstream from the service regulator. This combination may be used alone only in those cases where the inlet pressure on the service regulator does not exceed the manufacturer's safe working pressure rating of the service regulator, and may not be used where the inlet pressure on the service regulator exceeds 125 psig. For higher inlet pressures, refer to (1) and (2) in this section.
4. A service regulator and an automatic shutoff device that closes upon a rise in pressure downstream from the regulator and remains closed until manually reset.

WAC 480-93-020: In the state of Washington, proximity consideration is required for buildings of human occupancy within 500 feet of a gas facility having a minimum operating pressure greater than 500 psig and also within 100 feet of a gas facility having a minimum operating pressure between 250 psig and 500 psig. Refer to Specification 2.12, Pipe Design - Steel for specific requirements.

Valves

Each regulator station must have a valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station (50 feet preferred, 20 feet minimum). Refer to Specification 2.14, Valve Design. Consideration should be given to locating a valve downstream of the station especially if the system is back fed to enable isolation of the station from both directions.

Except for a valve that will isolate the regulating system from its source of pressure, handles from other valves in the station should be locked or removed to prevent unauthorized operation.

Control and Sensing Lines

Each takeoff connection and attaching fitting or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue.

Control and sensing lines should be located at a point of non-turbulent laminar flow. This generally is achieved by placing sensing taps a minimum of 10 pipe diameters (based on regulator size) downstream of valves, regulators, or fittings.

Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one-control line from making both the regulator and the overpressure protection device inoperative. Each sensing line shall have an individual tap.

A shutoff valve must be installed in each takeoff line as near as practical to the point of takeoff. Blow down valves must be installed where necessary.

Strainers and/or filters should be installed as needed to prevent clogging of lines or orifices by foreign materials.

Capacity

Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity and must be set to operate as follows:

1. In a low-pressure distribution system (less than 1 psig), the pressure may not cause the unsafe operation of any connected and properly adjusted gas utilization equipment.

2. In other pipeline systems, if:

    a. The MAOP is greater than or equal to 60 psig the pressure may not exceed the MAOP plus 10 percent or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower.

    b. The MAOP is greater than or equal to 12 psig or more, but less than 60 psig, the pressure may not exceed the MAOP plus 6 psig.

    c. The MAOP is less than 12 psig; the pressure may not exceed the MAOP plus 50 percent.

In regulator stations with relief devices, the relief set points may not exceed those specified by Gas Engineering. These calculations must include allowances for any pressure build-up due to pipe, fittings, and valves in the station, as well as for any outlet pressure limitations on the regulators. Relief capacity calculations and determination of relief set points should not be performed by field personnel.

Telemetering and Pressure Recorders

In general, telemetering should be provided to monitor system flows and pressures from areas of special interest such as gate stations and at meter sets of large industrial customers.

Each distribution system supplied by more than one district regulator station shall be equipped with telemetering or recording pressure gauges to indicate the gas pressure in the district.

On distribution systems supplied by a single district regulator station, Gas Engineering shall determine the necessity of installing telemetering or recording gauges in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.

Reference Specification 2.25, Telemetry Design for detail regarding the design and installation of telemetry devices.

Regulator Station Numbering

Regulator station numbering shall be generated by Gas Engineering and verified through the Avista Gas Design Tool. Renumbering is not necessary or recommended for a station that is being rebuilt. Consideration should be given to renumbering the station if it is moved for any reason to a new location more than 100 feet from the former location.

2.24 METER AND REGULATOR TABLES AND DRAWINGS

The following tables and drawings are to be used in aiding the sizing and design of gas metering and regulating facilities. The tables are not included as standards, but as guidelines and tools. The drawings are the standard for new installations and should be used as guidelines when bringing meters up to standard.

In the interest of saving space within the following tables, the unit PSI is understood to mean PSIG and the unit CFH is understood to mean SCFH. Only regulators that are currently being installed are shown in the following tables. Contact Gas Engineering or the Gas Meter Shop if there are questions regarding regulators that are not included in the tables.

The following table summarizes how the capacity of each regulator was determined based on the manufacturer's literature.

Regulator		Accuracy of Set Pressure		
Make	**Type**	**7" WC**	**2 PSIG**	**5 PSIG**
American	1813B	+2"/-1" WC	± 2% Absolute	± 2% Absolute
American	1813C	+2"/-1" WC	± 10% Gauge	N/A
Fisher	CS800	+2"/-1" WC	N/A	N/A
Fisher	CS820	N/A	± 2% Absolute	± 2% Absolute
Fisher	HSR	+2"/-1" WC	± 1% Absolute	N/A
Fisher	299H	+2"/-1" WC	± 1% Absolute	± 1% Absolute
Itron	B42	+2"/-1" WC	± 1% Absolute	N/A
Itron	CL-31-IMRV	N/A	± 1% Absolute	± 1% Absolute
Itron	CL-38-2IM	N/A	± 1% Absolute	± 1% Absolute
Sensus	143-80	+2"/-1" WC	± 10% Gauge	± 10% Gauge

Relief Capacity

Relief capacities should be calculated to protect the downstream system as follows:

Delivery Pressure	Protect downstream system to no more than
7" WC	2 PSIG
2 PSIG	5 PSIG
5 PSIG	10 PSIG

Obsolete Regulators

The following regulators are obsolete and shall no longer be utilized within the gas distribution system. When identified, these regulators shall be replaced or scheduled to be changed out as soon as arrangements can be made for access to the customer's equipment.

OBSOLETE REGULATORS

Regulator	Issue
American Reliance Type K	No relief valve.
American Reliance 1400, 1401, 1402, 1403	No relief valve.
American Reliance 1410, 1411, 1412, 1413	Insufficient data on relief valve performance.
Fisher S100	No relief valve.
Fisher S102	Inadequate relief valve for 3/16” or larger orifice. Relief valve OK for 1/8” orifice.
Fisher 730C, 733C	Inadequate relief valve / inconsistent lockup.
Fisher 810, 8100	Inadequate or no relief valve.
Fisher S252, S254 with 3/16” or larger orifice.	Inadequate relief valve for 3/16” or larger orifice. Relief valve OK for 1/8” orifice.
Fisher S253	No relief valve.
Fisher S292-4	Inadequate or no relief valve.
Rockwell 043-90, 043-91, 043-180, 043-181	No relief valve.
Rockwell 043-92, 043-182 with 3/16” or larger orifice.	Inadequate relief valve for 3/16” or larger orifice. Relief valve OK for 1/8” orifice.
Rockwell 107	Undocumented relief valve performance.
Rockwell 143-1, 143-4	No relief valve.
Rockwell 143-2, 143-6 with 1/4” or larger orifice.	Inadequate relief valve for 1/4” or larger orifice. Relief valve OK for 1/8” and 3/16” orifice.
Rockwell 143-80-1,143-80-4	No relief valve.
Rockwell 143-80-2 with 1/4” or larger orifice.	Inadequate relief valve for 1/4” or larger orifice. Relief valve OK for 1/8” and 3/16” orifice.
Rockwell 173	Undocumented relief valve performance.

METER CAPACITY TABLES - DIAPHRAGM METERS

PRESSURE RATING	CLASS	METER		CAPACITY IN CFH AT METER PRESSURE SHOWN							
		Size	Make	7" WC	2 PSI	5 PSI	10 PSI	15 PSI	20 PSI	35 PSI	50 PSI
5 psi	A	AC250	American	300	600	n/a	n/a	n/a	n/a	n/a	n/a
5 psi	A	R275	Sensus*	300	600	n/a	n/a	n/a	n/a	n/a	n/a
10 psi	B	AL425	American	525	950	1025	n/a	n/a	n/a	n/a	n/a
25 psi	B	AC630	American	800	1375	1500	1700	1875	n/a	n/a	n/a
20 psi**	B	AL800	American	1025	1775	2100	2600	2800	3200	4200	5100
25 psi**	B	AL1000	American	1275	2275	2700	3400	3700	4100	5550	6600
100 psi	C	AL1400	American	1800	3125	3700	4600	5000	5600	7550	9000
100 psi	C	AL2300	American	2950	5250	6200	7700	8400	9400	12675	15000
100 psi	C	AL5000	American	6450	11400	13500	17000	18500	20600	27700	33000

*Formerly Rockwell/Equimeter
**Also Available in Case Rated at 100 psi

7-inch WC capacity based on 0.75 inch WC differential across the meter (based on manufacturer’s recommendation). 2 PSIG and greater capacities are based on a 2-inch WC differential across the meter.

Grayed out meters may be found in the field but are not currently installed as new

ROTARY METERS

METER SIZE	CAPACITY IN CFH AT METER PRESSURE SHOWN							
	7" WC	2 PSI	5 PSI	10 PSI	15 PSI	20 PSI	35 PSI	50 PSI
8C	800 *	900	1050	1300	1600	1900	2600	3500
1.5M	1500 *	1700	2000	2500	3000	3500	5000	6600
2M	2000 *	2200	2600	3300	4000	4700	6700	8700
3M	3000 *	3300	4000	5000	6000	7000	10000	13100
3.5M	3500 *	3900	4600	5800	7000	8200	11700	15300
5M	5000 *	5600	6600	8300	10000	11700	16800	21900
5.5M	5500 *	6125	7225	9100	11000	12850	18400	24000
7M	7000	7800	9300	11700	14100	16400	23500	30700
11M	11000	12300	14600	18300	22100	25800	37000	48200
16M	16000	17800	21100	26500	31900	37400	53600	70000
23M	23000	25600	30300	38100	45900	53700	77100	100600

* A diaphragm meter should be used instead of a rotary meter for this application.
If limited space will not allow the installation of a diaphragm meter, then a rotary meter may be used.

ROTARY METER MANUFACTURER	PRESSURE RATING (PSIG)
Schlumberger/Actaris	125
Romet	175
Roots (Cast Iron Models 11M, 16M, 23M)	125
Roots/Dresser (except 23M232)	175 (8C-5M also available in 200 PSIG)
Dresser 23M232	232
American	275

TURBINE METERS

PRESSURE RATING *	METER		CAPACITY IN CFH AT METER PRESSURE SHOWN WITH 45 DEGREE ROTORS (STANDARD)							
	SIZE	MAKE	2 PSI	5 PSI	10 PSI	15 PSI	20 PSI	35 PSI	50 PSI	100 PSI
275 psi	3GT	American	11,000	13,000	16,000	20,000	23,000	33,000	44,000	78,000
175 psi	4GT	American	20,000	24,000	30,000	36,000	42,000	60,000	79,000	140,000
125 psi	4TURBO	Sensus **	20,000	24,000	30,000	36,000	42,000	60,000	79,000	142,000
175 psi	6GT	American	33,000	40,000	50,000	60,000	70,000	100,000	131,000	233,000
125 psi	6TURBO	Sensus **	39,000	46,000	58,000	70,000	82,000	116,000	154,000	276,000
125 psi	8TURBO	Sensus **	67,000	79,000	100,000	120,000	141,000	203,000	265,000	474,000
220 psi	12TURBO	Sensus **	156,000	185,000	233,000	281,000	329,000	473,000	618,000	1,106,000

PRESSURE RATING *	METER		CAPACITY IN CFH AT METER PRESSURE SHOWN WITH 30 DEGREE ROTORS (OPTIONAL)							
	SIZE	MAKE	2 PSI	5 PSI	10 PSI	15 PSI	20 PSI	35 PSI	50 PSI	100 PSI
275 psi	3GT	American	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
175 psi	4GT	American	25,400	30,000	38,000	46,000	54,000	77,500	101,000	181,000
125 psi	4TURBO	Sensus **	30,500	36,000	45,000	54,000	63,000	90,800	119,000	213,000
175 psi	6GT	American	55,900	66,000	83,000	100,000	117,000	167,000	134,000	394,000
125 psi	6TURBO	Sensus **	64,000	75,000	95,000	114,000	134,000	190,000	252,000	450,000
125 psi	8TURBO	Sensus **	101,000	119,000	150,000	181,000	211,000	300,000	397,000	711,000
220 psi	12TURBO	Sensus **	257,000	304,000	383,000	461,000	540,000	767,000	1,015,000	1,816,000

* Available with higher pressure ratings
** Formerly Rockwell/Equimeter

Grayed out meters may be found in the field but are not currently installed as new.

REGULATOR CAPACITY TABLES

REGULATOR CLASSIFICATIONS:
CLASS A = RESIDENTIAL 7 –inch W.C. - 0 to 500 CFH
CLASS B = RESIDENTIAL 2 PSIG, & SMALL COMMERCIAL 7 -inch W.C. & 2 PSIG - 500 to 2,000 CFH
CLASS C = LARGE COMMERCIAL 7 -inch W.C. & 2 PSIG - 2,000 to 10,000 CFH
CLASS D = LARGE COMMERCIAL 2PSIG & 5 PSIG - 10,000 to 30,000 CFH

METER SET REGULATORS (BASED ON 30 PSIG INLET; 46-60 PSIG MAOP)

Class	Make	Type	Body Size Configuration	Orifice	7" W.C. Capacity CFH	2 PSIG Capacity CFH	5 PSIG Capacity CFH
A&B	SENSUS	143-80	3/4"X1"	1/8"	695	695	695
	INVENSYS		180 DEG	3/16"	1,465	1,465*	1,465*
	EQUIMETER			1/4"	2,000*	2,000*	2,000*
	ROCKWELL			5/16"	**	**	**
	WA/ID ONLY			3/8"	**	**	**
				1/2"	**	**	**
B	AMERICAN	1813 C	3/4"X1"	1/8"	600	650	n/a
			90 & 180 DEG	3/16"	1,400	1,300	n/a
				1/4"	2,300*	1,700[1]	n/a
				5/16"	****	****	n/a
				3/8"	****	****	n/a
				1/2"	**	**	n/a
B	AMERICAN	1813 C	1-1/4"x1-1/4"	1/8"	700	650	n/a
	OREGON ONLY		90 & 180 DEG	3/16"	1,600***	1,500	n/a
				1/4"	****	2,500[1]	n/a
				5/16"	****	****	n/a
				3/8"	****	****	n/a
B	ITRON	B42	3/4"x1"	1/8"	700	500	n/a
	ACTARIS		90 & 180 DEG	1/8"x3/16"	700	700	n/a
	SCHLUMBERGER			3/16"	1,400	900	n/a
	WA/ID ONLY			1/4"	2,000*	1,230*	n/a
				5/16"	**	**	n/a

Class	Make	Type	Body Size Configuration	Orifice	7" W.C. Capacity CFH	2 PSIG Capacity CFH	5 PSIG Capacity CFH
A&B	FISHER	HSR	3/4"x1"	1/8"	710	650	n/a
			90 & 180 DEG	3/16"	1,480	1,150	n/a
				1/4"	Pending[4]	1,780*	n/a
				3/8"	**	**	n/a
				1/2"	**	**	n/a
B&C	ITRON	CL-31-IMRV	3/4"x1"	1/8"	n/a	700[2]	700[2]
	ACTARIS		& 1-1/4"x1-1/4"	3/16"	n/a	1,575[2]	1,575[2]
	SCHLUMBERGER		180 DEG	1/4"	n/a	2,275[2]	2,250[2]
				5/16"	n/a	2,700[2]	2,700[2]
C	AMERICAN	1813 B	2"x2"	1/4"	2,800	2,600	1,500
	OREGON ONLY		180 DEG	3/8"	5,900	5,700	2,000
				1/2"	10,300*	10,100[1]	3,200
				5/8"	****	12,600*	3,900*
				3/4"	****	15,900*	4,700*
				7/8"	****	18,000*	4,600*
C	FISHER	CS800IQ (in)	2"X2"	3/8"x1/4"	2850	2,940	2,930
		CS820IQ (lbs)	180 DEG	3/8"	6290	6,170	4,050
				1/2"	11,850[1]	11,770	6,360
		High Capacity		5/8"	18,720*	16,960*	8,380
		2-1/2" IRV		3/4"	23,010*	20,850*	10,580
				7/8"	**	23,130*	13,250*
				1"	**	**	**
C&D	FISHER	299H	2"x2"	1/4"x3/8"	2,890*	2,890*	2,890*
	WA/ID ONLY	**NO IRV**	180 DEG	3/8"	6,640*	6,640*	6,640*
				1/2"	11,540*	11,540*	11,540*
				3/4"	24,800*	24,800*	24,800*
				1"	40,950*	40,950*	40,950*
				1-3/16"	51,040*	51,040*	51,040*
C&D	ITRON	CL-38-2IMRV	2"x2"	3/8"	n/a	6,000[3]	6,000[3]
	ACTARIS		180 DEG	1/2"	n/a	8,900[3]	8,900[3]
	SCHLUMBERGER			5/8"	n/a	13,600[3]	13,600[3]
				3/4"	n/a	15,800[3]	15,800[3]
			Use Black Closing Spring→	1”	n/a	19,400[3]	19,400[3]

* Exceeds IRV capacity, or has no IRV. Assemble with properly sized relief valve.

** Exceeds maximum inlet rating for orifice size, replace with proper regulator or orifice if found in the field.

*** Acceptable if found in the field. Do not install new in this configuration.

**** Not acceptable because of IRV capacity and parameters fall outside of optimum performance criteria, replace with proper regulator or orifice if found in the field.

[1] Internal Relief Valve OK at typical high operating pressure of 2-4 psig below MAOP.

[2] When using a CL31-IMRV regulator, a 1-inch Fisher 289H relief valve should also be installed. If the regulator is set at 2 psig, set the relief valve at 4 psig. If the regulator is set at 5 psig, set the relief valve at 8 psig.

[3] When using a CL38-2IMRV regulator, a 2-inch Fisher 289H relief valve should also be installed. If the regulator is set at 2 psig, set the relief valve at 4 psig. If the regulator is set at 5 psig, set the relief valve at 8 psig.

[4] Capacity at 7” w.c. is not currently published by the manufacturer for this orifice size. Capacity will be updated once this information is available from the manufacturer.

METER SET REGULATORS (BASED ON 15 PSIG INLET; 22.6-45 PSIG MAOP)

Class	Make	Type	Body Size Configuration	Orifice	7" W.C. Capacity CFH	2 PSIG Capacity CFH	5 PSIG Capacity CFH
A&B	SENSUS INVENSYS EQUIMETER ROCKWELL WA/ID ONLY	143-80	3/4"X1" 180 DEG	1/8"	450	450	450
				3/16"	1,035	1,035	1,035
				1/4"	1,680	1,680*	1,680*
				5/16"	**	**	**
				3/8"	**	**	**
				1/2"	**	**	**
				5/8"	**	**	**
B	AMERICAN	1813 C	3/4"X1" 90 & 180 DEG	1/8"	425	425	n/a
				3/16"	900	800	n/a
				1/4"	1,400	1,000	n/a
				5/16"	****	****	n/a
				3/8"	****	****	n/a
B	AMERICAN OREGON ONLY	1813 C	1-1/4"x1-1/4" 90 & 180 DEG	1/8"	450	425	n/a
				3/16"	1,000***	850	n/a
				1/4"	1,800***	1,200	n/a
				5/16"	****	**	n/a
				3/8"	****	**	n/a
B	ITRON ACTARIS SCHLUMBERGER WA/ID ONLY	B42	3/4"x1" 90 & 180 DEG	1/8"	425	300	n/a
				1/8"x3/16"	470	415	n/a
				3/16"	850	500	n/a
				1/4"	1,200[1]	650*	n/a
				5/16"	**	**	n/a
				3/8"	**	**	n/a
A&B	FISHER	HSR	3/4"x1" 90 & 180 DEG	1/8"	423	380	n/a
				3/16"	840	620	n/a
				1/4"	1,475*	950*	n/a
				3/8"	**	**	n/a
				1/2"	**	**	n/a
B&C	ITRON ACTARIS SCHLUMBERGER	CL-31-IMRV	3/4"x1" & 1-1/4"x1-1/4" 180 DEG	1/8"	n/a	500[2]	500[2]
				3/16"	n/a	1,025[2]	950[2]
				1/4"	n/a	1,375[2]	1,275[2]
				5/16"	n/a	1,650[2]	1,525[2]
C	AMERICAN OREGON ONLY	1813 B	2"x2" 180 DEG	1/4"	1,900	1,800	1,000
				3/8"	4,000	3,200	1,100
				1/2"	6,400*	5,500	1,900
				5/8"	****	6,200*	2,300
				3/4"	****	8,500*	2,600
				7/8"	****	9,600*	2,600*
C	FISHER	CS800IQ (in) CS820IQ (lbs) High Capacity 2-1/2" IRV	2"X2" 180 DEG	3/8" x 1/4"	1,870	1,980	1,820
				3/8"	3,130	4,150	1,950
				1/2"	7,760	7,440	3,410
				5/8"	12,000*	10,230	4,020
				3/4"	16,170*	12,410*	5,440
				7/8"	****	15,290*	5,830
				1"	**	**	**

Class	Make	Type	Body Size Configuration	Orifice	7" W.C. Capacity CFH	2 PSIG Capacity CFH	5 PSIG Capacity CFH
C&D	FISHER WA/ID ONLY	299H **NO IRV**	2"x2" 180 DEG	1/4"x3/8"	1,920*	1,920*	1,870*
				3/8"	4,410*	4,360*	4,190*
				1/2"	7,670*	7,580*	7,280*
				3/4"	16,480*	15,990*	15,150*
				1"	25,750*	25,050*	23,310*
				1-3/16"	31,690*	30,760*	28,530*
C&D	ITRON	CL-38-2IMRV	2"x2"	3/8"	n/a	3,950[3]	3,750[3]
	ACTARIS		180 DEG	1/2"	n/a	5,450[3]	5,200[3]
	SCHLUMBERGER			5/8"	n/a	9,000[3]	8,600[3]
				3/4"	n/a	10,400[3]	10,000[3]
		Use Black Closing Spring→		1"	n/a	12,800[3]	12,200[3]

* Exceeds IRV capacity, or has no IRV. Assemble with properly sized relief valve.

** Exceeds maximum inlet rating for orifice size, replace with proper regulator or orifice if found in the field.

*** Acceptable if found in the field. Do not install new in this configuration.

**** Not acceptable because of IRV capacity and parameters fall outside of optimum performance criteria, replace with proper regulator or orifice if found in the field.

[1] Internal Relief Valve OK at typical high operating pressure of 2-4 psig below MAOP.
[2] When using a CL31-IMRV regulator, a 1-inch Fisher 289H relief valve should also be installed. If the regulator is set at 2 psig, set the relief valve at 4 psig. If the regulator is set at 5 psig, set the relief valve at 8 psig.
[3] When using a CL38-2IMRV regulator, a 2-inch Fisher 289H relief valve should also be installed. If the regulator is set at 2 psig, set the relief valve at 4 psig. If the regulator is set at 5 psig, set the relief valve at 8 psig.

METER SET REGULATORS (BASED ON 5 PSIG INLET; 10-22.5 PSIG MAOP)

Class	Make	Type	Body Size Configuration	Orifice	7" W.C. Capacity CFH	2 PSIG Capacity CFH
B	AMERICAN OREGON ONLY	1813 B	2"x2" 180 DEG	1/4"	1,000	850
				3/8"	2,000	1,600
				1/2"	2,900	2,300
				5/8"	4,000*	2,600
				3/4"	5,000*	3,700
				7/8"	7,000*	4,100*
				1"	****	4,400*
B	AMERICAN	1813 C	3/4"X1" 90 & 180 DEG	1/8"	250	225
				3/16"	450	350
				1/4"	650	450
				5/16"	750	500
				3/8"	950*	650
				1/2"	1,200*	750*
				9/16"	**	**
B	AMERICAN OREGON ONLY	1813 C	1-1/4" x 1-1/4" 90 & 180 DEG	1/8"	275	225
				3/16"	550	350
				1/4"	1,000	500
				5/16"	1,600	600
				3/8"	2,100*	700[1]
				1/2"	2,500*	900*

Class	Make	Type	Body Size Configuration	Orifice	7" W.C. Capacity CFH	2 PSIG Capacity CFH
A&B	FISHER	HSR	3/4"x1" 90 & 180 DEG	1/8" 3/16" 1/4" 3/8" 1/2"	228 338 575 938* **	***** 250 350 510* **
B&C	ITRON ACTARIS SCHLUMBERGER	CL-31-IMRV	3/4"x1" & 1-1/4"x1-1/4" 180 DEG	1/8" 3/16" 1/4" 5/16"	n/a n/a n/a n/a	275[2] 500[2] 600[2] 680[2]
C	FISHER	CS800IQ (in) CS820IQ (lbs) High Capacity 2-1/2" IRV	2"X2" 180 DEG	3/8" x 1/4" 3/8" 1/2" 5/8" 3/4" 7/8" 1" 1-3/8"	1,120 1,120 2,600 3,670 4,630* 8,130* 9,590* **	1,140 1,850 3,140 4,120 5,150 6,120 7,050* **
C&D	ITRON ACTARIS SCHLUMBERGER	CL-38-2IM	2"x2" 180 DEG	3/8" 1/2" 5/8" 3/4" 1"	n/a n/a n/a n/a n/a	1,900[3] 2,650[3] 4,250[3] 4,950[3] 6,250[3]

* Exceeds IRV capacity, or has no IRV. Assemble with properly sized relief valve.
** Exceeds maximum inlet rating for orifice size, replace with proper regulator or orifice if found in the field.
*** Acceptable if found in the field. Do not install new in this configuration.
**** Not acceptable because of IRV capacity and parameters fall outside of optimum performance criteria, replace with proper regulator or orifice if found in the field.

***** Not acceptable because droop/boost would exceed design criteria. Replace with proper regulator or orifice if found in the field.

[1] Internal Relief Valve OK at typical high operating pressure of 2-4 psig below MAOP.
[2]When using a CL31-IMRV regulator, a 1-inch Fisher 289H relief valve should also be installed. If the regulator is set at 2 psig, set the relief valve at 4 psig.
[3]When using a CL38-2IMRV regulator, a 2-inch Fisher 289H relief valve should also be installed. If the regulator is set at 2 psig, set the relief valve at 4 psig.

METER SET REGULATORS (BASED ON 2 PSIG INLET; 6-8 PSIG MAOP)

Class	Make	Type	Body Size Configuration	Orifice	7" W.C. Capacity CFH	2 PSIG[(1)] Capacity CFH
B	AMERICAN OREGON ONLY	1813 B	2"x2" 180 DEG	1/4" 3/8" 1/2" 5/8" 3/4" 7/8" 1"	n/a 1,250 1,600 2,400 2,700 3,500 4,400*	575[2] 1,100[2] 1,600[2] 1,700[2] 2,200[2] 2,500[2] 2,800[2]

Class	Make	Type	Body Size Configuration	Orifice	7" W.C. Capacity CFH	2 PSIG[(1)] Capacity CFH
B	AMERICAN	1813 C	3/4"X1" 90 & 180 DEG	1/8"x3/16"	n/a	150
				3/16"	250	225
				1/4"	350	250
				5/16"	450	350
				3/8"	500	425
				1/2"	600*	550
				9/16"	650*	550*
B	AMERICAN OREGON ONLY	1813 C	1-1/4" x 1-1/4" 90 & 180 DEG	1/8"x3/16	n/a	150
				3/16"	325	225
				1/4"	500	350
				5/16"	600	375
				3/8"	700	425
				1/2"	950*	550
				9/16"	1,400*	550*
A&B	FISHER	HSR	3/4"x1" 90 & 180 DEG	1/8"	148	*****
				3/16"	220	*****
				1/4"	283	200
				3/8"	418	300
				1/2"	623*	400
B&C	ITRON ACTARIS SCHLUMBERGER	CL-31-IMRV	3/4"x1" & 1-1/4"x1-1/4" 180 DEG	1/8"	n/a	n/a
				3/16"	n/a	300[3]
				1/4"	n/a	325[3]
				5/16"	n/a	350[3]
C	FISHER	CS800IQ (in) CS820IQ (lbs) High Capacity 2-1/2" IRV	2"X2" 180 DEG	3/8" x 1/4"	810	720
				3/8"	1,080	1,150
				1/2"	2,040	1,980
				5/8"	2,750	2,470
				3/4"	3,950	3,230
				7/8"	4,610	3,540
				1"	4,990	4,200
				1-3/8"	6,250*	5,640
C&D	ITRON ACTARIS SCHLUMBERGER	CL-38-2IM	2"x2" 180 DEG	3/8"	1,400[4]	1,150[4]
				1/2"	1,950[4]	1,600[4]
				5/8"	3,100[4]	2,550[4]
				3/4"	3,650[4]	3,000[4]
				1"	4,550[5]	3,750[4]

* Exceeds IRV capacity, or has no IRV. Assemble with properly sized relief valve.

***** Not acceptable because droop/boost would exceed design criteria. Replace with proper regulator or orifice if found in the field.[1] Capacities at 2 psig delivery pressure are sized using a 3 psig inlet pressure.
[2] Use American Meter spring 71424P021 (1-2 psig) to achieve listed capacity.
[3] When using a CL31-IMRV regulator, a 1-inch Fisher 289H relief valve should also be installed. If the regulator is set at 2 psig, set the relief valve at 4 psig.
[4] When using a CL38-2IMRV regulator, a 1-inch Fisher 289H relief valve should also be installed. If the regulator is set at 7" WC, set the relief valve at 1 psig. If the regulator is set at 2 psig, set the relief valve at 4 psig.
[5] When using a CL38-2IMRV regulator with a 1 inch orifice at 7-inch WC, a 2-inch Fisher 289H relief valve set at 1 psig should also be installed.

FARM TAP REGULATOR 500 PSIG MAOP INLET (50 PSIG SET POINT)

Class	Make	Type	Body Size Configuration	Orifice	150 PSIG Inlet Capacity CFH	250 PSIG Inlet Capacity CFH	500 PSIG Inlet Capacity CFH
N/A	Fisher	620 & 621 OUT OF PRODUCTION	3/4"x3/4"	3/32"	1,360*	2,190*	4,200*
				1/8"	2,430*	3,910*	7,500*
				1/4"	9,070*	15,000*	28,650*
				3/8"	N/A**	N/A**	N/A**
				1/2"	N/A**	N/A**	N/A**
N/A	Fisher	627R* IRV INADEQUATE	3/4"x3/4"	3/32"	1,420*	2,275*	4,400*
				1/8"	2,580*	4,100*	8090*
				3/16"	5,850*	9,400*	18,300*
				1/4"	9,740*	15,050*	20,000*
				3/8"	**	**	N/A**
				1/2"	**	**	N/A**
N/A	Fisher	630*	2" x2"	1/8"	2,600*	4,550*	9,500*
				3/16"	5,700*	9,450*	20,500*
				1/4"	8,700*	15,500*	37,500*
				3/8"	13,000*	34,500*	86,500*
				1/2"	N/A**	N/A**	N/A**
N/A	Rockwell (Equimeter)	O41* OUT OF PRODUCTION	3/4"x3/4"	1/8"	2,600*	4,050*	8,000*
				3/16"	5,400*	8,750*	17,000*
				1/4"	9,900*	15,850*	30,500*
				5/16"	14,500*	21,750*	N/A**
				3/8"	19,000*	29,000*	N/A**
N/A	Rockwell (Equimeter) (Sensus)	141-A*	2"x2"	1/8"	3,000*	3,700*	8,500*
				1/4"	9,000*	11,000*	26,250*
				3/8"	21,000*	25,000*	42,000*
				1/2"	N/A**	N/A**	N/A**
				5/8"	N/A**	N/A**	N/A**
N/A	Rockwell (Equimeter) (Sensus)	046*	3/4"x3/4"	1/8"	2,600*	4,050*	8,000*
				3/16"	5,400*	8,750*	17,000*
				1/4"	9,900*	14425*	24,500*
				5/16"	N/A**	N/A**	N/A**
				3/8"	N/A**	N/A**	N/A**

*Has no IRV or IRV is inadequate. Assemble with properly sized relief valve.
**Exceeds maximum inlet rating or pressure drop for orifice size.

Grayed out regulators may be found in the field but are not currently installed as new.
For inlet pressure above 500 psig MAOP and orifices above ¼" consult Gas Engineering.

RELIEF VALVE CAPACITIES AT SET POINT

(60 MAOP DOWNSTREAM)

Make	Type	Size	Orifice	Set @ 50 PSIG Capacity CFH	Set @ 60 PSIG Capacity CFH
American	Axial Flow	2"	100%	164,000	190,000
Anderson Greenwood	83	3/4" x 3/4" 3/4" x 1" 3/4" x 1"	-4 -6 -8	3,840 8,580 15,300	4,440 9,960 17,700
Fisher	289H*	1"	1"	56,500*	N/A
Fisher	289HH**	1"	1"	36,000	30,000**
Fisher	1805	3/4"	3/4"	1,500	N/A
Mooney	Single Port	1"	100%	38,000	43,350
Mooney	Single Port	2"	100%	94,000	108,000

*Maximum set point 50 psig.
**Maximum set point 53 psig to maintain 60 psig MAOP.

Grayed out relief valves may be found in the field, but are not currently installed as new.
For pressure conditions other than listed, consult Gas Engineering for proper sizing.

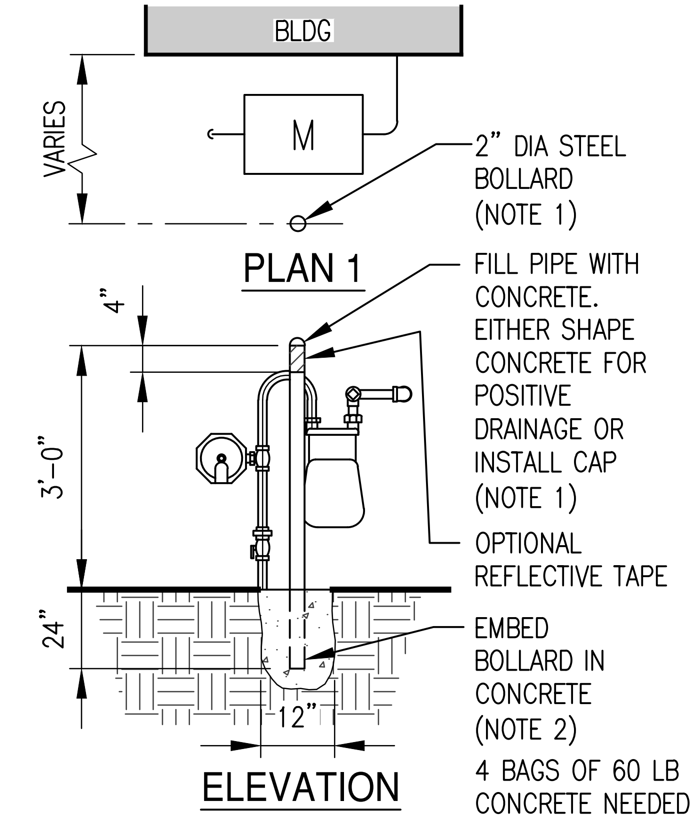
(OTHER APPLICATIONS)

Make	Type	Size	Orifice	Set @ 15" W.C. Capacity CFH	COMMENTS
Fisher	289L	1"	1"	8,300	Capacity at 2 psig build-up

.

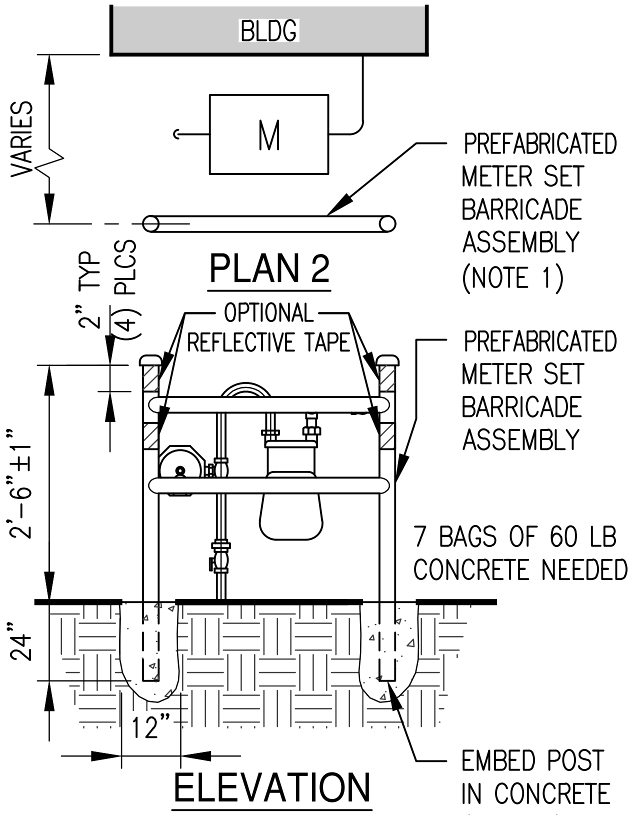
APPENDIX A – METER AND REGULATOR DRAWINGS

DRAWING	PAGE	VERSION	YEAR	DESCRIPTION
A-36712	1 of 2	12	2021	Meter Set Barricade Detail for Diaphragm Type Meters
A-36712	2 of 2	1	2015	Meter Set Barricade Detail for Close Proximity to Electric Equipment
A-38500	1 of 1	1	2021	Meter Set Stand for Flex Line Support
A-34175	1 of 2	3	2014	Single Pipe Ground Support for Meter Sets and District Regulator Stations
A-34175	2 of 2	1	2014	Double Pipe Ground Support for Meter Sets and District Regulator Stations
A-35208	1 of 1	8	2022	Residential Meter Sets, Intermediate Pressure Gas Dist. Systems
A-37102	1 of 1	7	2022	Residential Meter Sets, 2 psig Delivery, Intermediate Pressure Gas Dist Systems
A-37103	1 of 1	2	2015	Meter Set, Residential, Intermediate Pressure Gas Dist. Systems
B-35207	1 of 2	0	2016	Residential Meter Sets, High Pressure Systems with MAOP 175 PSIG or less.
B-35207	2 of 2	7	2021	Small Commercial Standard Meter Sets, High Pressure Systems with MAOP 175 PSIG or less.
C-35209	1 of 2	10	2022	Small Commercial Standard Meter Sets, Metering and Regulation
C-35209	2 of 2	7	2022	Standard Meter Sets, Typically Large Diaphragm Meter Set
B-33325	1 of 4	10	2022	2000, 3000 and 3500 Rotary Meter, Intermediate Delivery Pressure
B-33325	2 of 4	11	2022	5000 and 7000 Rotary Meters, Intermediate Delivery Pressure
B-33325	4 of 4	12	2022	11000 Rotary Meter, Intermediate Delivery Pressure
B-38205	1 of 1	4	2022	2000, 3000 and 3500 Rotary Meter, Intermediate Delivery Pressure
B-35785	1 of 1	10	2022	Standard Meter Threaded 5000 and 7000 Rotary Meters
E-37197	1 of 1	7	2022	Code 3- 2” Standard Meter Set
E-37842	1 of 1	6	2022	Welded Farm Tap Station 2” outlet
E-37970	1 of 1	6	2022	Welded Farm Tap Station, 3/4” outlet
E-33952	1 of 1	7	2021	Single Run District Reg, 2” x 4” with 2" inlet / 4" outlet
E-35783	1 of 1	7	2021	Single Run District Reg, 4” x 6” with 4" inlet / 6" outlet
E-35158	1 of 1	7	2021	Dual Run District Reg, 2” x 4” with 2" inlet / 4" outlet
L-36082	1 of 1	2	2008	Reg STA Fencing Detail



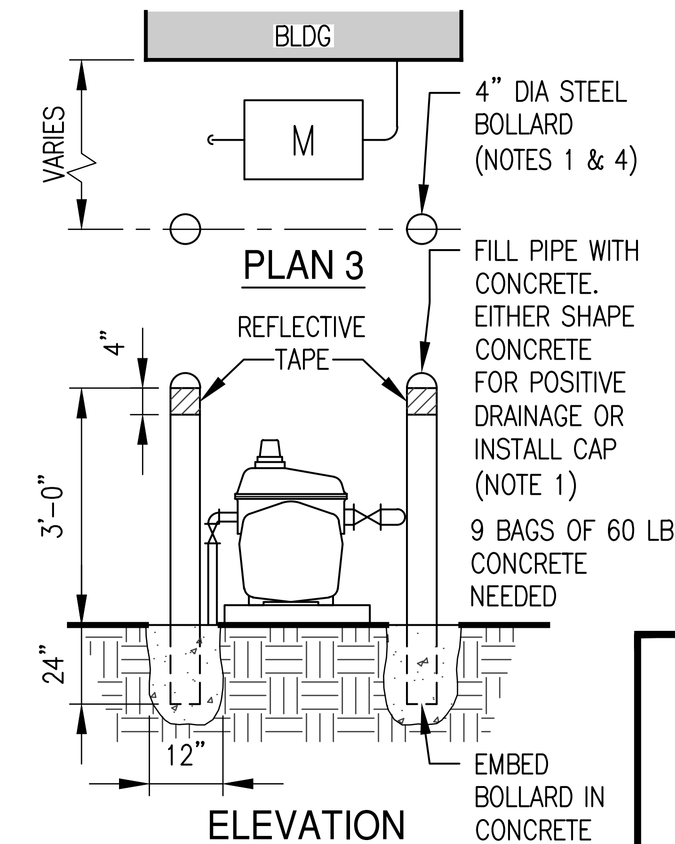
ELEVATION

RESIDENTIAL – OPTION 1



ELEVATION

RESIDENTIAL – OPTION 2



ELEVATION

COMMERCIAL

NOTES :

1. 2" WIDE REFLECTIVE TAPE – STOCK #668-0885
   4" WIDE REFLECTIVE TAPE – STOCK #668-0887
   2" STEEL BOLLARD – STOCK # 770-4752
   2" BOLLARD CAP – STOCK #770-4753
   2" PRE-FABRICATED BARRICADE – STOCK #770-4755
   4" BOLLARD CAP – STOCK #770-4756
   4" STEEL BOLLARD – STOCK #770-4757
2. AVISTA CONSTRUCTION PERSONNEL SHALL SELECT APPROPRIATE BARRICADE STYLE AND LOCATION OF BARRICADE USING BEST JUDGEMENT BASED ON EXISTING SITE CONDITIONS. CONCRETE DIMENSIONS AND BOLLARD BURY DEPTHS SHOWN ARE PREFERRED. DEVIATIONS TO THESE DIMENSIONS MAY BE APPROVED BY THE LOCAL MANAGEMENT IF DIMENSIONS ARE NOT PRACTICABLE TO ACHIEVE.
3. SEE SHEET 2 FOR CLEARANCE AND GROUNDING REQUIREMENTS WHEN INSTALLED NEAR PRIMARY VOLTAGE ELECTRICAL EQUIPMENT.
4. A SINGLE BOLLARD IS AN OPTION IN COMMERCIAL APPLICATIONS IF THE FIELD CONDITIONS SUPPORT.

DISTRIBUTION - GAS
STANDARD
METER SET BARRICADE/ BOLLARD DETAIL
FOR DIAPHRAGM TYPE METERS

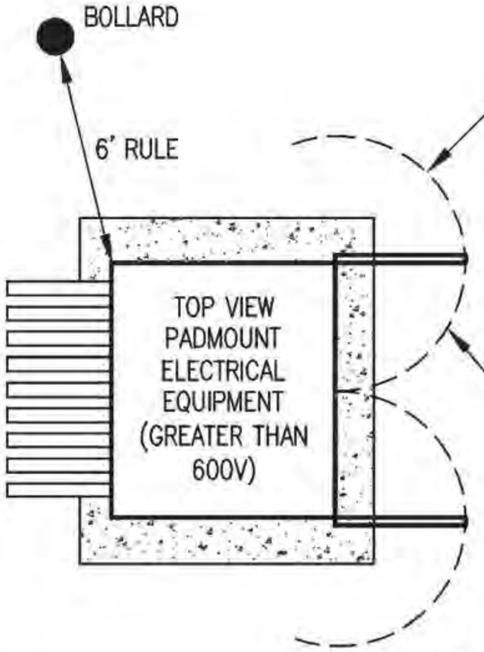
AVISTA CORP
SPOKANE, WASHINGTON

NO	DATE	REVISION	BY	CKD
12	11-5-21	STANDARDS UPDATE	CGD	RMA

SCALE: NONE
DATE: 11-07-07
DSN: T.BARRY
DR: S.GRAF
CKD: TLB
CKD: TJH
NTD:
NTD: CL
APPROVED
DATE: 11-13-07
SHT 1 OF 2
A-36712

AUTOCAD DWG

11/5/2021 8:55 AM

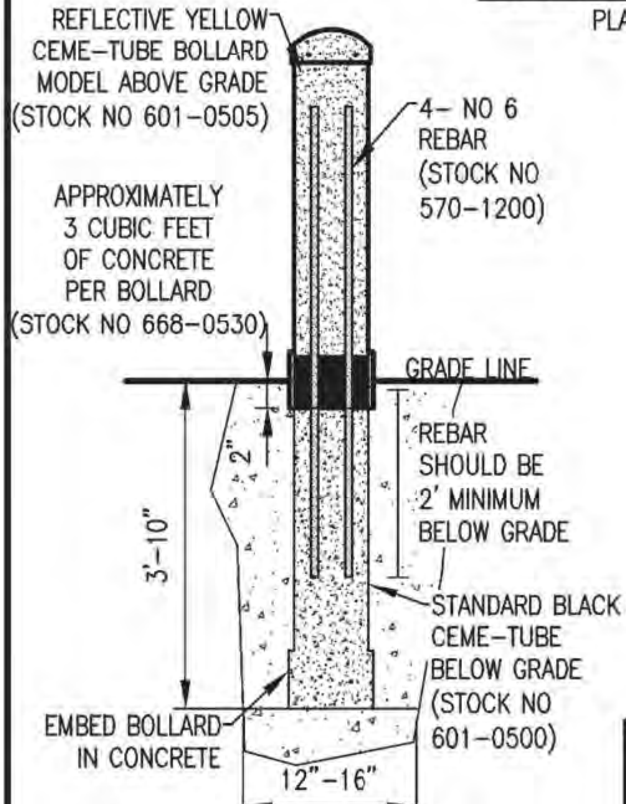


6' SEPARATION IS PREFERRED BETWEEN STEEL BOLLARDS AND PRIMARY VOLTAGE ELECTRIC EQUIPMENT (GREATER THAN 600V). IF THE 6' SEPARATION CANNOT BE ACHIEVED, ONE OF THE FOLLOWING IS REQUIRED:

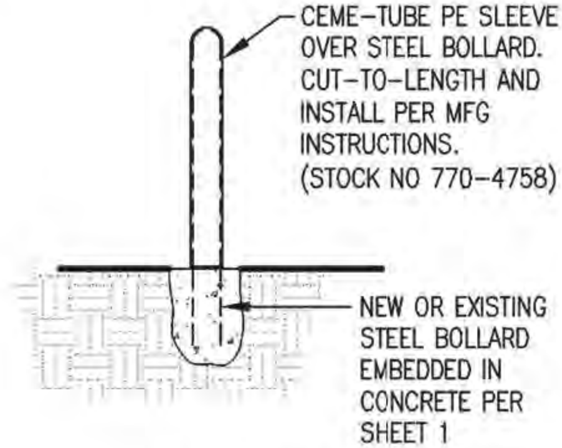
1. INSTALL NON-CONDUCTIVE BOLLARD PER DETAIL 1 BELOW
2. INSTALL NON-CONDUCTIVE SLEEVE OVER STEEL BOLLARD PER DETAIL 2 BELOW
3. COORDINATE WITH ELECTRIC PROVIDER TO BOND THE STEEL BOLLARD TO THE ELECTRIC EQUIPMENT GROUND

NOTE:
IF THERE ARE QUESTIONS ON THE APPLICATION OF THIS STANDARD, CONTACT GAS ENGINEERING

BOLLARD LOCATION
PLAN VIEW



DETAIL 1
NON-CONDUCTIVE BOLLARD
ELEVATION



DETAIL 2
NON-CONDUCTIVE SLEEVE
ELEVATION

DISTRIBUTION - GAS STANDARD
METER SET BARRICADE DETAIL FOR CLOSE PROXIMITY TO ELECTRIC EQUIPMENT
AVISTA CORP
SPOKANE, WASHINGTON

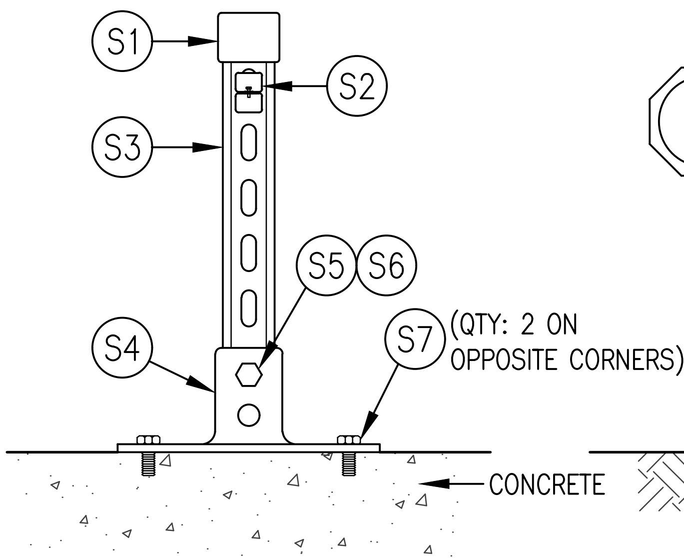
NO	DATE	REVISION	BY	CKD
1	8-26-15	STANDARDS UPDATE	CGD	DRS
0	10-10-14	STANDARDS UPDATE	JAJ	JAF

SCALE: NONE	DATE: 10-10-14	APPROVED: [signature] 10-20-14
DSN: FORT	CKD: TJH	DATE
DR: JACOBSEN	NTD:	SHT 2 OF 2
CKD:	NTD: CL	A-36712

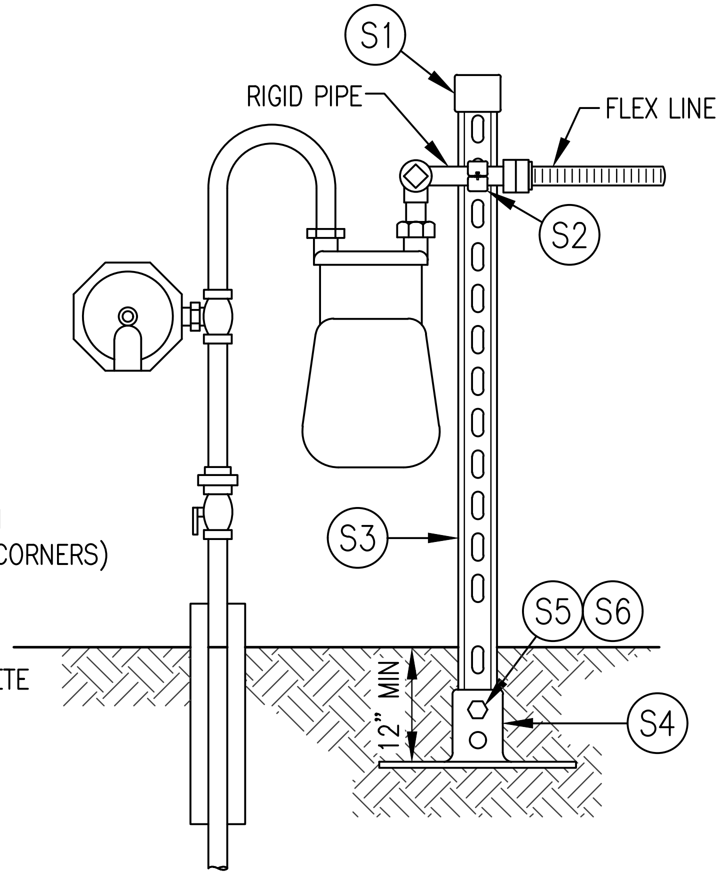
MATERIAL LIST

NO	STOCK NO	QTY	DESCRIPTION
S1	770-7848	1	UNISTRUT PLASTIC END CAP, WHITE
S2	570-2116	1	PIPE CLAMP, 1", GALVANIZED
S3	770-7844	1	UNISTRUT CHANNEL, 1⅝"x1⅝", 12 GAUGE, GALVANIZED
S4	770-7851	1	POST BASE FOR UNISTRUT CHANNEL, 6" x 6" ELECTRO-PLATED ZINC
S5	573-1021	1	UNISTRUT CHANNEL NUT, ½", WITH LONG SPRING
S6	770-7852	1	HEX CAP SCREW, ½", 2"L, SILVER ZINC PLATED
S7	FAB SHOP	2	CONCRETE ANCHOR BOLT, ⅜" DIAMETER

NOTE:
S2 TO BE ATTACHED AS CLOSE AS PRACTICAL TO THE OUTLET PIPING (OR A-9 VALVE) OF THE METER.



OPTION 1:
ANCHOR TO CONCRETE OR ASPHALT



OPTION 2:
DIRECT BURY

DISTRIBUTION - GAS
STANDARD
METER SET STAND
FOR FLEX LINE SUPPORT
AVISTA CORP
SPOKANE, WASHINGTON

1	11-5-21	STANDARDS UPDATE	CGD	RMA
0	10-14-20	ADDED TO STANDARDS	CGD	RMA
NO	DATE	REVISION	BY	CKD

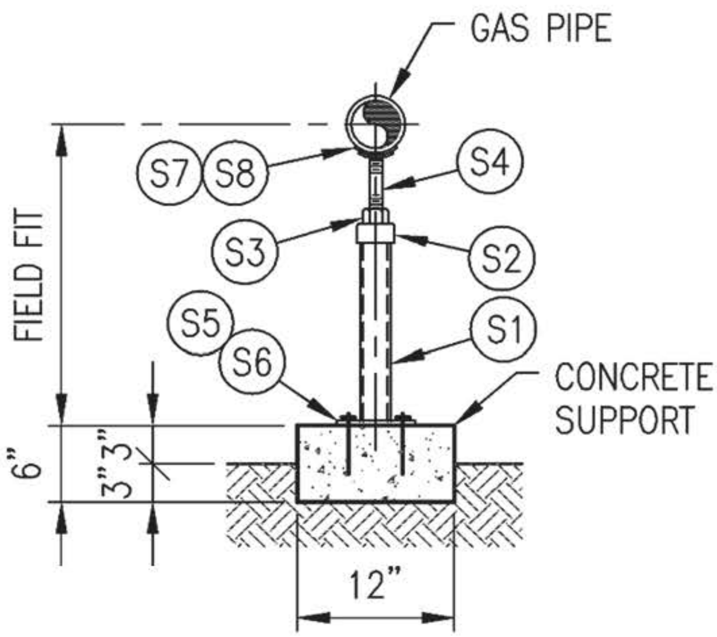
NONE — SCALE
2-4-2020 — DATE
DSN ANDERSON   CKD
DR DARNELL   NTD
CKD RMA   NTD RLB

APPROVED
10-14-20
DATE
SHT 1 OF 1
A-38500

AUTOCAD DWG

SINGLE PIPE SUPPORT MATERIAL LIST

S1	770-6110	6'	PIPE, 2"ø, STEEL, BARE, STD WALL
S2	770-0950	1	WELD CAP, 2", STD WALL
S3	FAB SHOP	1	HD HEX NUT, 1"ø
S4	FAB SHOP	1	STUD, 1"ø x 10" LONG (ALL THREAD)
S5	FAB SHOP	1	PL 3/8" x 6" x 6" LONG (BASE PLATE)
S6	FAB SHOP	2	CONCRETE ANCHOR BOLTS, 3/8"ø
S7	FAB SHOP	1	PL 1/4" x 2" x 7" LONG (SADDLE)
S8	770-3210	1	INSULATING MATERIAL FOR SADDLE, 1/16" THICK



CONSTRUCTION NOTES

2"CAP	DRILL 1.125 HOLE IN TOP
2" PIPE	FIELD FIT, (10" THREADED STUD PROVIDES HEIGHT ADJUSTMENT)
PAINT	REMOVE ALL RUST AND SCALE, APPLY ONE COAT OF PRIMER, AND TWO COATS OF GRAY METER ENAMEL

NO	DATE	REVISION	BY	CKD
3	8-6-14	STANDARDS UPDATE	JAJ	DRS
2	10-09	CORRECT TO DATE	TJH	KOB
1	1-97	CORRECT TO DATE	JW	MF

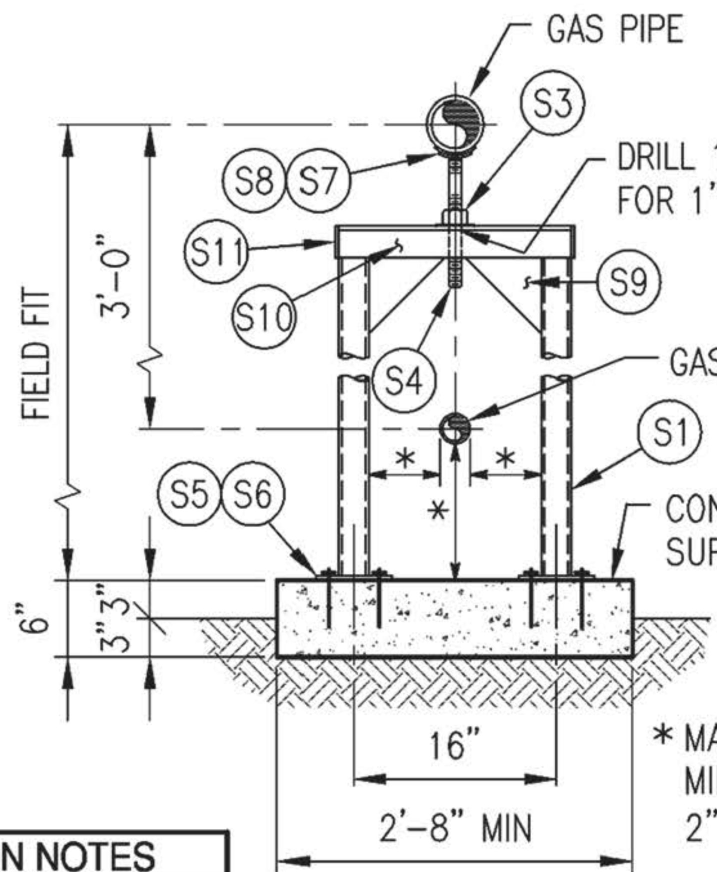
DISTRIBUTION - GAS
STANDARD
SINGLE PIPE GROUND SUPPORT FOR METER SETS AND DISTRICT REGULATOR STATIONS

AVISTA CORP
SPOKANE, WASHINGTON

SCALE: 1" = 1'-0"	DATE: 11-05-93	APPROVED: [signature] 11-09-93 DATE
DSN BURGER	CKD	SHT 1
DR PICKUP	NTD	OF 2
CKD	NTD JW	A-34175

AUTOCAD DWG

PIPE SUPPORT MATERIAL LIST			
S1	770-6110	10'	PIPE, 2"ø, STEEL, BARE, STD WALL
S2	770-0950	1	WELD CAP, 2", STD WALL
S3	FAB SHOP	1	HD HEX NUT, 1"ø
S4	FAB SHOP	1	STUD, 1"ø x 10" LONG (ALL THREAD)
S5	FAB SHOP	2	PL 3/8" x 6" x 6" LONG (BASE PLATE)
S6	FAB SHOP	4	CONCRETE ANCHOR BOLTS, 3/8"ø
S7	FAB SHOP	1	PL 1/4" x 2" x 7" LONG (SADDLE)
S8	770-3210	1	INSULATING MATERIAL FOR SADDLE, 1/16" THICK
S9	FAB SHOP	1	PL 1/8" x 6" x 6" (CUT TO FORM 2 EA) GUSSETS
S10	FAB SHOP	2	TS 2½" x 2½" x 3/16"
S11	FAB SHOP	2	BAR 2½" x 3/16" x 2½" LONG



* MAINTAIN MINIMUM OF 2" CLEARANCE

CONSTRUCTION NOTES	
2"CAP	DRILL 1.125 HOLE IN TOP
2" PIPE	FIELD FIT, (10" THREADED STUD PROVIDES HEIGHT ADJUSTMENT)
PAINT	REMOVE ALL RUST AND SCALE, APPLY ONE COAT OF PRIMER, AND TWO COATS OF GRAY METER ENAMEL

DISTRIBUTION - GAS
STANDARD
DOUBLE PIPE GROUND SUPPORT FOR METER SETS AND DISTRICT REGULATOR STATIONS

AVISTA CORP
SPOKANE, WASHINGTON

1" = 1'-0"	10-16-09
SCALE	DATE
DSN WEBB	CKD KDB
DR TJH	NTD
CKD	NTD

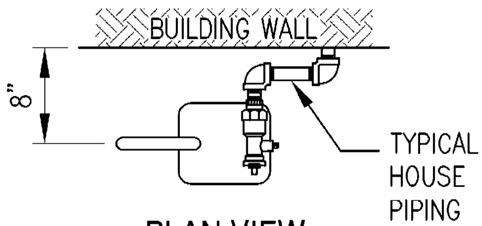
APPROVED
10-19-09
DATE
SHT 2 OF 2
A-34175

NO	DATE	REVISION	BY	CKD
1	8-6-14	STANDARDS UPDATE	JAJ	DRS

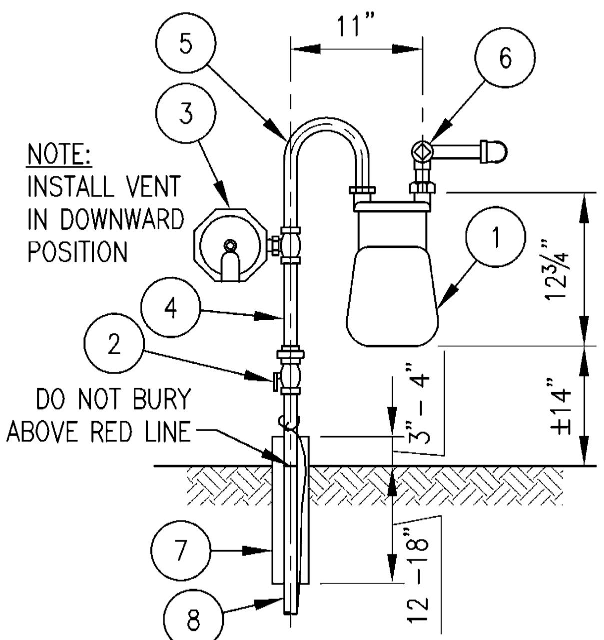
MATERIAL LIST

	QTY	STOCK NO	SIZE	DESCRIPTION
	1	MTR SHOP	20 LT	CLASS "A" METER
	2	770-8685	¾"	INSULATED SERVICE VALVE, LOCKWING
*	3	MTR SHOP	¾" x 1"	CLASS "A" REGULATOR W/2 PSI CAPABILITY
*	4	732-5464	¾" x 6"	NIPPLE, THD, SCH 40
*	5	–	1"x 20 LT	U-BEND, GR A, THD, COATED
	6	770-8515	20LT x 1"	A-9 VALVE, FNPT INSULATED UNION OUTLET
	7	770-6430	4"	CORRUGATED PVC
	8	770-7220	¾"	ANODELESS SERVICE RISER

* ITEMS 3-5 ARE INCLUDED WITH STOCK NUMBER 770-4932



PLAN VIEW



ELEVATION

7" W.C. OR 1/4" PSIG DELIVERY (CODE 1)

CONSTRUCTION NOTES:

1. PAINT FITTINGS TO CONFORM WITH METER.
2. METER SET DIMENSIONS, LENGTH - DEPTH - HEIGHT 20" x 9" x 33".
3. ALCOVE DIMENSION, LENGTH - DEPTH- HEIGHT 21" x 14" x 39".
4. CENTERLINE OF GAS SERVICE RISER TO BE 8" FROM BUILDING.
5. TERMINATE TRACER WIRE BELOW THE METER VALVE, USING HALF-HITCH KNOT. DO NOT TAPE TRACER TO RISER.

SUPERSEDES A-35208 SHT 1, DATED 2-28-94
A-35208 SHT 2, DATED 9-29-04

DISTRIBUTION - GAS
STANDARD
GAS METER SETS, RESIDENTIAL
INTERMEDIATE PRESSURE GAS DIST. SYSTEMS

AVISTA CORP
SPOKANE, WASHINGTON

NO	DATE	REVISION	BY	CKD
8	8-24-22	UPDATE RISER STOCK NO	TJH	DRS
7	10-10-19	UPDATE ITEM #6	CGD	DRS
6	8-26-15	STANDARDS UPDATE	CGD	DRS

SCALE: NONE | DATE: 9-15-04
DSN: TLB | CKD: WB
DR: JW | NTD:
CKD: TB | NTD: JW

APPROVED: [signature]
DATE: 9-29-04
SHT 1 OF 1

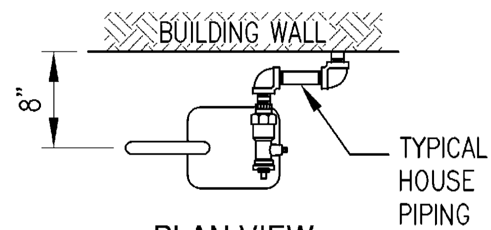
A-35208

AUTOCAD DWG

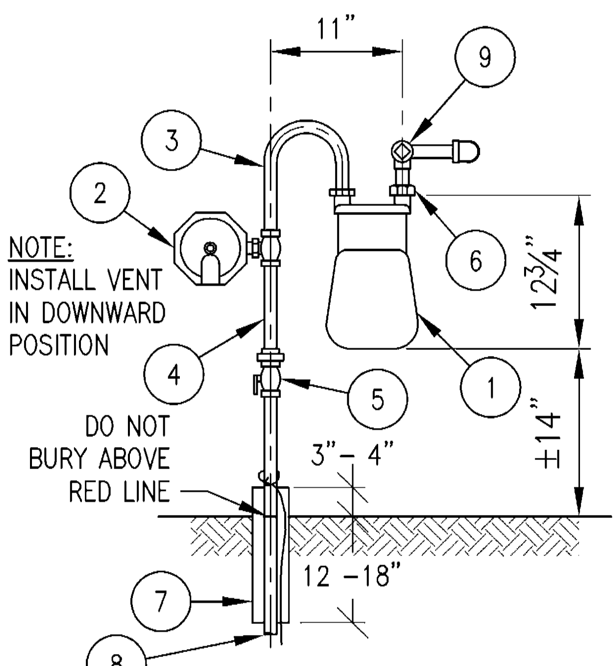
MATERIAL LIST

	QTY	STOCK NO	SIZE	DESCRIPTION
	1	MTR SHOP	20 LIGHT	CLASS "A" METER
*	2	MTR SHOP	¾" x 1"	CLASS "B" REGULATOR W/2 PSI CAPABILITY
*	3	–	1" x 20LT	U-BEND, GR A, THD, COATED
*	4	732-5464	¾" x 6"	NIPPLE, THD, SCH 40
	5	770-8525	¾"	INSULATED SERVICE VALVE, LOCKWING
	6	770-4936	1"	SWIVEL, 20LT, GALVANIZED
	7	770-6430	4"	CORRUGATED PVC
	8	770-7220	¾"	ANODELESS SERVICE RISER
	9	770-8515	20LT x 1"	A-9 VALVE, FNPT INSULATED UNION OUTLET

* ITEMS 2-4 ARE INCLUDED WITH STOCK NUMBER 770-4932



PLAN VIEW



ELEVATION

2 PSIG DELIVERY (CODE 4)

CONSTRUCTION NOTES:

1. PAINT FITTINGS TO CONFORM WITH METER.
2. METER SET DIMENSIONS, LENGTH - DEPTH - HEIGHT 18" x 9" x 27".
3. ALCOVE DIMENSION, LENGTH - DEPTH - HEIGHT 19" x 14" x 33".
4. CENTERLINE OF GAS SERVICE RISER TO BE 8" FROM BUILDING.
5. TERMINATE TRACER WIRE BELOW THE METER VALVE, USING HALF-HITCH KNOT. DO NOT TAPE TRACER TO RISER.

SUPERSEDES A-35208 SHT 3, DATED 1-22-97

DISTRIBUTION - GAS
STANDARD
GAS METER SETS, 2 PSIG RESIDENTIAL
INTERMEDIATE PRESSURE GAS DIST SYSTEMS

AVISTA CORP
SPOKANE, WASHINGTON

NO	DATE	REVISION	BY	CKD
7	8-24-22	UPDATE RISER STOCK NO	TJH	DRS
6	10-10-19	REMOVE PETE'S PLUG DETAIL	CGD	DRS
5	9-15-15	STANDARDS UPDATE	CGD	DRS

SCALE: NONE DATE: 10-20-09

DSN WEBB CKD JAW
DR TJH NTD
CKD NTD CL

APPROVED: [signature] DATE: 10-21-09

SHT 1 OF 1 A-37102

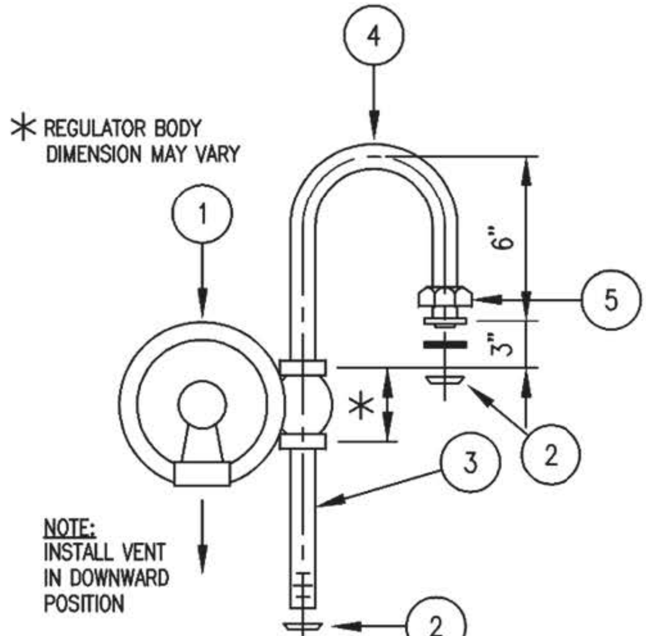
10/4/2022 1:15 PM

AUTOCAD DWG

MATERIAL LIST			
NO	SIZE	DESCRIPTION	QTY
1	¾"x1"	REGULATOR, 180° BODY, SET@ 7" W.C. (DOMESTIC)	1
2	AS REQ'D	THREAD PROTECTIVE CAPS	2
3	¾"	NIPPLE, PIPE, SCH 40, STANDARD WALL, 6" LONG (DOMESTIC)	1
4	1" x 20LT	U-BEND, GRADE A, THD, COATED	1
5	1"	NUT, METER SWIVEL, 20 LT	1

CONSTRUCTION NOTES:

1. UNIT TO BE FACTORY PREPARED AND POWDER COATED, OR PAINTED WITH ONE ZINC-RICH PRIMER COAT AND TWO TOPCOATS OF EPOXY PAINT GRAY IN COLOR.
2. UNIT TO BE PRESSURE TESTED TO 90 PSIG MINIMUM.
3. UNIT TO BE SHIPPED WITH THREAD PROTECTIVE CAPS INSTALLED.
4. ASSEMBLY SHALL BE PACKAGED AS ONE UNIT.
5. ITEMS 1-5 ARE INCLUDED WITH STOCK NUMBER 770-4932



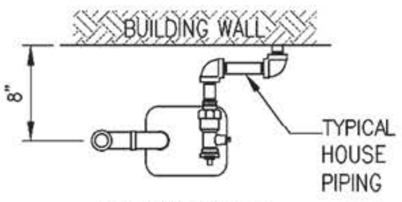
SUPERSEDES A-35208 SHT 4, DATED 11-28-05
A-35208 SHT 5, DATED 11-28-05

DISTRIBUTION - GAS
STANDARD
GAS METER SETS, RESIDENTIAL
INTERMEDIATE PRESSURE GAS DIST. SYSTEMS
AVISTA CORP
SPOKANE, WASHINGTON

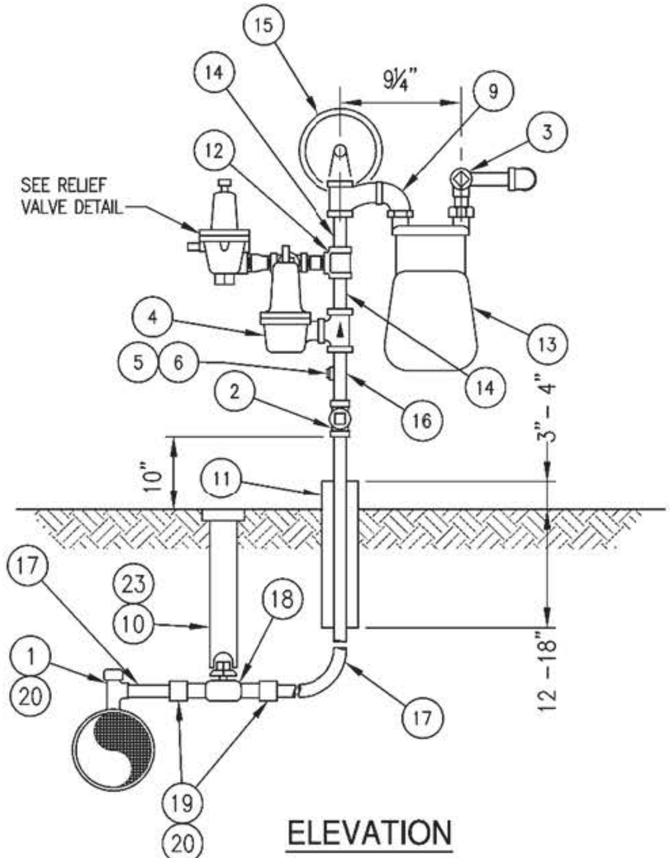
NO	DATE	REVISION	BY	CKD
2	8-26-15	STANDARDS UPDATE	CGD	DRS
1	8-6-14	MINOR CORRECTION	JAJ	DRS

SCALE: NONE	DATE: 10-20-09	APPROVED
DSN WEBB	CKD QAW	DATE 10-21-09
DR TJH	NTD	SHT 1
CKD	NTD CL	OF 1

A-37103



PLAN VIEW



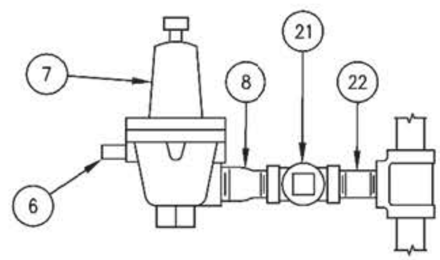
ELEVATION

LOADS BELOW 275 CFH

* THIS IS THE RECOMMENDED REGULATOR. SEE "FARM TAP REGULATORS" TABLE UNDER SECTION 2.24, METER & REGULATORS TABLES, AND DRAWINGS FOR OTHER ACCEPTABLE FARM TAP REGULATORS.

DIMENSIONS

RISER CENTER TO WALL: 8"
SET DIMENSIONS L x D x H:
17" x 9" x 31"
ALCOVE DIMENSIONS:L x D x H:
41" x 27" x 55"



RELIEF VALVE DETAIL

MATERIAL LIST

NO	STOCK NO	SIZE	DESCRIPTION
1	770-7822	1"	MUELLER H-17656 CURB STOP TEE
2	770-8565	¾"	MUELLER VALVE, LOCKWING, NON-INS, 500 PSIG
3	770-8515	1"	VALVE, THD, WITH INSULATED UNION, A-9
* 4	MTR SHOP	¾"	FISHER, 627R, REGULATOR, ⅛" ORIFICE, SET AT 30 PSIG
5	770-8851	¼"	THREAD-O-LET, CL3000
6	770-6670	¼"	RALSTON QUICK TEST FITTING, 3000 PSIG
7	MTR SHOP	1"	FISHER, 289HH, RELIEF VALVE, SET AT 45 PSI
8	770-5325	1" x ¾"	NIPPLE, SWAGE
9	770-4927	1"	ELBOW, SWIVEL
10	770-0613	2"	VALVE BOX, BOTTOM SECTION
11	770-6430	4"	CORRUGATED PVC
12	732-7690	¾"	TEE, THD, SCH 40
13	MTR SHOP	20 LT	CLASS "A" METER
14	732-5446	¾"	NIPPLE, THD, SCH 40, 3" LONG
15	MTR SHOP	¾" x 1"	CLASS "A" REGULATOR
16	732-5456	¾"	NIPPLE, THD, SCH 80, 4" LONG
17	770-6228	¾"	PIPE, STEEL, FBE
18	770-8685	¾"	BALL VALVE, ANSI 300, WxW
19	SHOP	¾"	SOCKET WELD SPACER RINGS
20	770-1330	¾"	COUPLING, SOCKET WELD, CL3000
21	770-1285	¾"	BALL VALVE, 600 PSIG, THD
22	732-5440	¾"	NIPPLE, THD, SCH 40, 2" LONG
23	770-0635	–	VALVE BOX, TOP SECTION AND LID

NOTE

CONTACT GAS ENGINEERING IF THE SYSTEM MAOP IS GREATER THAN 175 PSIG FOR DESIGN ASSISTANCE.

SUPERSEDES A-35207s001r09, DATED 2-28-94

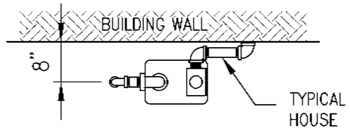
DISTRIBUTION – GAS
RESIDENTIAL STANDARD GAS METER SETS
HIGH PRESSURE SYSTEMS
WITH MAOP 175 PSIG OR LESS
AVISTA CORP
SPOKANE, WASHINGTON

NO	DATE	REVISION	BY	CKD	AS BUILT
0	6-27-16	STANDARDS UPDATE	JAJ	DRS	

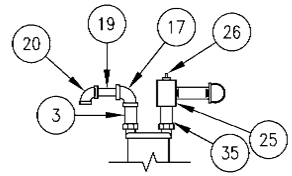
SCALE: NONE
DATE: 9-23-16
DSN: DRS   CKD:
DR: JAJ   NTD:
CKD: DRS   NTD: CL
APPROVED: [signature] 9-23-16 (DATE)
SHT 1 OF 2
B-35207

AUTOCAD DWG

*THIS IS THE RECOMMENDED REGULATOR. SEE "FARM TAP REGULATORS" TABLE UNDER SECTION 2.24, METER & REGULATORS TABLES, AND DRAWINGS FOR OTHER ACCEPTABLE FARM TAP REGULATORS.

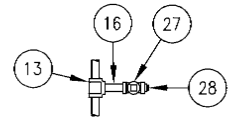


PLAN

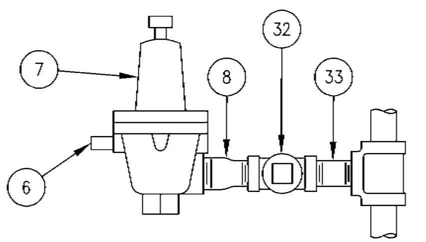


DETAIL

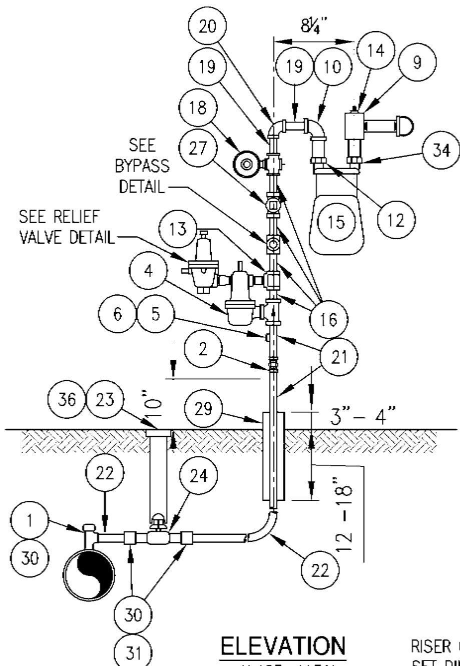
AL800, 750AL, AL1000



BYPASS DETAIL



RELIEF VALVE DETAIL



ELEVATION

AL425, 415AL

DIMENSIONS

RISER CENTER TO WALL: 8"
SET DIMENSIONS L x D x H: 36" x 9" x 38"
ALCOVE DIMENSIONS L x D x H: 60" x 27" x 60"

MATERIAL LIST

NO	STOCK NO	SIZE	DESCRIPTION
1	770-7822	1"	MUELLER H-17656 CURB STOP TEE
2	770-8565	3/4"	MUELLER VALVE, LOCKWING, NON-INS, 500 PSIG
3	770-4976	1 1/2"	SWIVEL, 45 LT, GALVANIZED
* 4	MTR SHOP	3/4"	FISHER, 627R, REGULATOR, 1/8" ORIFICE, SET AT 30 PSIG
5	770-8851	1/4"	THREAD-O-LET, CL3000
6	770-6670	1/4"	RALSTON QUICK-TEST FITTING, 3000 PSIG
7	MTR SHOP	1"	FISHER, 289HH, RELIEF VALVE, SET AT 45 PSIG
8	770-5325	1"x3/4"	NIPPLE, SWAGE
9	770-8810	1 1/4"	VALVE, 3-WAY, THD
10	MTR SHOP	1 1/4"x1"	ELBOW, SWIVEL, 90°, REDUCING
11	732-6121	1"	PLUG, THREADED, CL3000
12	770-4956	1 1/4"	SWIVEL, 30 LT, GALVANIZED
13	732-7690	3/4"	TEE, THD, SCH 40
14	732-6124	1 1/4"	PLUG, THREADED, CL3000
15	MTR SHOP		CLASS "B" METER
16	732-5446	3/4"	NIPPLE, THD, SCH 40, 3" LONG
17	732-1785	1 1/2"x1"	ELBOW, 90° TBE, REDUCING
18	MTR SHOP		CLASS "B" REGULATOR
19	732-5486	1"	NIPPLE, THD, SCH 40, 3" LONG
20	732-1731	1"	90° ELBOW, THD
21	732-5456	3/4"	NIPPLE, THD, SCH 80, 4" LONG
22	770-6228	3/4"	PIPE, STEEL, FBE
23	770-0613	2"	VALVE BOX, BOTTOM SECTION
24	770-8685	3/4"	BALL VALVE, ANSI 300, WxW
25	770-8820	1 1/2"	VALVE, 3-WAY, THD
26	732-6127	1 1/2"	PLUG, THREADED, CL3000
27	770-8560	3/4"	VALVE, LOCKWING, NON INS, 175 PSIG
28	732-6118	3/4"	PLUG, THREADED, CL3000
29	770-6430	4"	CORRUGATED PVC
30	SHOP	3/4"	SOCKET WELD, SPACER RINGS
31	770-1330	3/4"	COUPLING, SOCKET WELD, CL3000
32	770-1285	3/4"	BALL VALVE, 600 PSIG, THD
33	732-5440	3/4"	NIPPLE, THD, SCH 40, 2" LONG
34	770-4951	1 1/4"	SWIVEL, 30LT, GALVANIZED, INSULATED
35	770-4970	1 1/2"	SWIVEL, 45LT, GALVANIZED, INSULATED
36	770-0635	–	VALVE BOX, TOP SECTION AND LID

NOTE

CONTACT GAS ENGINEERING IF THE SYSTEM MAOP IS GREATER THAN 175 PSIG FOR DESIGN ASSISTANCE.

NO	DATE	REVISION	BY	CKD	AS BUILT
7	10-12-21	UPDATED THREADED PLUG	CGD	DRS	
6	4-11-16	STANDARDS UPDATE	JAJ	DRS	
5	8-26-15	STANDARDS UPDATE		CGD	DRS

DISTRIBUTION – GAS
SMALL COMMERCIAL STANDARD GAS METER SETS
HIGH PRESSURE SYSTEMS
WITH MAOP 175 PSIG OR LESS

AVISTA CORP
SPOKANE, WASHINGTON

SCALE: NONE | DATE: 2-24-97
DSN: BURGER | CKD: AB
DR: TW | NTD:
CKD: | NTD: JW
APPROVED: Jody [signature] 2-27-96
SHT 2 OF 2 | B-35207

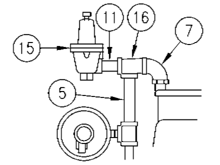
AUTOCAD DWG

10/12/2021 1:16 PM
B-35207s002r07.dwg

C-35209

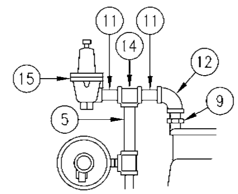
MATERIAL LIST

DESCRIPTION			METER STYLE AND SIZE			
			AL425	AC630	AL800	AL1000TC
A. SERVICE RISER TO METER OULET		INCHES	15¼	15¼	19¼	19¼
B. METER OUTLET TO METER BOTTOM		INCHES	18⅞	18⅞	27½	27½
C. METER BOTTOM TO METER GRADE (APPROX.)		INCHES	8–12	8–12	8–12	8–12
SET DIMENSIONS	LENGTH–DEPTH–HEIGHT	INCHES	24 x 11 x 21	24 x 11 x 21	28 x 14 x 33	28 x 14 x 33
ALCOVE DIMENSIONS	LENGTH–DEPTH–HEIGHT	INCHES	48 x 18 x 48	48 x 18 x 48	52 x 23 x 57	52 x 23 x 57
1. METER	CONNECTION SIZE	INCHES	1¼	1¼	1½	1½
	CASE PRESSURE	PSIG	10	25	20	25
	REVERSIBLE INDEX		NO	NO	YES	YES
2. REGULATOR, CLASS B, ¾ x 1		INCHES	¾ x 1	¾ x 1	¾ x 1	¾ x 1
3. SERVICE VALVE, INSULATED TYPE, THD		INCHES	¾	¾	¾	¾
		STOCK NO	770–8525	770–8525	770–8525	770–8525
4. NIPPLE, THD, SCH 40		INCHES	8	8	12	12
		INCHES	¾ x 3	¾ x 3	¾ x 12	¾ x 12
		STOCK NO	732–5446	732–5446	CUT IN FIELD	CUT IN FIELD
5. NIPPLE, THD, SCH 40		INCHES	1 x 6	1 x 6	1 x 8	1 x 8
		STOCK NO	732–5504	732–5504	732–5510	732–5510
6. U–BEND, GR A, THD, COATED		INCHES	1 x 30LT	1 x 30LT	1 x 45LT	1 x 45LT
		STOCK NO	770–4485	770–4985	770–4990	770–4990
7. SWIVEL, ELBOW, 90 DEG, THD		INCHES	1¼	1¼	NA	NA
		STOCK NO	METER SHOP	METER SHOP		
8. VALVE, 3–WAY, THD		INCHES	1¼	1¼	1½	1½
		STOCK NO	770–8810	770–8810	770–8820	770–8820
9. SWIVEL, STRAIGHT, NON–INSULATING		INCHES	1¼	1¼	1½	1½
		STOCK NO	770–4956	770–4956	770–4976	770–4976
10. PLUG, THD, CL 3000		INCHES	1¼	1¼	1½	1½
		STOCK NO	732–6124	732–6124	732–6127	732–6127
11. NIPPLE, THD, SCH 40		INCHES	1 x 3	1 x 3	1 x 3	1 x 3
		STOCK NO	732–5486	732–5486	732–5486	732–5486
12. ELBOW, 90 DEG, TBE, REDUCING, SCH 40		INCHES	NA	NA	1½ x 1	1½ x 1
		STOCK NO			732–1785	732–1785
13. METER SET ASSEMBLY, 30LT		INCHES	30LT x 1	30LT x 1	NA	NA
		STOCK NO	770–4923	770–4923		
14. TEE, THD, SCH 40		INCHES	NA	NA	1 x 1 x 1	1 x 1 x 1
		STOCK NO			732–7696	732–7696
15. RELIEF VALVE, FISHER, 289L OR 289H		INCHES	1	1	1	1
		STOCK NO	METER SHOP	METER SHOP	METER SHOP	METER SHOP
16. TEE, THD, REDUCING, SCH 40		INCHES	1¼ x 1	1¼ x 1	NA	NA
		STOCK NO	METER SHOP	METER SHOP		
17. CORRUGATED PVC		INCHES	4	4	4	4
		STOCK NO	770–6430	770–6430	770–6430	770–6430
18. RISER, ANODELESS, WITH BYPASS		INCHES	¾	¾	¾	¾
		STOCK NO	770–7222	770–7222	770–7222	770–7222
19. RISER, ANODELESS, WITHOUT BYPASS		INCHES	¾	¾	¾	¾
		STOCK NO	770–7220	770–7220	770–7220	770–7220
20. METER OUTLET BYPASS VALVE, FNPT INSULATED UNION OUTLET		INCHES	30LT x 1¼	30LT x 1¼	NA	NA
		STOCK NO	770–8517	770–8517		



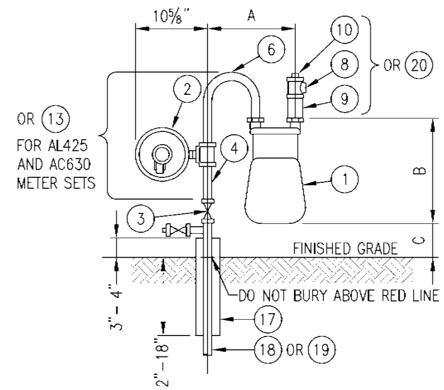
DETAIL FOR RELIEF

(IF REQUIRED)
AL425, 415AL, AC630



DETAIL FOR RELIEF

(IF REQUIRED)
AL800, 750AL, AL1000



TYPICAL SMALL METER SET

AL425, 415AL, AC630, AL800
750AL, AL1000

NOTE:

1. VENT ON REGULATOR SHOULD BE IN THE DOWNWARD POSITION TO PREVENT WATER ACCUMULATION OR NEED TO INSTALL A VENT ELBOW INSTALLED IN A DOWNWARD POSITION.
2. REMOVE, CUT DOWN, OR PADLOCK 3–WAY VALVE HANDLE AFTER INSTALLATION.

SUPERSEDES B–35209 SHT 1, DATED 2–28–94

NO	DATE	REVISION	BY	CKD
10	8–24–22	ADDED 30LT METER SET ASSEMBLY TO MATERIAL LIST	TJH	DRS
9	10–12–21	UPDATED THREADED PLUG	CGD	DRS
8	10–10–19	ADDED A–9 VALVE FOR AL425 METER	CGD	DRS
7	9–15–15	STANDARDS UPDATE	CGD	DRS
6	3–9–15	STANDARDS UPDATE	JAJ	DRS

DISTRIBUTION - GAS
METERING & REGULATION
STANDARD METER SET
TYPICAL SMALL DIAPHRAGM METER SETS

AVISTA CORP
SPOKANE, WASHINGTON

SCALE NONE | DATE 2–22–94 | APPROVED David Howell | 2–25–11 DATE
DSN T BARRY | CKD | DR WOC | NTD | CKD | NTD
SHT 1 OF | C-35209

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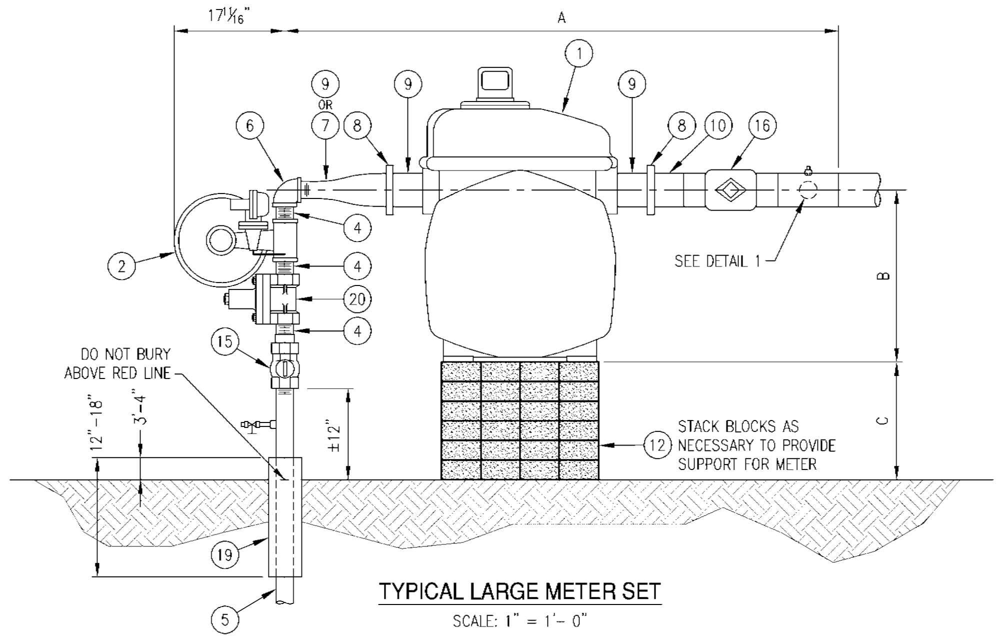
C-35209

MATERIAL LIST

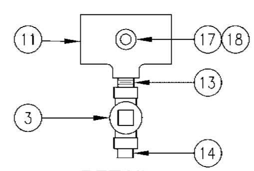
DESCRIPTION			METER STYLE AND SIZE		
			AL1400	AL2300	AL5000
A. SERVICE RISER TO METER SET OUTLET		INCHES	49	68	73
B. METER OUTLET TO METER BOTTOM		INCHES	15	18	23
C. METER BOTTOM TO GROUND		INCHES	20	17	12
SET DIMENSIONS	LENGTH-DEPTH-HEIGHT	INCHES	66 x 16 x 49	85 x 19 x 50	90 x 24 x 52
ALCOVE DIMENSIONS	LENGTH-DEPTH-HEIGHT	INCHES	90 x 26 x 73	109 x 36 x 74	114 x 38 x 76
1. METER	CONNECTION SIZE	INCHES	2	4	4
	CASE PRESSURE	PSIG	100	100	100
	REVERSIBLE INDEX		YES	YES	YES
2. REGULATOR, CLASS C		INCHES	2 x 2	2 x 2	2 x 2
3. SERVICE VALVE, LOCKING, NON-INS, 175 PSIG		INCHES	2	2	2
		STOCK NO	770-8592	770-8592	770-8592
	CENTER TO WALL	INCHES	12	20	20
4. CLOSE NIPPLE, THD, SCH 40		INCHES	2	2	2
		STOCK NO	732-5274	732-5274	732-5274
5. ANODELESS RISER, WITH BYPASS		INCHES	2	2	2
		STOCK NO	770-7230	770-7230	770-7230
6. ELBOW, 90 DEGREES, THD SCH 40		INCHES	2	2	2
		STOCK NO	732-1740	732-1740	732-1740
7. SWAGE NIPPLE, THD x VIC		INCHES	NA	2 x 4 x 9L	2 x 4 x 9L
		STOCK NO		770-5365	770-5365
8. COUPLING, VICTAULIC, 770		INCHES	2	4	4
		STOCK NO	770-1502	770-1504	770-1504
9. NIPPLE, VIC x THD		INCHES	2 x 4L	4 x 6L	4 x 6L
		STOCK NO	770-5391	770-5210	770-5210
10. NIPPLE, VIC x BEVELED		INCHES	2 x 6L	4 x 6L	4 x 6L
		STOCK NO	770-5392	770-5396	770-5396
11. TEE, WELD, STD WALL		INCHES	2 x 2 x 2	4 x 4 x 2	4 x 4 x 2
		STOCK NO	770-7859	770-7860	770-7860
12. METER BASE	CONCRETE BLOCK	INCHES	4 x 8 x 16	4 x 8 x 16	4 x 8 x 16
		STOCK NO	770-0498	770-0498	770-0498
	CONCRETE PAD	INCHES	4 x 18 x 18	6 x 30 x 30	6 x 36 x 36
13. NIPPLE, WELD x THD, SCH 40, FABRICATE		INCHES	2 x 3L	2 x 3L	2 x 3L
		STOCK NO	FABRICATE	FABRICATE	FABRICATE
14. PLUG, THREADED, CL 3000		INCHES	2	2	2
		STOCK NO	732-6130	732-6130	732-6130
15. METER VALVE, LOCKWING, INSULATED 175 PSIG		INCHES	2	2	2
		STOCK NO	770-8532	770-8532	770-8532
16. VALVE, WELDBALL, ANSI 150		INCHES	2	4	4
		STOCK NO	770-8700	770-8710	770-8710
17. THREAD-O-LET, 3,000 PSIG		INCHES	¼	¼	¼
		STOCK NO	770-8851	770-8851	770-8851
18. PETE'S PLUG		INCHES	–	–	–
		STOCK NO	770-6667	770-6667	770-6667
19. CORRUGATED PVC		INCHES	4	4	4
		STOCK NO	770-6430	770-6430	770-6430
20. STRAINER, 2" VERTICAL TEE, STYLE 351, THD, 175 PSIG, 100 MESH SCREEN		INCHES	2	2	2
		STOCK NO	770-7837	770-7837	770-7837



TYPICAL LARGE METER SET

SCALE: 1" = 1'- 0"

80-B, 250-B, 500-B,
AL-1400, AL-2300, AL-5000



DETAIL 1

SCALE: 1½" = 1'-0"

NOTES:

1. VENT ON REGULATOR SHOULD BE IN THE DOWNWARD POSITION TO PREVENT WATER ACCUMULATION OR NEED TO INSTALL A VENT ELBOW INSTALLED IN A DOWNWARD POSITION.
2. SUPPLEMNTAL RELIEF VALVE: IF A CL-31-IMRV OR CL-38-2IMRV REGULATOR IS USED, A SUPPLEMENTAL RELIEF VALVE IS ALSO REQUIRED. REFER TO THE GAS STANDARDS MANUAL SPECIFICATION 2.24 METER SET REGULATOR TABLES FOR INFORMATION ON SELECTING THE CORRECT RELIEF VALVE.

SUPERSEDES B-35209 SHT 2, DATED 2-28-94

NO	DATE	REVISION	BY	CKD
7	8-24-22	UPDATE RISER STOCK NUMBER	TJH	DRS
6	10-12-21	UPDATED THREADED PLUG	CGD	DRS
5	10-10-19	UPDATED BURY LINE NOTE. REMOVED SCREEN TEE DETAIL	CGD	DRS
4	8-20-18	ADD SUPPLEMENTAL RELIEF VALVE NOTE	TLB	DRS
3	8-6-14	STANDARDS UPDATE	JAJ	DRS
2	5-1-14	REMOVE 5000AL METER	CGD	DRS
1	2-23-11	ADDED VERTICAL STRAINER & CHANGED TO 'C' SIZE	WOC	TLB

DISTRIBUTION - GAS
METERING & REGULATION
STANDARD METER SET
TYPICAL LARGE DIAPHRAGM METER SETS

AVISTA CORP
SPOKANE, WASHINGTON

SCALE NONE	DATE 2-21-11	APPROVED David Howell
DSN BARRY	CKD TLB	DATE 2-22-11
DR WOC	NTD	SHT 2
CKD	NTD CL	OF C-35209

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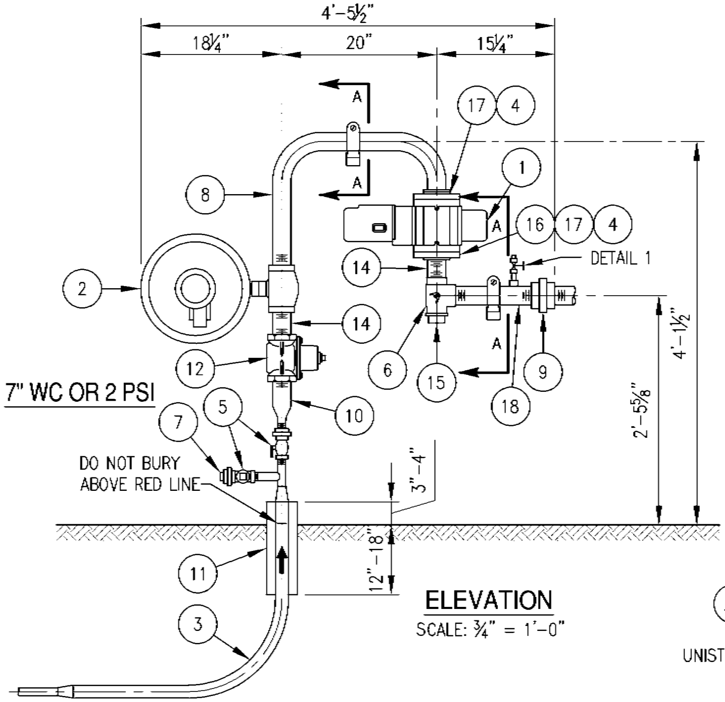
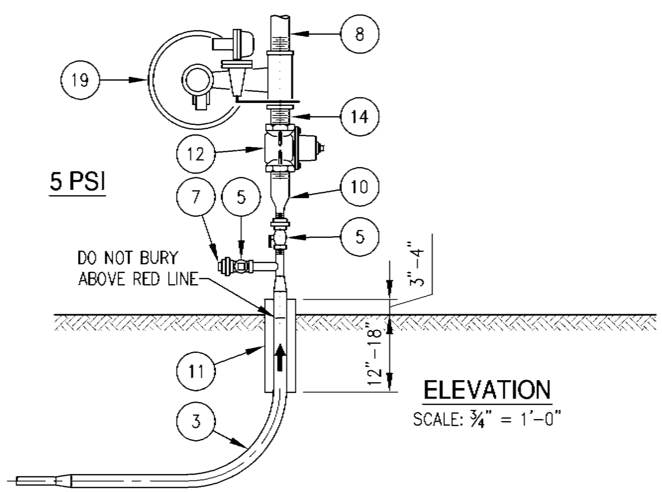


ELEVATION

SCALE: ¾" = 1'-0"



ELEVATION

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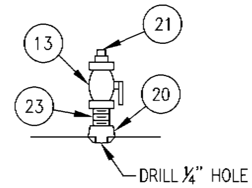
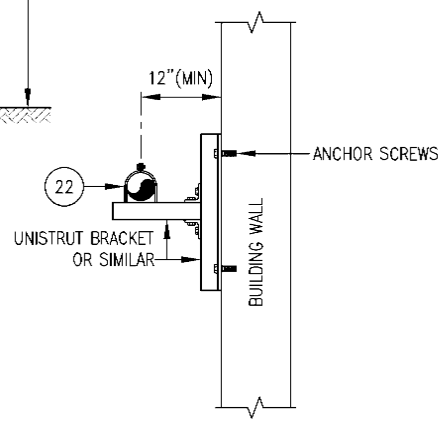


DETAIL 1

SCALE: NONE

(1) REQUIRED



WALL HANGER SECTION A-A

SCALE: NONE

(2) PREFERRED

(1) REQUIRED NEAR CUSTOMER TIE-IN POINT

MATERIAL LIST

ITEM	SIZE	QTY	STOCK NO	DESCRIPTION
1	2"	1	METER SHOP	ROTARY METER, 3500TC, 3000TC OR 2000TC
2	2"	1	METER SHOP	REGULATOR, CLASS "C" (REF: "REG CAP TABLES")
3	¾"	1	770-7222	SERVICE RISER W/ ¾" BYPASS
4	⅝"	8	770-0499	BOLT, 2" LONG, GRADE 8, YELLOW ZINC PLATED
5	¾"	2	770-8525	VALVE, MUELLER, 175 PSI, THD, INSULATED
6	2"	1	770-8830	3-WAY VALVE, DIVERTER, THD, 400 PSIG
7	¾"	1	732-6118	PLUG, THREADED, CL 3000
8	2"	1	770-4921	U-BEND, 2" NPT x 2" FLAT FACE FLANGE, ANSI 150
9	2"	1	770-8197	UNION, THD, MALL IRON, CL 150, INSULATED
10	2" x ¾"	1	770-5350	SWAGE, THD x THD, SCH 80
11	4"	2'	770-6430	CORRUGATED PVC
12	2"	1	770-7837	DRESSER TYPE 351 STRAINER, THD, 175 PSIG
13	¼"	1	770-1275	VALVE, BALL, THD, 600 PSIG
14	2"	2	732-5582	PIPE, NIPPLE, 4" LONG, THD x THD, SCH 40
15	2"	1	732-6130	PLUG, THREADED, CL 3000
16	2"	1	770-2335	FLANGE, THD, ANSI 150, FLAT FACED
17	2"	2	METER SHOP	GASKET, ANSI 150, TYPE E, FLAT FACED
18	2"	1	732-5586	PIPE, NIPPLE, 6" LONG, THD x THD, SCH 40
19	2"	1	METER SHOP	REGULATOR, CLASS "D" (REF: "REG CAP TABLES")
20	¼"	1	770-8851	THREAD-O-LET, CL 3000
21	¼"	1	770-6667	PETE'S PLUG, 1,000 PSIG
22	$\frac{1}{32}$"	1	770-3215	INSULATING MATERIAL
23	¼"	1	732-5400	NIPPLE, THD, 1½"L, SCH 80

CONSTRUCTION NOTES

MSA & PIPING	SUBJECT TO 90 PSI MIN. PRESSURE TEST PRIOR TO INSTALLATION OF REGULATORS, TEST W/SPRING GAGE FOR 1 HR MIN. SOAP TEST AT OPERATING PRESSURE AFTER GAS TURN ON.
PAINT	REMOVE ALL RUST AND SCALE, APPLY ONE COAT OF PRIMER AND TWO COATS OF GRAY METER ENAMEL.
BRACES	BRACES TO BE FABRICATED IN THE FIELD. IF UNABLE TO CONNECT BRACE TO BUILDING, USE A GROUND SUPPORT.
NOTES	CLEAN INTERNAL PIPE OF WELD SLAG PRIOR TO INSTALLATION OF METER.
LEVEL MTR	LEVEL METER TO WITHIN $\frac{1}{16}$" PER FOOT.
REG VENT	VENT ON REGULATOR SHOULD BE IN DOWNWARD POSITION TO PREVENT WATER ACCUMULATION OR A VENT ELBOW INSTALLED IN THE DOWNWARD POSITION.
SUPPLEMENTAL RELIEF VALVE	IF A CL-31-IMRV OR CL-38-2IMRV REGULATOR IS USED, A SUPPLEMENTAL RELIEF VALVE IS ALSO REQUIRED. REFER TO THE GAS STANDARDS MANUAL SPECIFICATION 2.24 METER SET REGULATOR TABLES FOR INFORMATION ON SELECTING THE CORRECT RELIEF VALVE.

NO	DATE	REVISION	BY	CKD
10	8-24-22	UPDATE RISER STOCK NUMBER	TJH	DRS
9	10-12-21	UPDATED THREADED PLUG	CGD	DRS
8	10-10-19	ADD U-BEND AND REVISED WALL BRACKET	CGD	DRS
7	8-31-18	ADD SUPPLEMENTAL RELIEF VALVE NOTE	TLB	DRS SRS
6	9-14-15	STANDARD REVISIONS	CGD	SRS
5	8-6-14	STANDARD REVISIONS	JAJ	DRS
4	10-12	STANDARD REVISIONS	DAG	SRS

DISTRIBUTION - GAS
STANDARD METER SET FOR
2000, 3000 AND 3500 ROTARY METERS
INTERMEDIATE DELIVERY PRESSURE: 7" WC, 2 OR 5 PSI

AVISTA CORP
SPOKANE, WASHINGTON

SCALE	DATE	APPROVED
AS SHOWN	11-23-92	3-03-93
DSN BURGER	CKD	DATE
DR PICKUP	NTD	SHT 1
CKD	NTD JW	OF 4

B-33325

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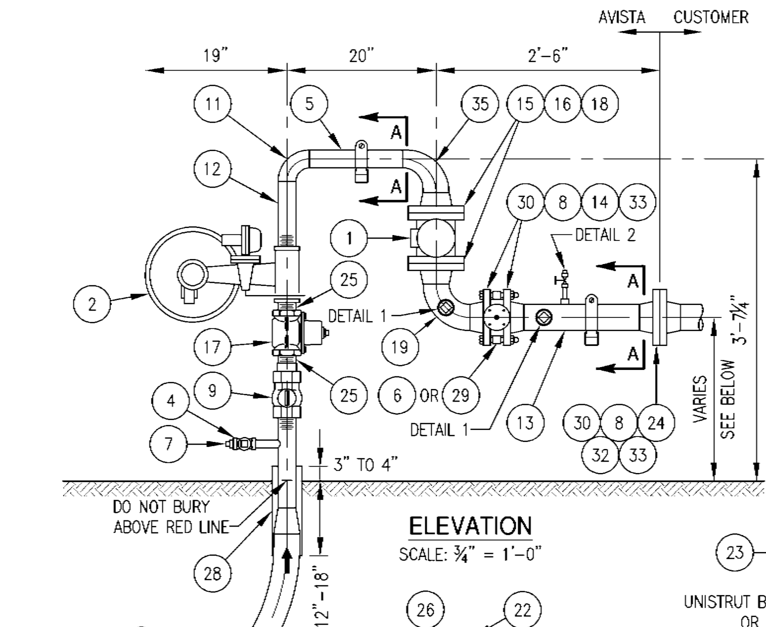
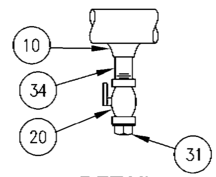
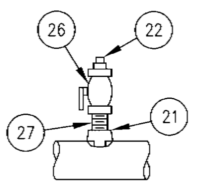


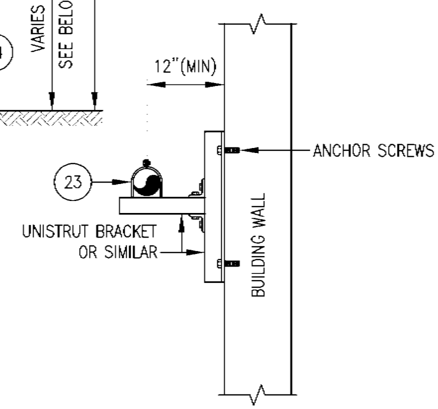
ELEVATION
SCALE: ¾" = 1'-0"



DETAIL 1
PLAN VIEW
SCALE: NONE
(2) REQUIRED



DETAIL 2
SCALE: NONE
(1) REQUIRED



WALL HANGER SECTION A-A
SCALE: NONE
(2) PREFERRED
(1) REQUIRED NEAR CUSTOMER TIE-IN POINT

MATERIAL LIST

ITEM	SIZE	QTY	STOCK NO	DESCRIPTION
1	3"	1	METER SHOP	ROTARY METER, 5000TC OR 7000TC
2	2"	1	METER SHOP	REGULATOR, CLASS "C" OR CLASS "D" (REF: "REG CAP TABLES")
3	2"	1	770-7230	SERVICE RISER W/ ¾" BYPASS
4	¾"	1	770-8525	VALVE, MUELLER, 175 PSI, THD, LOCKWING, INS
5	2"	1	770-6110	PIPE, STEEL, STD WALL, GR B
6	3"	1 OR 0	770-8745	BUTTERFLY VALVE, 175 PSI, NO HANDLE
7	¾"	1	732-6118	PLUG, THREADED, CL 3000
8	3"	1 OR 3	770-2481	GASKET, ANSI 150, TYPE "F"
9	2"	1	770-8532	VALVE, MUELLER, 175 PSIG, THD, LOCK WING, INS, WITH UNION
10	2"	2	770-8855	THREAD-O-LET, CL 3000
11	2"	1	770-2051	STEEL WELD ELBOW, 90 DEG, STD WALL, GR B
12	2"	1	770-6110	PIPE, STEEL, STD WALL, GR B, ONE END THREADED
13	3"	4'	770-6115	PIPE, STEEL, STD WALL, GR B
14	⅝"	4 OR 0	770-0523	BOLT, 5" LONG, GR 8, YELLOW ZINC PLATED
15	3"	2	770-2330	FLANGE, WELDNECK STD WALL, 150 ANSI, FLAT FACED
16	3"	2	METER SHOP	GASKET, ANSI 150, TYPE "E"
17	2"	1	770-7837	DRESSER, TYPE 351 PIPELINE STRAINER, THD, 175 PSIG
18	⅝"	8	770-0499	BOLT, 2" LONG, GR 8, YELLOW ZINC PLATED
19	3"	1	770-2053	STEEL WELD ELBOW, 90 DEG STD WALL, GR B
20	2"	2	770-8835	VALVE, BALL, 600 PSIG, THD, FULL PORT
21	¼"	1	770-8851	THREAD-O-LET, CL 3000
22	¼"	1	770-6667	PETE'S PLUG, 1,000 PSIG
23	1/32"	2	770-3215	INSULATING MATERIAL
24	3"	1	770-3264	INSULATING KIT, ANSI 150, GASKET
25	2"	2	732-5274	NIPPLE, CLOSE, THD, SCH 40
26	¼"	1	770-1275	VALVE, BALL, THD, 600 PSIG
27	¼"	1	732-5400	NIPPLE, THD, 1½"L, SCH 80
28	4"	2'	770-6430	CORRUGATED PVC
29	3"	1 OR 0	770-8705	VALVE, WELDBALL, ANSI 150
30	3"	2 OR 4	770-2307	FLANGE, WELDNECK, RAISED FACE, ANSI 150
31	2"	2	732-6130	PLUG, THREADED, CL 3000
32	⅝"	4	770-0520	BOLT, 3½"L, GR 8, YELLOW ZINC PLATED
33	⅝"	4 OR 8	770-5450	NUT, GR 8, YELLOW ZINC PLATED
34	2"	2	SHOP	NIPPLE, 2½"L, THD, SCH 80 (CUT IN HALF)
35	3"x 2"	1	770-2024	STEEL WELD ELBOW, REDUCING, 90 DEG, STD WALL, GR B

DIMENSIONS
OUTLET PIPING TO GRADE: 7000 = 22.5"
5000 = 25.5"

NOTE:
SEE A-34175 FOR GROUND PIPE SUPPORT STANDARDS

CONSTRUCTION NOTES

MSA & PIPING	SUBJECT TO 90 PSI MIN. PRESSURE TEST PRIOR TO INSTALLATION OF REGULATORS, TEST W/SPRING GAGE FOR 1 HR MIN. SOAP TEST AT OPERATING PRESSURE AFTER GAS TURN ON.
PAINT	REMOVE ALL RUST AND SCALE, APPLY ONE COAT OF PRIMER AND TWO COATS OF GRAY METER ENAMEL.
BRACES	BRACES TO BE FABRICATED IN THE FIELD. IF UNABLE TO CONNECT BRACE TO BUILDING, USE A GROUND SUPPORT.
NOTES	CLEAN INTERNAL PIPE OF WELD SLAG PRIOR TO INSTALLATION OF METER.
LEVEL MTR	LEVEL METER TO WITHIN 1/16" PER FOOT.
REG VENT	VENT ON REGULATOR SHOULD BE IN DOWNWARD POSITION TO PREVENT WATER ACCUMULATION OR A VENT ELBOW INSTALLED IN THE DOWNWARD POSITION.
SUPPLEMENTAL RELIEF VALVE	IF A CL-31-IMRV OR CL-38-2IMRV REGULATOR IS USED, A SUPPLEMENTAL RELIEF VALVE IS ALSO REQUIRED. REFER TO THE GAS STANDARDS MANUAL SPECIFICATION 2.24 METER SET REGULATOR TABLES FOR INFORMATION ON SELECTING THE CORRECT RELIEF VALVE.

NO	DATE	REVISION	BY	CKD
12	8-24-22	UPDATE RISER STOCK NUMBER	TJH	DRS
11	10-12-21	UPDATED THREADED PLUG	CGD	DRS
10	10-10-19	ADDED PROVER PORT AND REVISED WALL HANGER	CGD	DRS
9	8-31-18	ADD SUPPLEMENTAL RELIEF VALVE NOTE	TLB	DRS/SRS
8	9-14-15	STANDARDS UPDATE	CGD	SRS
7	8-6-14	STANDARDS UPDATE	JAJ	DRS
6	10-12	STANDARDS REVISION	DAG	SRS

DISTRIBUTION - GAS
STANDARD METER SET
5000 AND 7000 ROTARY METERS
INTERMEDIATE DELIVERY PRESSURE: 7" WC, 2 OR 5 PSI
AVISTA CORP
SPOKANE, WASHINGTON

AS SHOWN	1-08-93	APPROVED	
SCALE	DATE	3-03-93	
DSN BURGER	CKD		
DR PICKUP	NTD	SHT 2	DATE
CKD	NTD JW	OF 4	B-33325

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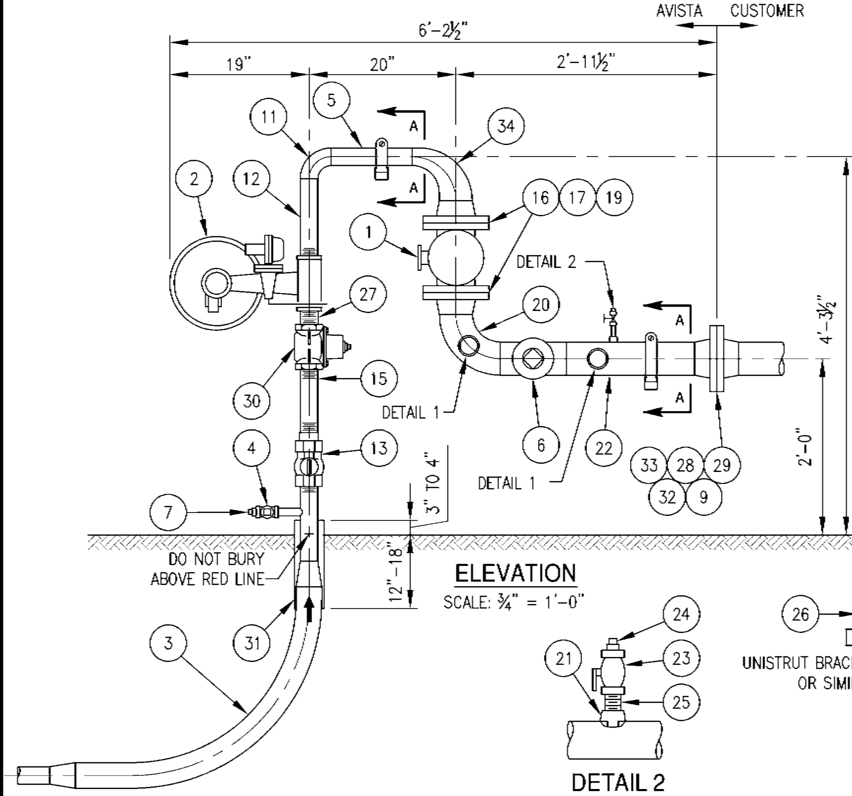
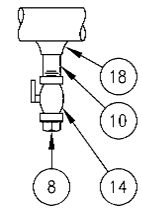


ELEVATION

SCALE: ¾" = 1'-0"

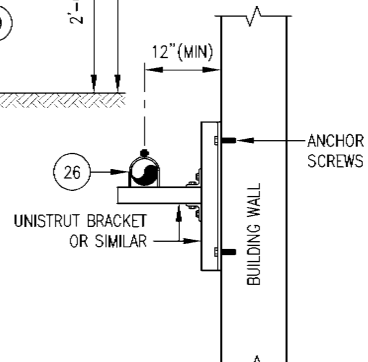


DETAIL 1

PLAN VIEW
SCALE: NONE
(2) REQUIRED

DETAIL 2

SCALE: NONE
(1) REQUIRED



WALL HANGER SECTION A-A

SCALE: NONE
(2) PREFERRED
(1) REQUIRED NEAR CUSTOMER TIE-IN POINT

NOTE:
SEE A-34175 FOR GROUND PIPE SUPPORT STANDARDS

MATERIAL LIST

ITEM	SIZE	QTY	STOCK NO	DESCRIPTION
1	4"	1	METER SHOP	ROTARY METER, 11000
2	2"	1 OR 0	METER SHOP	REGULATOR, CLASS "C" OR CLASS "D" (REF: "REG CAPACITY TABLES")
3	2"	1	770-7230	SERVICE RISER W/ ¾" BYPASS, NON-CP
4	¾"	1	770-8525	VALVE, MUELLER, 175 PSI, THD, LOCKWING, INS
5	2"	1'	770-6110	PIPE, STEEL, STD WALL, GR B
6	4"	1	770-8710	VALVE, WELDBALL, ANSI 150
7	¾"	1	732-6118	PLUG, THD, CL 3000
8	2"	2	732-6130	PLUG, THD, CL 3000
9	⅝"	8	770-5450	NUT, GR 8, YELLOW ZINC PLATED
10	2"	2	SHOP	NIPPLE, 2½"L, THD, SCH 80 (CUT IN HALF)
11	2"	1	770-2051	STEEL WELD ELBOW, 90 DEG, STD WALL, GR B
12	2"	1'	770-6110	PIPE, STEEL, STD WALL, GR B, ONE END THREADED
13	2"	1	770-8532	VALVE, MUELLER, 175 PSIG, THD, LOCKWING, INS, WITH UNION
14	2"	2	770-8835	VALVE, BALL, 600 PSIG, THD, FULL PORT
15	2"	1	732-5588	NIPPLE, 8" LONG, THD, SCH 40
16	4"	2	770-2331	FLANGE, WELDNECK, ANSI 150, FLAT FACED
17	4"	2	METER SHOP	GASKET, ANSI 150, TYPE "E"
18	2"	2	770-8850	WELD-O-LET, CL 3000
19	⅝"	16	770-0499	BOLT, 2"L, GR 8, YELLOW ZINC PLATED
20	4"	1	770-2057	STEEL WELD ELBOW, 90 DEG, STD WALL, GR B
21	¼"	1	770-8851	THREAD-O-LET, CL 3000
22	4"	3'	770-6120	PIPE, STEEL, STD WALL, GRD B
23	¼"	1	770-1275	VALVE, BALL, THD, 600 PSIG
24	¼"	1	770-6667	PETE'S PLUG, 1,000 PSIG
25	¼"	1	732-5400	NIPPLE, THD, 1½"L, SCH 80
26	1/32"	2	770-3215	INSULATING MATERIAL
27	2"	1	732-5274	NIPPLE, CLOSE, THD, SCH 40
28	4"	1	770-2534	GASKET, FLANGE, ANSI 150, TYPE F
29	4"	1	770-3266	INSULATING KIT, ANSI 150
30	2"	1	770-7837	DRESSER, TYPE 351 PIPELINE STRAINER, THD, 175 PSIG
31	4"	2'	770-6430	CORRUGATED PVC
32	⅝"	8	770-0520	BOLT, 3½"L, GR 8, YELLOW ZINC PLATED
33	4"	2	770-2308	FLANGE, WELDNECK, RAISED FACE, ANSI 150
34	4"x 2"	1	770-2025	STEEL WELD ELBOW, REDUCING, 90 DEG, STD WALL, GR B

CONSTRUCTION NOTES

INLET HEAD & OUTLET	SUBJECT TO 90 PSI MIN. PRESSURE TEST PRIOR TO INSTALLATION OF REGULATORS, TEST W/SPRING GAGE FOR 1 HR MIN. SOAP TEST AT OPERATING PRESSURE AFTER GAS TURN ON.
PAINT	REMOVE ALL RUST AND SCALE, APPLY ONE COAT OF PRIMER AND TWO COATS OF GRAY METER ENAMEL.
BRACES	BRACES TO BE FABRICATED IN THE FIELD. IF UNABLE TO CONNECT BRACE TO BUILDING, USE A GROUND SUPPORT.
NOTES	CLEAN INTERNAL PIPE OF WELD SLAG PRIOR TO INSTALLATION OF METER.
LEVEL MTR	LEVEL METER TO WITHIN 1/16" PER FOOT.
REG VENT	VENT ON REGULATOR SHOULD BE IN DOWNWARD POSITION TO PREVENT WATER ACCUMULATION OR A VENT ELBOW INSTALLED IN THE DOWNWARD POSITION.
SUPPLEMENTAL RELIEF VALVE	IF A CL-31-IMRV OR CL-38-2IMRV REGULATOR IS USED, A SUPPLEMENTAL RELIEF VALVE IS ALSO REQUIRED. REFER TO THE GAS STANDARDS MANUAL SPECIFICATION 2.24 METER SET REGULATOR TABLES FOR INFORMATION ON SELECTING THE CORRECT RELIEF VALVE.

NO	DATE	REVISION	BY	CKD
12	8-24-22	UPDATE RISER STOCK NUMBER	TJH	DRS
11	10-12-21	UPDATED THREADED PLUG	CGD	DRS
10	10-10-19	ADDED PROVER PORT AND REVISED WALL HANGER	CGD	DRS
9	8-31-18	STANDARDS UPDATE	TLB	DRS SRS
8	9-14-15	STANDARDS UPDATE	CGD	SRS
7	8-6-14	STANDARDS UPDATE	JAJ	DRS

DISTRIBUTION - GAS
STANDARD METER SET FOR
11000 ROTARY METER
INTERMEDIATE DELIVERY PRESSURE: 7" WC, 2 OR 5 PSI

AVISTA CORP
SPOKANE, WASHINGTON

AS SHOWN (SCALE)	3-26-93 (DATE)	APPROVED
DSN BURGER	CKD	3-29-93 (DATE)
DR PICKUP	NTD	SHT 4
CKD	NTD JW	OF 4 — B-33325

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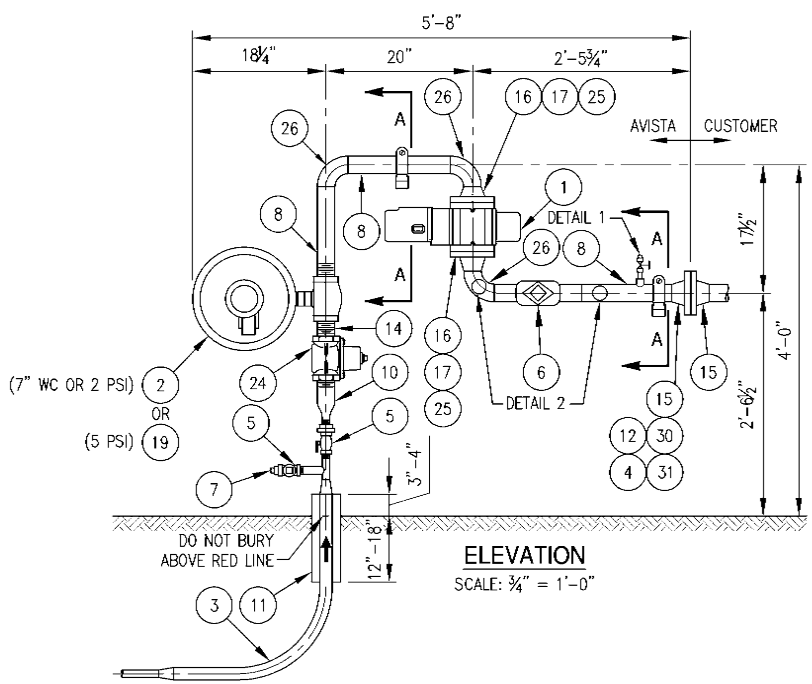
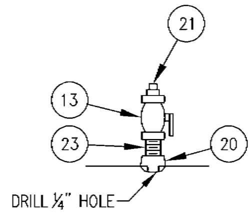
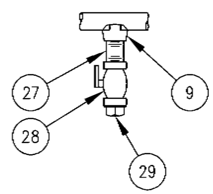


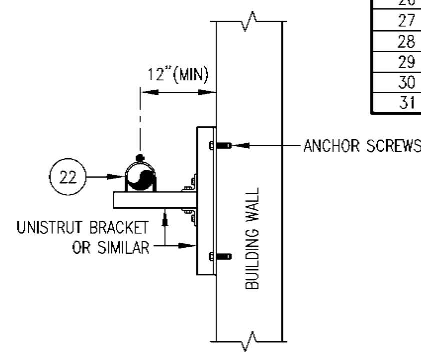
ELEVATION
SCALE: ¾" = 1'-0"



DETAIL 1
SCALE: NONE
(1) REQUIRED



DETAIL 2
SCALE: NONE
(2) REQUIRED



WALL HANGER SECTION A-A
SCALE: NONE
(2) PREFERRED
(1) REQUIRED NEAR CUSTOMER TIE-IN POINT

MATERIAL LIST

ITEM	SIZE	QTY	STOCK NO	DESCRIPTION
1	2"	1	METER SHOP	ROTARY METER, 3500TC, 3000TC OR 2000TC
2	2"	1	METER SHOP	REGULATOR, CLASS "C" (REF: "REG CAP TABLES")
3	¾"	1	770-7220	SERVICE RISER W/ ¾" BYPASS
4	⅝"	4	770-5450	NUT, ASTM A194 GRADE 2H, ZINC PLATED
5	¾"	2	770-8525	VALVE, MUELLER, 175 PSI, THD, INSULATED
6	2"	1	770-8700	VALVE, BALL, ANSI 150, WELD ENDS
7	¾"	1	732-6118	PLUG, THD, CL 3000
8	2"	4'	770-6110	STEEL PIPE, STD WALL, WPB
9	2"	2	770-8855	THREAD-O-LET, CL 3000
10	2" x ¾"	1	770-5350	SWAGE, THD x THD, SCH 80
11	4"	2'	770-6430	CORRUGATED PVC
12	⅝"	4	770-0515	BOLT, 3¼"L, ASTM A307 GR B, ZINC PLATED
13	¼"	1	770-1275	VALVE, BALL, THD, 600 PSIG
14	2"	1	732-5582	PIPE, NIPPLE, 4"L, THD x THD, SCH 40
15	2"	2	770-2306	FLANGE, WELD NECK, ANSI 150, RAISED FACE
16	2"	2	770-2329	FLANGE, WELD NECK, ANSI 150, FLAT FACE
17	2"	2	METER SHOP	GASKET, ANSI 150, TYPE E, FLAT FACED
18	2"	1	732-5586	PIPE, NIPPLE, 6" LONG, THD x THD, SCH 40
19	2"	1	METER SHOP	REGULATOR, CLASS "D" (REF: "REG CAP TABLES")
20	¼"	1	770-8851	THREAD-O-LET, CL 3000
21	¼"	1	770-6667	PETE'S PLUG, 1,000 PSIG
22	$\frac{1}{32}$"	1'	770-3215	INSULATING MATERIAL
23	¼"	1	732-5400	NIPPLE, THD, 1½"L, SCH 80
24	2"	1	770-7837	DRESSER, TYPE 351 PIPELINE STRAINER, THD, 175 PSIG
25	⅝"	8	770-0499	BOLT, 2" LONG, GRADE 8, YELLOW ZINC PLATED
26	2"	3	770-2051	STEEL ELBOW, 90 DEG, WELD, STD WALL, WPB
27	2"	1	SHOP	NIPPLE, 2½"L, THD, SCH 80 (CUT IN HALF)
28	2"	2	770-8835	VALVE, BALL, 600 PSIG, THD, FULL PORT
29	2"	2	732-6130	PLUG, THD, CL 3000
30	2"	1	770-2533	GASKET, ANSI 150, TYPE F
31	2"	1	770-3261	FLANGE BOLT INSULATING KIT, ANSI 150

CONSTRUCTION NOTES

MSA & PIPING	SUBJECT TO 90 PSI (MIN) PRESSURE TEST PRIOR TO INSTALLATION OF REGULATORS. TEST WITH GAUGE FOR 1 HR MIN. SOAP TEST AT OPERATING PRESSURE AFTER GAS TURN ON.
PAINT	REMOVE ALL RUST AND SCALE, APPLY ONE COAT OF PRIMER AND TWO COATS OF GRAY METER ENAMEL.
BRACES	BRACES TO BE FABRICATED IN THE FIELD. IF UNABLE TO CONNECT BRACE TO BUILDING, USE A GROUND SUPPORT.
NOTES	CLEAN INTERNAL PIPE OF WELD SLAG PRIOR TO INSTALLATION OF METER.
LEVEL MTR	LEVEL METER TO WITHIN $\frac{1}{16}$" PER FOOT.
REG VENT	VENT ON REGULATOR SHOULD BE IN DOWNWARD POSITION OR A VENT ELBOW INSTALLED IN THE DOWNWARD POSITION TO PREVENT WATER ACCUMULATION.
SUPPLEMENTAL RELIEF VALVE	IF A CL-31-IMRV OR CL-38-2IMRV REGULATOR IS USED, A SUPPLEMENTAL RELIEF VALVE IS ALSO REQUIRED. REFER TO THE GAS STANDARDS MANUAL SPECIFICATION 2.24 METER SET REGULATOR TABLES FOR INFORMATION ON SELECTING THE CORRECT RELIEF VALVE.

NO	DATE	REVISION	BY	CKD	AS BUILT
4	8-24-22	UPDATE RISER STOCK NUMBER	TJH	DRS	[redacted]
3	10-12-21	UPDATED THREADED PLUG	CGD	DRS	[redacted]
2	10-10-19	UPDATE WALL HANGER DETAIL	CGD	DRS	[redacted]

DISTRIBUTION - GAS
STANDARD METER SET FOR WELDED
2000, 3000 AND 3500 ROTARY METERS
INTERMEDIATE DELIVERY PRESSURE: 7" WC, 2 OR 5 PSI
AVISTA CORP
SPOKANE, WASHINGTON

AS SHOWN (SCALE)	6-22-16 (DATE)	APPROVED: [signature] 8-23-16 (DATE)
DSN SMITH	CKD DRS	SHT 1
DR WOC	NTD	OF 1 — B-38205
CKD JAF	NTD CL	

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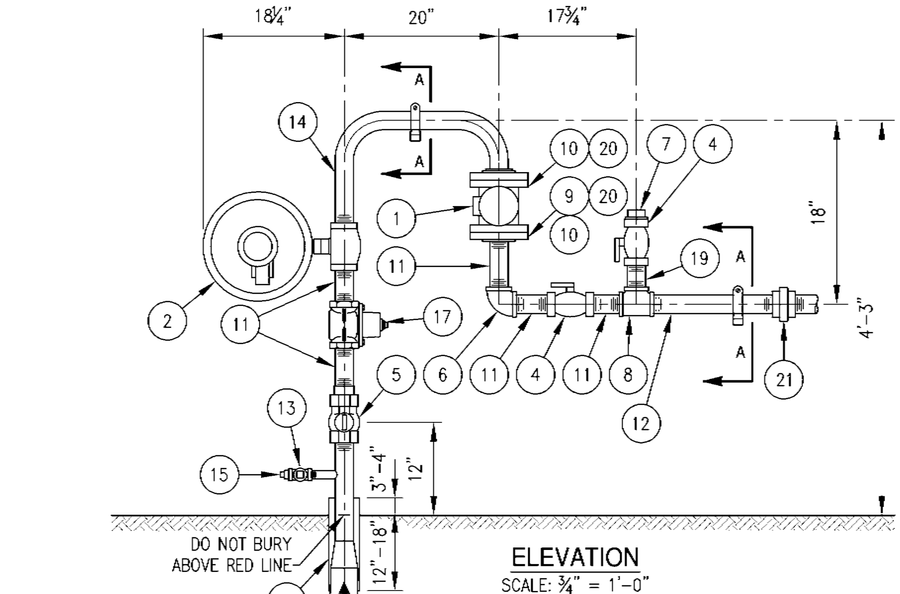
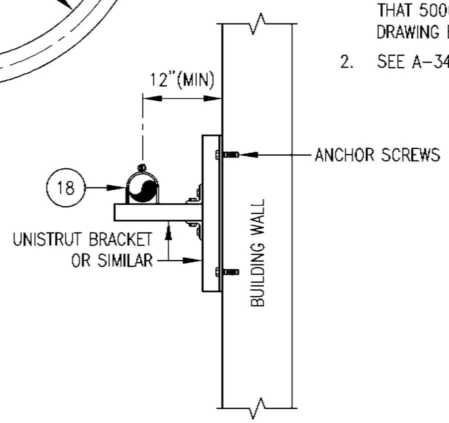


ELEVATION

SCALE: ¾" = 1'-0"

NOTES:

1. IT IS PREFERRED WHEN RESOURCES ARE AVALIABLE THAT 5000 AND 7000 ROTARY SETS BE WELDED PER DRAWING B-33325, SHEET 2.
2. SEE A-34175 FOR GROUND PIPE SUPPORT STANDARDS.



WALL HANGER SECTION A-A

SCALE: NONE
(2) PREFERRED
(1) REQUIRED NEAR CUSTOMER TIE-IN POINT

MATERIAL LIST

ITEM	SIZE	QTY	STOCK NO	DESCRIPTION
1	3"	1	METER SHOP	ROTARY METER, 5000 OR 7000
2	2"	1	METER SHOP	REGULATOR, CLASS "C" OR CLASS "D" (REF: "REG CAP TABLES")
3	2"	1	770-7230	SERVICE RISER W/ ¾" BYPASS, NON-CP
4	2"	2	770-8835	VALVE, BALL, 600 PSIG, THD, FULL PORT
5	2"	1	770-8532	VALVE, MUELLER, 175 PSIG, THD, LOCKWING, INSULATED, WITH UNION
6	2"	2	732-1740	STEEL ELBOW, 90 DEG, THD, MALLEABLE IRON, CLASS 150
7	2"	1	732-6130	PLUG, THREADED, CL 3000
8	2" x 2" x 2"	1	732-7729	TEE, THD, CL 150
9	3" x 2"	1	770-2327	FLANGE, THD, REDUCING OUTLET, ANSI 150, FLAT FACED
10	3"	2	METER SHOP	GASKET, ANSI 150, NEOPRENE, TYPE "E"
11	2"	5	732-5586	NIPPLE, 2" x 6"L, THD, IRON, SCH 40
12	2"	1'	770-6110	PIPE, STEEL, STD WALL, GR B, THD x THD, CUT TO FIT
13	¾"	1	770-8525	VALVE, METER, 175 PSI, THD, LOCKWING, INS
14	2"	1	770-4922	U-BEND, 2" NPT x 3" FLAT FACE FLANGE, ANSI 150
15	¾"	1	732-6118	PLUG, THREADED, CL 3000
16	4"	2'	770-6430	CORRUGATED PVC
17	2"	1	770-7837	DRESSER, TYPE 351 STRAINER, THD, 175 PSIG
18	1/32"	1	770-3215	INSULATING MATERIAL
19	2"	1	732-5580	NIPPLE, 2" x 3"L, THD, IRON, SCH 40
20	⅝"	8	770-0499	BOLT, 2"L, GRADE 8, YELLOW ZINC PLATED
21	2"	1	770-8197	UNION, THD, MALL IRON, CL 150, INSULATED

CONSTRUCTION NOTES

MSA & PIPING	SUBJECT TO 90 PSI MIN PRESSURE TEST PRIOR TO INSTALLATION OF REGULATORS, TEST W/SPRING GAGE FOR 1 HR MIN. SOAP TEST AT OPERATING PRESSURE AFTER GAS TURN-ON.
PAINT	REMOVE ALL RUST AND SCALE, APPLY ONE COAT OF PRIMER AND TWO COATS OF GRAY METER ENAMEL.
BRACES	BRACES TO BE FABRICATED IN THE FIELD. IF UNABLE TO CONNECT BRACE TO BUILDING, USE A GROUND SUPPORT.
NOTES	CLEAN INTERNAL PIPE OF WELD SLAG PRIOR TO INSTALLATION OF METER.
	DO NOT USE GREASE ON THE ROTARY METER FLANGE OR GASKET.
LEVEL MTR	LEVEL METER TO WITHIN 1/16" PER FOOT.
REG VENT	VENT ON REGULATOR SHOULD BE IN DOWNWARD POSITION TO PREVENT WATER ACCUMULATION OR A VENT ELBOW INSTALLED IN THE DOWNWARD POSITION.
SUPPLEMENTAL RELIEF VALVE	IF A CL-31-IMRV OR CL-38-2IMRV REGULATOR IS USED, A SUPPLEMENTAL RELIEF VALVE IS ALSO REQUIRED. REFER TO THE GAS STANDARDS MANUAL SPECIFICATION 2.24 METER SET REGULATOR TABLES FOR INFORMATION ON SELECTING THE CORRECT RELIEF VALVE.

NO	DATE	REVISION	BY	CKD
10	8-24-22	UPDATE RISER STOCK NUMBER	TJH	DRS
9	10-12-21	UPDATED THREADED PLUG	CGD	DRS
8	10-10-19	ADD U BEND AND REVISED WALL HANGER	CGD	DRS
7	8-20-18	STANDARDS REVISION	TLB	DRS/SRS
6	9-14-15	STANDARDS REVISION	CGD	SRS
5	8-6-14	STANDARDS REVISION	JAJ	DRS
4	09-13	STANDARDS REVISION	TJH	TJH

DISTRIBUTION - GAS
STANDARD METER SET
THREADED 5000 AND 7000 ROTARY METERS
DELIVERY PRESSURE: 7" WC, 2 PSI OR 5 PSIG

AVISTA CORP
SPOKANE, WASHINGTON

AS SHOWN (SCALE)	8-15-01 (DATE)	APPROVED
DSN BURGER	CKD	10-11-01 (DATE)
DR JEWELL	MTD	SHT 1
CKD	MTD JW	OF 1 B-35785

AUTOCAD DWG

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METER SET LOCATION MAP

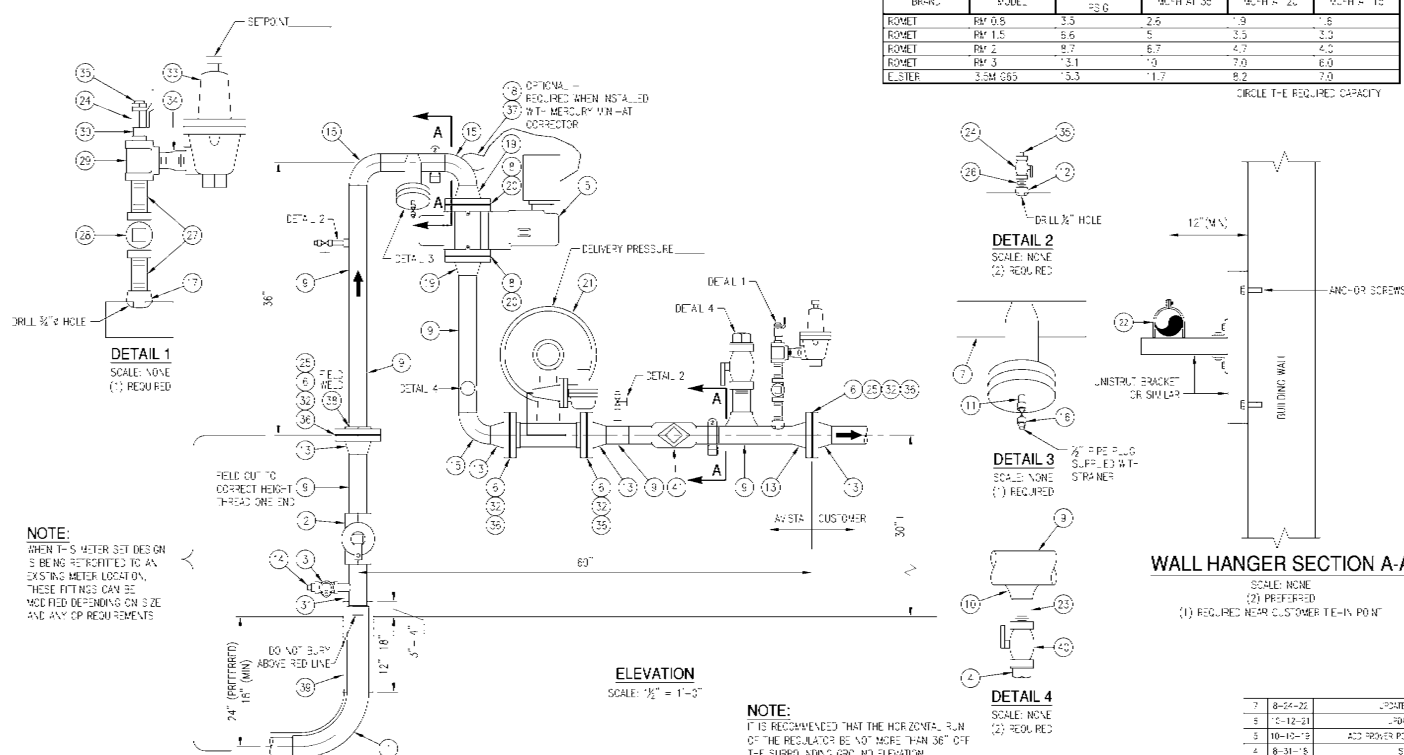
SCALE: NONE

VICINITY MAP

SCALE: NONE

ROTARY METER CAPACITY (MAX)---2" THROATS					
BRAND	MODEL	MCFH AT 50 PSIG	MCFH AT 35	MCFH AT 20	MCFH AT 15
ROMET	RM 0.8	3.5	2.6	1.9	1.6
ROMET	RM 1.5	6.6	5	3.5	3.0
ROMET	RM 2	8.7	6.7	4.7	4.0
ROMET	RM 3	13.1	10	7.0	6.0
ELSTER	3.5M G65	15.3	11.7	8.2	7.0

CIRCLE THE REQUIRED CAPACITY



NOTE:
WHEN THIS METER SET DESIGN IS BEING RETROFITTED TO AN EXISTING METER LOCATION, THESE FITTINGS CAN BE MODIFIED DEPENDING ON SIZE AND ANY CP REQUIREMENTS

NOTE:
IT IS RECOMMENDED THAT THE HORIZONTAL RUN OF THE REGULATOR BE NOT MORE THAN 36" OFF THE SURROUNDING GROUND ELEVATION.

MATERIAL LIST				
ITEM	SIZE	QTY	STOCK NO	DESCRIPTION
1	2"	1	770-7230	ANODELESS RISER WITH 3/4" BYPASS
2	2"	1	770-8592	METER VALVE, LOCKWING, NON-INSULATED, 175 PSIG
3	3/4"	1	770-8560	METER VALVE, LOCKWING, INSULATED, 175 PSIG
4	2"	2	732-6130	PLUG, THD, CL 3000
5	2"	1	METER SHOP	ROTARY METER, TC, W/PRESSURE CORRECTING HEAD
6	5/8"	16	770-0520	BOLT, 3 1/2"L, GR 8, YELLOW ZINC
7	2"	1	770-7639	STRAINER, WELD ENDS, ANSI 150
8	5/8"	8	770-0500	BOLT, 2 1/2"L, GR 8, YELLOW ZINC
9	2"	12'	770-6110	PIPE, BARE, STD WALL, GR B
10	2"	2	770-8650	WELD-O-LET, CL 3000
11	1/2"	1	732-5260	NIPPLE, 2" LONG, THD, SCH 80
12	1/4"	2	770-8651	THREAD-O-LET, CL 3000
13	2"	5	770-2306	WELD NECK FLANGE, RAISED FACE, ANSI 150
14	3/4"	1	732-6118	PLUG, THD, CL 3000
15	2"	3	770-2051	ELBOW, 90 DEG, STD WALL, GR B, LONG RADIUS, WELD ENDS
16	1/2"	1	770-1282	VALVE, BALL, THD, 600 PSIG, WITH HANDLE
17	3/4"	1	770-8653	THREAD-O-LET, CL 3000
18	1"	1	REQUISITION	THERMAL WELL, 1" NPT x 3/4" FPT, 4" LENGTH, 150 CLASS
19	2"	2	770-2329	FLANGE, FLAT FACE, WELD NECK, ANSI 150
20	2"	2	METER SHOP	GASKET, FLANGE, TYPE E, ANSI 150
21	2"	1	METER SHOP	AVISTA CLASS D REGULATOR, FLANGED
22	1/16"	2	770-3215	INSULATING MATERIAL
23	2"	2	SHOP	NIPPLE, 2" x 2 1/2"L, THD, SCH 80 (CUT IN HALF)
24	1/4"	3	770-1275	VALVE, BALL, THD, 600 PSIG
25	2"	2	770-3261	INSULATING KIT, ANSI 150
26	1/4"	2	732-5400	NIPPLE, THD, 1 1/2"L, SCH 80
27	3/4"	2	732-5446	NIPPLE, THD, 3"L, SCH 40
28	3/4"	1	770-1285	VALVE, BALL, THD, 600 PSIG, WITH HANDLE
29	3/4"	1	732-7690	TEE, THD, CL 150
30	3/4"x 1/4"	1	732-0525	BUSHING, REDUCING, THD, CL 150
31	#12	AS REQ'D	263-1002	WIRE TRACER, #12 SOLID COPPER, YELLOW
32	5/8"	16	770-5450	NUT, GR 8, YELLOW ZINC
33	1"	1	METER SHOP	FISHER 289-- REGULATOR, __________ PSIG SPRING
34	1"x 3/4"	1	770-5325	NIPPLE SWAGE, THD, SCH 40
35	1/4"	3	770-6667	PETE'S PLUG TEST PORT, 1,000 PSIG
36	2"	4	770-2533	GASKET, FLANGE, TYPE F, ANSI 150
37	1"	1	REQUISITION	ELBOW-O-LET, CL 3000
38	2"	1	REQUISITION	FLANGE, SLIP-ON, RAISED FACE, ANSI 150
39	4"	2'	770-6430	CORRUGATED PVC
40	2"	2	770-8635	VALVE, BALL, 600 PSIG, THD, FULL PORT
41	2"	1	770-8700	VALVE, BALL, WELD, ANSI 150

CUSTOMER AND EQUIPMENT NOTES

- *PRESSURE TEST THE MSA AT 90 PSIG MIN (100 PSIG MAX) FOR 1 HOUR MIN USING A SPRING GAUGE. PRESSURE TEST PRIOR TO INSTALLING THE METER AND REGULATOR.
- *THIS METER SET IS TO BE USED WITH ANY AVISTA APPROVED CLASS D REGULATORS.
- *REMOVE ALL RUST AND SCALE, APPLY ONE COAT OF PRIMER AND TWO COATS OF GREY METER ENAMEL PAINT.
- *CHECK AND CLEAN STRAINER AFTER FIRST 48 HOURS OF SERVICE, AND AGAIN AFTER 6 MONTHS OF SERVICE.
- *INLET AND METER SET VALVES SHALL MEET OR EXCEED METER SET MAOP
- *ALL WORK SHALL BE DONE IN ACCORDANCE WITH AVISTA STANDARDS AND SPECIFICATIONS
- *NO FIELD CHANGES ARE TO BE MADE WITHOUT THE APPROVAL OF GAS ENGINEERING.
- *INSTALL ALL VALVES SO THAT THE VALVE STEMS ARE IN A HORIZONTAL POSITION.
- *INSTALL LOCKING DEVICES ON ALL VALVES THAT DID NOT COME WITH A LOCKING DEVICE.
- *TERMINATE TRACER WIRE BELOW THE METER VALVE, USING A HALF-HITCH KNOT. DO NOT TAPE TRACER TO RISER
- *VENT ON THE REGULATOR SHOULD EITHER VENT DOWNWARD TO PREVENT WATER ACCUMULATION OR BE INSTALLED WITH A VENT ELBOW.
- *BRACES OR METER SUPPORTS SHALL BE FABRICATED IN THE FIELD.
- *LEVEL ROTARY METER TO WITHIN 1/16" PER FOOT.
- *CLEAN INTERNAL PIPE OF WELD SLAG PRIOR TO INSTALLATION OF THE METER.
- *INSTALL THERMAL WELL IN A HORIZONTAL LEVEL POSITION TO REDUCE WATER ACCUMULATION.
- *CONSULT GAS ENGINEERING FOR REGULATOR AND RELIEF SET PRESSURES.
- *SUPPLEMENTAL RELIEF VALVE: IF A CL-31-IMRV OR CL-38-2 MRV REGULATOR IS USED, A SUPPLEMENTAL RELIEF VALVE IS ALSO REQUIRED. REFER TO THE GAS STANDARDS MANUAL SPECIFICATION 2.24 METER SET REGULATOR TABLES FOR INFORMATION ON SELECTING THE CORRECT RELIEF VALVE.

CUSTOMER AND EQUIPMENT NOTES

DELIVERY PRESSURE TO CUSTOMER__________PSIG
CUSTOMER LOAD__________MCFH
CUSTOMER FUTURE LOAD__________MCFH
AVISTA DISTRIBUTION SYSTEM PRESSURE__________PSIG
MAOP OF AVISTA DIST SYSTEM__________PSIG
METER SIZE TO BE USED__________
METER CAPACITY__________MCFH @__________PSIG
REGULATOR CAPACITY__________MCFH @__________PSIG

METER SET #__________

NO	DATE	REVISION	BY	CKD
7	8-24-22	UPDATE RISER STOCK NUMBER	TJH	BRS
6	10-12-21	UPDATED THREADED PLUG	CCD	BRS
5	10-10-19	ADD PROVER PORT AND REVISED WALL BRACKET	CCD	BRS
4	8-31-18	STANDARDS UPDATE	TJB	BRS/SRS
3	9-14-15	STANDARDS UPDATE	CCD	SRS
2	10-25-12	STANDARDS UPDATE	DAS	SRS
1	08-23-11	ITEM 15 STOCK NUMBER CHANGE	TJH	RKB

DISTRIBUTION - GAS
CODE 3 - 2" STANDARD METER SET
PLAN, ELEV, DETAILS

AVISTA CORP
SPOKANE, WASHINGTON

NOTED — SCALE
11-02-10 — DATE
DESIGN McFADDEN CHECKED ______
DRAWN DAS NOTED ______
CHECKED BRS NOTED ______

APPROVED David Howell
8-18-10
DATE
SHT 1 OF 1 E-37197

AUTOCAD DWG

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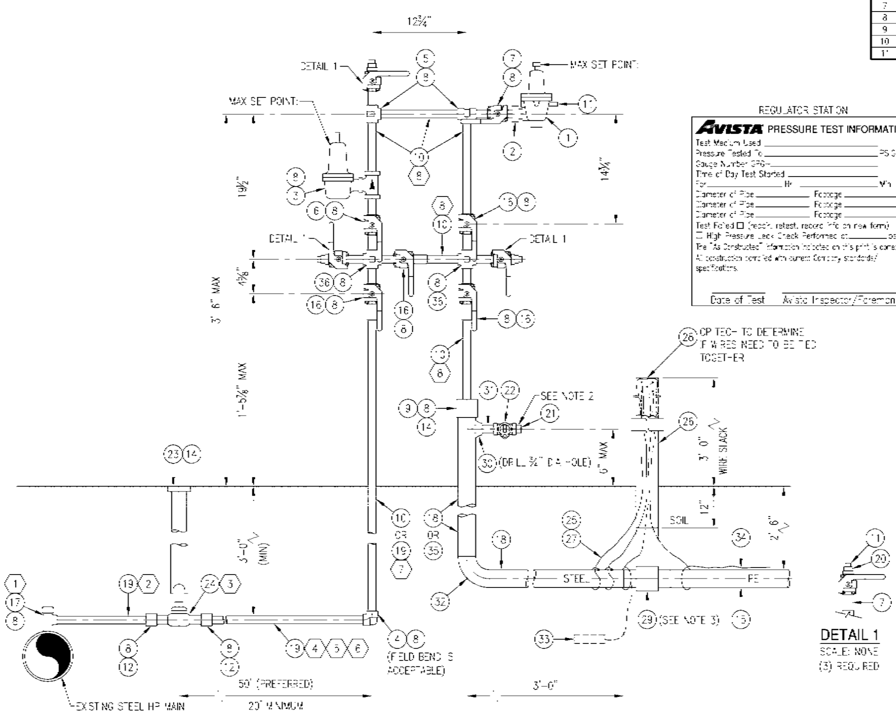
I-3719.../dwg

LOCATION PLAN
SCALE: NONE

VICINITY MAP
SCALE: NONE

SEC___ T___ R___



WELD FARM TAP
ELEVATION
SCALE: 1½" = 1'-0"

DETAIL 1
SCALE: NONE
(3) REQUIRED

CONSTRUCTION NOTES

SCOPE OF WORK	
INLET PIPING AND RISER PRESSURE TEST	TEST PER AVISTA STANDARDS, SPEC 3.18.
STATION PRESSURE TEST	TO TEST: REMOVE DIAPHRAGM SECTION OF REGULATOR & REPLACE WITH STEEL BLOCK-OFF CAP. REMOVE RELIEF VALVE AND COUPLING. REPLACE WITH ¾" PLUG. INSTALL ¾" PLUG IN INLET VALVE. INSTALL TEST HEAD ON OUTLET RISER. SUBJECT ENTIRE ASSEMBLY TO 900 PSIG (1,000 PSIG MAX) PRESSURE TEST. MONITOR WITH RECORDING CHART FOR 1 HOUR MINIMUM.
	RE-INSTALL REGULATOR BODY AND RELIEF VALVE AFTER THE TEST. SET REGULATOR AND RELIEF VALVE PRESSURES UPON START-UP.
OUTLET RISER AND PIPING PRESSURE TEST	TEST PER AVISTA STANDARDS, SPEC 3.18.
PAINT	REMOVE ALL RUST, SCALE, DIRT, OIL, ETC. APPLY ONE COAT OF PRIMER AND TWO COATS OF GRAY METER ENAMEL.
SOCKET SPACER RINGS	INSTALL SOCKET SPACER RINGS (ITEM 8) AT ALL SOCKET WELD JOINTS.

WELD INFORMATION

WELDERS(S)	
WELD PROCEDURE(S)	B1, B3, F4, F41, F42, F61

AS-BUILT MATERIAL INFORMATION

ITEM	MANUFACTURER	HEAT/LOT/SERIAL NUMBER	PURCHASE ORDER NUMBER	PIPE LENGTH
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				

REGULATOR STATION

AVISTA PRESSURE TEST INFORMATION

Test Medium Used ________
Pressure Tested To ________ PSIG
Gauge Number GPG- ________
Time of Day Test Started ________
For ________ Hr ________ Min
Diameter of Pipe ________ Footage ________
Diameter of Pipe ________ Footage ________
Diameter of Pipe ________ Footage ________
Test Failed ☐ (repair, retest, record info on new form)
☐ High Pressure Leak Check Performed at ________ psig
The "As Constructed" information indicated on this print is correct. All construction complied with current Company standards/specifications.

Date of Test ________ Avista Inspector/Foreman ________

INLET PIPE, VALVES AND FITTINGS

AVISTA PRESSURE TEST INFORMATION

Test Medium Used ________
Pressure Tested To ________ PSIG
Gauge Number GPG- ________
Time of Day Test Started ________
For ________ Hr ________ Min
Diameter of Pipe ________ Footage ________
Diameter of Pipe ________ Footage ________
Diameter of Pipe ________ Footage ________
Test Failed ☐ (repair, retest, record info on new form)
☐ High Pressure Leak Check Performed at ________ psig
The "As Constructed" information indicated on this print is correct. All construction complied with current Company standards/specifications.

Date of Test ________ Avista Inspector/Foreman ________

OUTLET PIPE AND FITTINGS

AVISTA PRESSURE TEST INFORMATION

Test Medium Used ________
Pressure Tested To ________ PSIG
Gauge Number GPG- ________
Time of Day Test Started ________
For ________ Hr ________ Min
Diameter of Pipe ________ Footage ________
Diameter of Pipe ________ Footage ________
Diameter of Pipe ________ Footage ________
Test Failed ☐ (repair, retest, record info on new form)
☐ High Pressure Leak Check Performed at ________ psig
The "As Constructed" information indicated on this print is correct. All construction complied with current Company standards/specifications.

Date of Test ________ Avista Inspector/Foreman ________

MATERIAL LIST LEGEND

(#) MATERIAL LIST ITEM

⬡# AS-BUILT MATERIAL LIST INFORMATION (HIGH PRESSURE ONLY)

NOTES:

1. BYPASS PORT OPTIONAL. INSTALL AS NEEDED IN FIELD.
2. IF CONNECTING TO AN EXISTING STEEL MAIN OR SERVICE DOWNSTREAM CONTACT GAS ENGINEERING. A CATHODIC INSULATION FITTING MAY BE REQUIRED.

MATERIAL LIST

NO	STOCK NO	QTY	DESCRIPTION
1	772-0132	1	FISHER, 1", 289-HH RELIEF VALVE
2	SHOP	1	COUPLING, 1"x ¾", REDUCING, THD, MALE ENDS 2,000 PSI
3	MTR SHOP	1	FISHER, ¾", 627R FARM TAP REGULATOR WITH ⅛" ORIFICE, SOCKET WELD BODY OR ENGINEERING APPROVED EQUIVALENT
4	770-2043	1	90° ELBOW, ¾", 3000 PSI, SOCKET WELD
5	770-7850	2	TEE, ¾", 3,000 PSI, SOCKET WELD
6	770-1270	1	BALL VALVE, ¾", STD PORT, 1,973 PSIG, EXTENDED PLAIN WELD ENDS
7	770-1270/ 770-1288	4	BALL VALVE, ¾", STD PORT, 1,973 PSIG, EXTENDED PLAIN WELD x THD ENDS
8	770-8856	29	SOCKET SPACER RING, ¾"
9	770-1355	1	COUPLING, 2"x ¾", SOCKET WELD, CL 3000
10	770-6090	10'	PIPE, ¾", STEEL, STD WALL, GRD B, BARE, PLAIN END
11	770-6570	4	RALSTON QUICK-TEST FITTING, 3,000 PSIG
12	770-1339	2	COUPLING, ¾", SOCKET WELD, CL 3000
13	770-3535	1	VALVE BOX, TOP SECTION AND LID
14	770-8858	1	SOCKET SPACER RING, 2"
15	770-6344	AS REQ'D	PIPE 2" PE, SDR 11, BI-MODAL, 20' STICK
16	770-1270/ 770-1271	4	BALL VALVE, ¾", STD PORT, 1,973 PSIG, EXTENDED PLAIN x EXTENDED SOCKET WELD ENDS
17	770-7823	1	CURB STOP TEE, 1" W/ ¾" SOCKET WELD, MUELLER H-17656
18	770-6237	3'	PIPE, 2", STEEL, STD WALL, X42, FBE COATED
19	770-6228	50'	PIPE, ¾", STEEL, STD WALL, GR B, FBE
20	732-0575	3	BUSHING, ¾"x ¼", THD, CL 3000
21	732-6118	1 OR 0	PLUG, ¾", THD, CL 3000 (OPTIONAL)
22	770-8560	1 OR 0	METER VALVE, ¾", LOCKWING, 175 PSIG, NON-INSUL (OPTIONAL)
23	770-3513	1	VALVE BOX, BOTTOM SECTION
24	770-8566	1	BALL VALVE, ¾", ANSI 300, W x W
25	283-1026	10'	WIRE, #10 SOLID, WHITE, INSULATED
26	578-0265	5'	CONDUIT, 3" PVC, SCH 40
27	770-9002	2	CADWELD PLUS COLOR CODED CONTAINER
28	770-7890	1	TEST BOX, YELLOW, 3", "BIG FINK"
29	770-7244	1	TRANSITION FITTING, 2" PE TO STEEL, WITH SLEEVE
30	770-8553	1 OR 0	THREAD-O-LET, ¾" (OPTIONAL)
31	732-5446	1 OR 0	NIPPLE, ¾", T-O, 3" LONG, SCH 40 (OPTIONAL)
32	770-2061	1	ELBOW, 2", 90 DEG, WELD, STD WALL
33	770-3172	1	ANODE, 20 LB, ZINC W/RED WIRE
34	283-1002	–	TRACER WIRE, #12 SOLID, YELLOW, INSULATED
35	770-6110	3'	PIPE, 2" STEEL, STD WALL, GR B, BARE
36	770-8753	2	CROSS, ¾", SOCKET WELD, CL 3000

DESIGN PARAMETERS

HP MAIN MAOP	PSIG
STATION INLET MAOP	PSIG, SMYS (¾", 0.113" WT, GR B)
STATION OUTLET MAOP	PSIG
STATION MAOP	600 PSIG, 8.0% SMYS (¾", 0.113" WT, GR B)
REGULATOR CAPACITY	= SCFH (APPROX) (⅛" ORIFICE, P1 MIN = PSIG, P2 = PSIG) FAILURE FLOW = SCFH @ PSIG INLET
RELIEF CAPACITY	= 32,000 SCFH (P2 = 66 PSIG, 58 PSIG SET POINT + 8 PSIG BUILDUP)
STATION CAPACITY	= 4,400 SCFH (BASED ON 70 FPS VELOCITY IN ¾" PIPE @ 55 PSIG)

ANY CHANGES TO THIS DRAWING MUST BE INCORPORATED AS APPLICABLE TO SHEET E-37970

STA #

NO	DATE	REVISION	BY	CKD	AS BUILT
6	8-24-22	UPDATE TRANSITION FITTING STOCK NUMBER	TJH	BRS	[redacted]
5	10-12-21	STANDARDS UPDATE	CCD	BRS	
4	4-12-19	STANDARDS UPDATE	CCD	SRS	
3	8-2-18	STANDARDS UPDATE	TLB	SRS	
2	8-25-17	STANDARDS UPDATE	LAJ	SRS	
1	2-16-16	STANDARDS UPDATE	LAJ	BRS	
0	9-18-15	STANDARDS UPDATE	CCD	TJH	

DISTRIBUTION - GAS STANDARD WELDED FARM TAP REGULATOR STATION PIPING - 2" OUTLET

AVISTA CORP
SPOKANE, WASHINGTON

NOTED	8-27-15	APPROVED
SCALE	DATE	9-18-15
DESIGN HARDING	CHECKED BRS	DATE
DRAWN DARNELL	NOTED	
CHECKED TJH	NOTED AI	SHT 1 OF 1 E-37842

AUTOCAD DWG

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E-37970

LOCATION PLAN

SCALE: NONE

VICINITY MAP

SCALE: NONE

CONSTRUCTION NOTES

SCOPE OF WORK	
INLET PIPING AND RISER PRESSURE TEST	TEST PER AVISTA STANDARDS, SPEC 3.18.
STATION PRESSURE TEST	TO TEST: REMOVE DIAPHRAGM SECTION OF REGULATOR & REPLACE WITH STEEL BLOCK-OFF CAP. REMOVE RELIEF VALVE AND COUPLING, REPLACE WITH ¾" PLUG. INSTALL ¾" PLUG IN INLET VALVE. INSTALL TEST HEAD ON OUTLET RISER. SUBJECT ENTIRE ASSEMBLY TO 900 PSIG (1000 PSIG MAX) PRESSURE TEST. MONITOR WITH RECORDING CHART FOR 1 HOUR MINIMUM.
	RE-INSTALL REGULATOR BODY AND RELIEF VALVE AFTER THE TEST. SET REGULATOR AND RELIEF VALVE PRESSURES UPON START-UP.
OUTLET RISER AND PIPING PRESSURE TEST	TEST PER AVISTA STANDARDS, SPEC 3.18.
PAINT	REMOVE ALL RUST, SCALE, DIRT, OIL, ETC. APPLY ONE COAT OF PRIMER AND TWO COATS OF GRAY METER ENAMEL.
SOCKET SPACER RINGS	INSTALL SOCKET SPACER RINGS (ITEM 8) AT ALL SOCKET WELD JOINTS.

WELD INFORMATION

WELDER(S):	
WELD PROCEDURE(S):	31, B3, F4, F41, F42, F61

AS-BUILT MATERIAL INFORMATION

ITEM	MANUFACTURER	HEAT/LOT/SERIAL NUMBER	PURCHASE ORDER NUMBER	PIPE LENGTH
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				

MATERIAL LIST

NO	STOCK NO	QTY	DESCRIPTION
1	MTR SHOP	1	FISHER, 1", 289 HH RELIEF VALVE
2	SHOP	1	COUPLING, 1" x ¾", REDUCING, THD, MALE ENDS 2000 PSI
3	MTR SHOP	1	FISHER, ¾", 627R FARM TAP REGULATOR WITH ⅛" ORIFICE, SOCKET WELD BODY OR ENGINEERING APPROVED EQUIVALENT
4	770-2043	2	90° ELBOW, ¾", 3,000 PSI, SOCKET WELD
5	770-7650	2	TEE, ¾", 3,000 PSI, SOCKET WELD
6	770-1270	1	BALL VALVE, ¾", STD PORT, 1,973 PSIG, EXTENDED PLAIN WELD ENDS
7	770-1270/ 770-1288	4	BALL VALVE, ¾", STD PORT, 1,973 PSIG, EXTENDED PLAIN WELD x THD ENDS
8	770-8656	28	SOCKET SPACER RING, ¾"
9	770-1270/ 770-1271	4	BALL VALVE, ¾", STD PORT, 1,973 PSIG, EXTENDED PLAIN x EXTENDED SOCKET WELD ENDS
10	770-6090	5'	PIPE, ¾", STEEL, STD WALL, GR B, BARE, PLAIN END
11	770-6670	4	RALSTON QUICK-TEST FITTING, 3,000 PSIG
12	770-1339	3	COUPLING, ¾", SOCKET WELD, CL 3000
13	770-0635	1	VALVE BOX, TOP SECTION AND LID
14	770-6342	3	PIPE, ¾" PE, SDR11, BI-MODAL, 500' COIL
15	770-8853	1 OR 0	THREAD-O-LET, ¾" (OPTIONAL)
16	732-5446	1 OR 0	NIPPLE, ¾", THD, 3" LONG, SCH 40 (OPTIONAL)
17	770-7823	1	CURB STOP TEE, 1" W/ ¾" SOCKET WELD, MUELLER H-17656
18	770-0172	1	ANODE, 20 LB, ZINC W/RED WIRE
19	770-6228	53'	PIPE, ¾", STEEL, STD WALL, GR B, FBE
20	732-0575	3	BUSHING, ¾" x ½", THD, CL 3000
21	732-6118	1 OR 0	PLUG, ¾", THD, CL 3000 (OPTIONAL)
22	770-8560	1 OR 0	METER VALVE, ¾", LOCKWING, 175 PSIG, NON-INSUL (OPTIONAL)
23	770-0613	1	VALVE BOX, BOTTOM SECTION
24	770-8626	1	BALL VALVE, ¾", ANSI 300, W x W
25	283-1026	10'	WIRE, #10 SOLID, WHITE, INSULATED
26	578-0265	5'	CONDUIT, 3" PVC, SCH 40
27	770-9002	2	CADWELD PLUS COLOR CODED CONTAINER
28	770-7690	1	TEST BOX, YELLOW, 3", "BIG FINK"
29	770-7240	1	TRANSITION FITTING, ¾" PE TO STEEL, WITH SLEEVE
30	283-1002	–	TRACER WIRE, #12 SOLID, YELLOW, INSULATED
31	770-8753	2	CROSS, ¾", SOCKET WELD, CL 3000

DESIGN PARAMETERS

HP MAIN MAOP	PSIG
STATION INLET MAOP	PSIG, SMYS (¾", 0.113" WT, GRD B)
STATION OUTLET MAOP	PSIG
STATION MAOP	600 PSIG, 8.0% SMYS (¾", 0.113" WT, GRD B)
REGULATOR CAPACITY	= SCFH (APPROX) (⅛" ORIFICE, P1 MIN = PSIG, P2 = PSIG) FAILURE FLOW = SCFH @ PSIG INLET
RELIEF CAPACITY	= 32,000 SCFH (P2 = 66 PSIG, 58 PSIG SET POINT – 8 PSIG BUILDUP)
STATION CAPACITY	= 4,400 SCFH (BASED ON 70 FPS VELOCITY IN ¾" PIPE @ 55 PSIG)

REGULATOR STATION

AVISTA PRESSURE TEST INFORMATION

Test Medium Used ______
Pressure Tested To ______ PSIG
Gauge Number GPG- ______
Time of Day Test Started ______
For ______ Hr ______ Min
Diameter of Pipe ______ Footage ______
Diameter of Pipe ______ Footage ______
Diameter of Pipe ______ Footage ______
Test Failed ☐ (repair, retest, record info on new form)
☐ High Pressure Leak Check Performed at ______ psig
The "As Constructed" information indicated on this print is correct. All construction complied with current Company standards/ specifications.

Date of Test   Avista Inspector/Foreman

INLET PIPE, VALVE AND FITTINGS

AVISTA PRESSURE TEST INFORMATION

Test Medium Used ______
Pressure Tested To ______ PSIG
Gauge Number GPG- ______
Time of Day Test Started ______
For ______ Hr ______ Min
Diameter of Pipe ______ Footage ______
Diameter of Pipe ______ Footage ______
Diameter of Pipe ______ Footage ______
Test Failed ☐ (repair, retest, record info on new form)
☐ High Pressure Leak Check Performed at ______ psig
The "As Constructed" information indicated on this print is correct. All construction complied with current Company standards/ specifications.

Date of Test   Avista Inspector/Foreman

OUTLET PIPE AND FITTINGS

AVISTA PRESSURE TEST INFORMATION

Test Medium Used ______
Pressure Tested To ______ PSIG
Gauge Number GPG- ______
Time of Day Test Started ______
For ______ Hr ______ Min
Diameter of Pipe ______ Footage ______
Diameter of Pipe ______ Footage ______
Diameter of Pipe ______ Footage ______
Test Failed ☐ (repair, retest, record info on new form)
☐ High Pressure Leak Check Performed at ______ psig
The "As Constructed" information indicated on this print is correct. All construction complied with current Company standards/ specifications.

Date of Test   Avista Inspector/Foreman

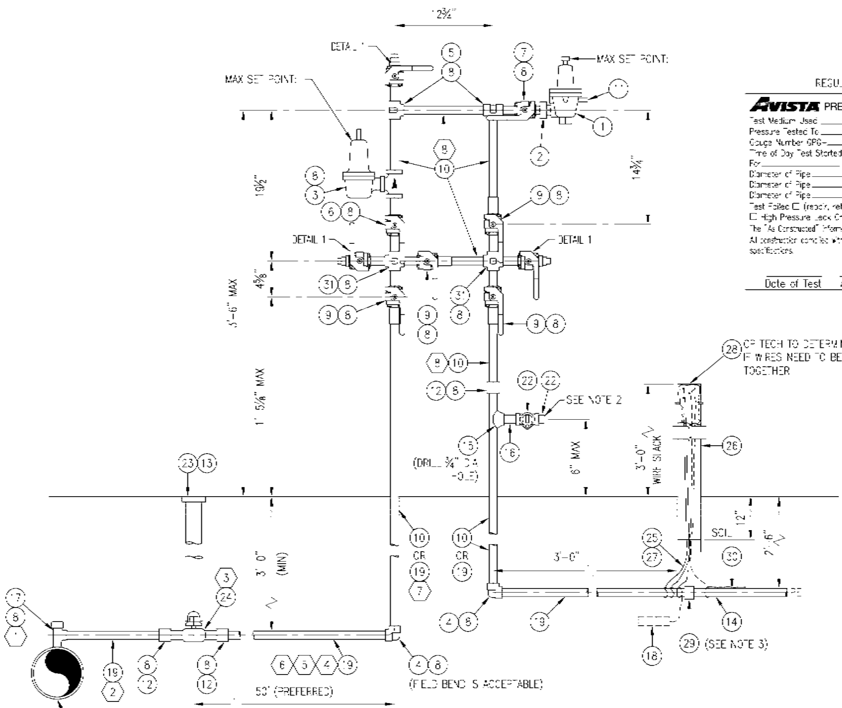
MATERIAL LIST LEGEND

(#) .... MATERIAL LIST ITEM

⟨#⟩ AS-BUILT MATERIAL LIST INFORMATION (HIGH PRESSURE ONLY)

NOTES:

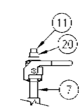
1. BYPASS PORT OPTIONAL. INSTALL AS NEEDED IN FIELD.
2. IF CONNECTING TO AN EXISTING STEEL MAIN OR SERVICE DOWNSTREAM CONTACT GAS ENGINEERING. A CATHODIC INSULATION FITTING MAY BE REQUIRED.



WELD FARM TAP

ELEVATION

SCALE: ½" = 1'-0"



DETAIL 1

SCALE: NONE

(3) REQUIRED

ANY CHANGES TO THIS DRAWING MUST BE INCORPORATED AS APPLICABLE TO SHEET E-37842

STA #

NO	DATE	REVISION	BY	CKD	AS BUILT
6	8-24-22	UPDATE TRANSITION FITTING STOCK NUMBER	TJH	BRS	
5	10-12-21	STANDARDS UPDATE	CDD	BRS	
4	9-12-19	STANDARDS UPDATE	CDD	SRS	
3	9-31-18	STANDARDS UPDATE	TLB	SRS	
2	8-25-16	STANDARDS UPDATE	JAJ	SRS	
1	2-16-16	STANDARDS UPDATE	JAJ	BRS	
0	9-18-15	STANDARDS UPDATE	CDD	TJH	

DISTRIBUTION - GAS
STANDARD
WELDED FARM TAP REGULATOR STATION
PIPING - 3/4" OUTLET

AVISTA CORP
SPOKANE, WASHINGTON

NOTED	9-30-15	APPROVED
SCALE	DATE	10-15-15 DATE
DESIGN HARDING	CHECKED BRS	
DRAWN DARNELL	NOTED	
CHECKED TJH	NOTED	SHT 1 OF 1 E-37970

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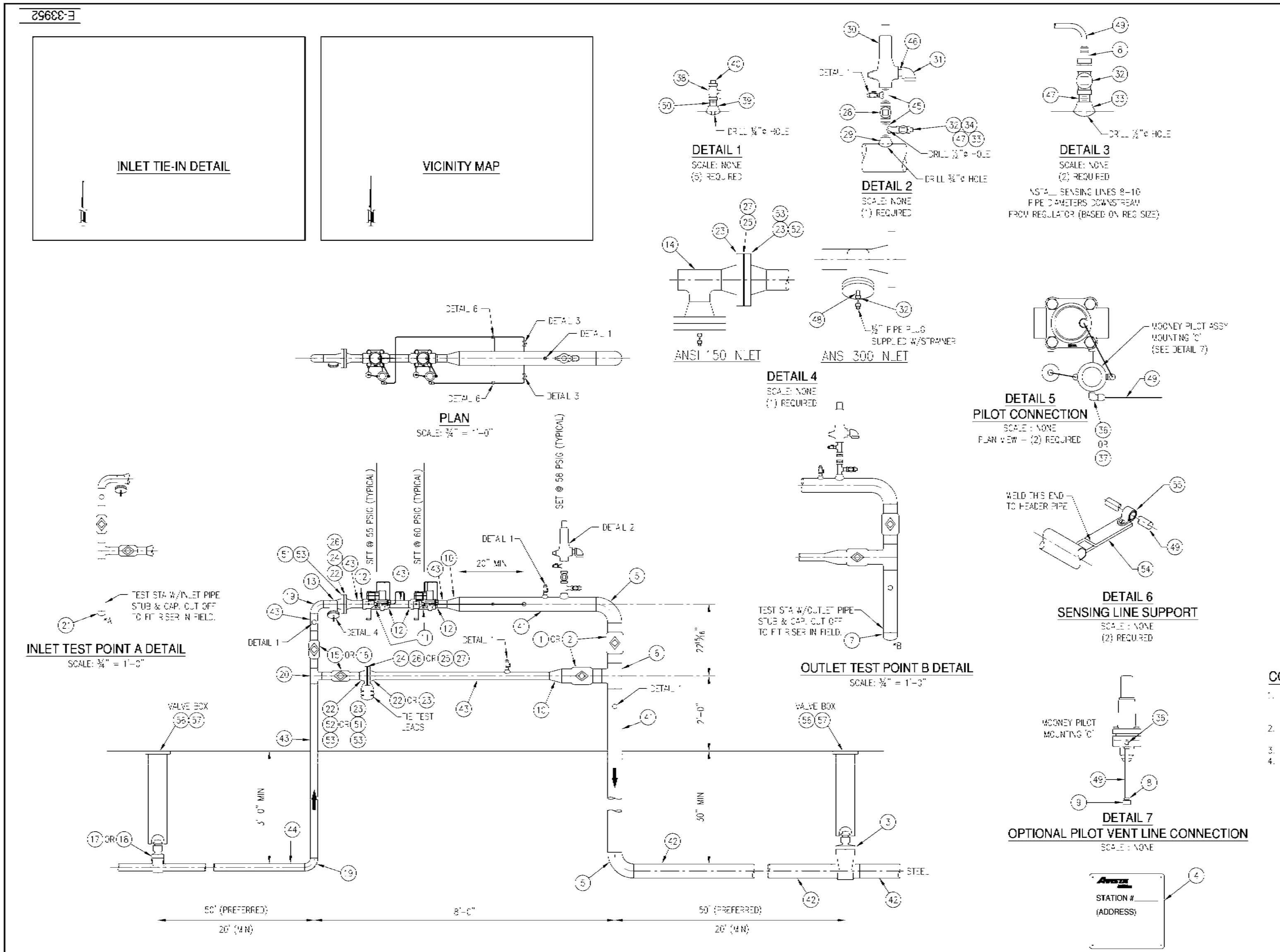

ELEVATION
SCALE: ¾" = 1'-0"

MOONEY PILOT
MOUNTING "C"

DETAIL 7
OPTIONAL PILOT VENT LINE CONNECTION
SCALE: NONE

STATION #______
(ADDRESS)

MATERIAL LIST				
ITEM	SIZE	STOCK NO.	QTY	DESCRIPTION
1	4"	770-8742	2	BALL VALVE, ANSI 300, 720 PSIG, WELD x WELD
2	4"	770-8710	2	BALL VALVE, ANSI 150, 275 PSIG, WELD x WELD
3	4"	770-8725	1	GATE VALVE, 500 PSIG, WELD x WELD
4	24" x 24"	REQUISITION	1	REG STA SIGN PER AVISTA SPECS
5	4"	770-2057	2	WELD ELBOW, 90, STD WALL, GRD B, LONG RADIUS
6	4"	770-7868	1	WELD TEE, STD WALL, GRD B
7	4"	770-0956	1	WELD CAP, STD WALL, GRD B
8	½" x ½"	SHOP	4	STRAIGHT TUBE CONNECTOR
9	–	SHOP	2	BUG SCREEN
10	4" x 2"	770-6808	2	CONCENTRIC WELD REDUCER, STD WALL, GRD B
11	2"	REQUISITION	2	MOONEY SINGLEPORT REGULATOR, CL600 1480 PSIG, SOCKET WELD ENDS, WITH SERIES 20 PILOT, TYPE 24 RESTRICTOR, TYPE 30 FILTER, MOUNTING "C"
12	2"	REQUISITION	4	SOCKET WELD SPACER RINGS
13	2"	770-7840	1	Y-STRAINER, ANSI 300, WELD x FLANGE
14	2"	770-7839	1	Y-STRAINER, ANSI 150, WELD x WELD
15	2"	770-8740	2	BALL VALVE, ANSI 300, 720 PSIG, WELD x WELD
16	2"	770-8700	2	BALL VALVE, ANSI 150, 275 PSIG, WELD x WELD
17	2"	REQUISITION	1	GATE VALVE, ANSI 300, 720 PSIG, WELD x WELD
18	2"	770-8715	1	GATE VALVE, 500 PSIG, WELD x WELD
19	2"	770-2051	2	WELD ELBOW, 90, STD WALL, GRD B, LONG RADIUS
20	2"	770-7859	1	WELD TEE, STD WALL, GRD B
21	2"	770-0950	1	WELD CAP, STD WALL, GRD B
22	2"	770-2310	3	WELD NECK FLANGE, ANSI 300, RAISED FACE
23	2"	770-2306	4	WELD NECK FLANGE, ANSI 150, RAISED FACE
24	2"	770-2475	2	FLANGE GASKET, ANSI 300, TYPE F, TEFLON
25	2"	770-2533	2	FLANGE GASKET, ANSI 150, TYPE F, TEFLON
26	2"	770-3258	2	FLANGE INSULATING KIT, ANSI 300
27	2"	770-3251	2	FLANGE INSULATION KIT, ANSI 150
28	¾"	770-1285	1	BALL VALVE, 600 PSIG, THRD, WITH HANDLE
29	¾"	770-8853	1	THREAD-O-LET, CL 3000
30	¾"	770-7175	1	ANDERSON-GREENWOOD RELIEF VALVE, TYPE 83
31	¾"	METER SHOP	1	SCREENED VENT ELBOW, THRD
32	½"	770-1282	4	BALL VALVE, 600 PSIG, THRD, WITH HANDLE
33	½"	770-8852	3	THREAD-O-LET, CL 3000
34	½"	732-6115	1	PLUG, THREADED, CL3000
35	½" x ¼"	770-8055	4	TUBE TO MALE NPT, ELBOW CONNECTOR
37	½" x ½"	770-8065	2	TUBE TO MALE NPT, STRAIGHT CONNECTOR
38	¼"	770-1275	5	BALL VALVE, 600 PSIG, THRD, WITH HANDLE
39	¼"	770-8851	5	THREAD-O-LET, CL 3000
40	¼"	770-6670	5	RALSTON QUICK-TEST FITTINGS, 3,000 PSIG
41	4"	770-6120	10 FT	PIPE, STEEL, STD. WALL 0.237", GRD B, BARE
42	4"	770-6238	40 FT	PIPE, STEEL, X-52, 0.188" WT, FBE COATED
43	2"	770-6110	10 FT	PIPE, STEEL, STD WALL 0.154", GRD B, BARE
44	2"	770-6237	40 FT	PIPE, STEEL, X-42, 0.154" WT, FBE COATED
45	¾"	732-5465	2	PIPE NIPPLE, SCHED 80, 6" LONG, THREADED
46	¾"	732-5436	1	PIPE NIPPLE, SCHED 40, CLOSE, THREADED
47	½"	732-5282	2	PIPE NIPPLE, SCHED 80, 4" LONG, THREADED
48	½"	732-5280	1	PIPE NIPPLE, SCHED 80, 2" LONG, THREADED
49	½"	770-8042	6 FT	STAINLESS STEEL TUBING, 2000 PSIG
50	¼"	732-5400	5	PIPE NIPPLE, SCHED 80, ½" LONG, THREADED
51	⅝"	770-0510	4	BOLT, GRD 8, YELLOW ZINC PLATED, 3" LONG
52	⅝"	770-0502	8	BOLT, GRD 8, YELLOW ZINC PLATED, 2¾" LONG
53	⅝"	770-5450	8	NUT, GRD 8, ZINC PLATED
54	–	SHOP	2	BAR, 1" x 3/16" x 8" LONG
55	–	SHOP	2	TUBING GROMMET & SCREW
56	–	770-0613	2	VALVE BOX BOTTOM
57	–	770-0635	2	VALVE BOX TOP

CONSTRUCTION NOTES:

1. SUBJECT STATION PIPING BETWEEN POINTS A & B TO A HIGH PRESSURE LEAK CHECK AT 100 PSIG. PRESSURE TEST TO 1.5 TIMES DESIGN MAOP WITH RECORDING CHART FOR FOUR HOURS MINIMUM.
2. INLET AND REGULATOR STATION VALVES TO MATCH OR EXCEED STATION DESIGN MAOP.
3. PIPE, FITTINGS & TEST PARAMETERS TO BE SPECIFIED BY DESIGNER.
4. REMOVE ALL RUST AND SCALE. APPLY ONE COAT OF PRIMER AND TWO COATS GRAY METER ENAMEL.

SUPERSEDES E-33952, DATED 06-25-97

NO	DATE	REVISION	BY	CKD	AS BUILT
7	10-12-21	UPDATED THREADED PLUG	DGD	BRS	
6	8-26-15	ADDED RALSTON QUICK-TEST FITTING	DGD	BRS	
5	08-06-14	STANDARDS UPDATE	JA	BRS	08-06-14
4	09-16-13	MINOR CORRECTIONS	TJH		
3	08-17-11	MINOR CORRECTIONS	TJH	RKB	
2	09-30-10	MINOR CORRECTIONS	TJH	RKB	
1	10-21-08	REVISED PER NOTES	RLB	DRm	

DISTRIBUTION - GAS
STANDARD
SINGLE RUN - DISTRICT REGULATOR STATION
WITH 2 INCH INLET/4 INCH OUTLET 275/600 PSIG MAOP MAX
ELEVATION, MATERIAL LIST & DETAILS

AVISTA CORP
SPOKANE, WASHINGTON

SCALE: NOTED | DATE: 11-16-07
DESIGN: T. BARRY | CHECKED: TLB
DRAWN: S. GRAF | NOTED:
CHECKED: | NOTED: AI
APPROVED: David Howell
DATE: 11-20-07
SHT 1 OF 1 E-33952

AUTOCAD DWG

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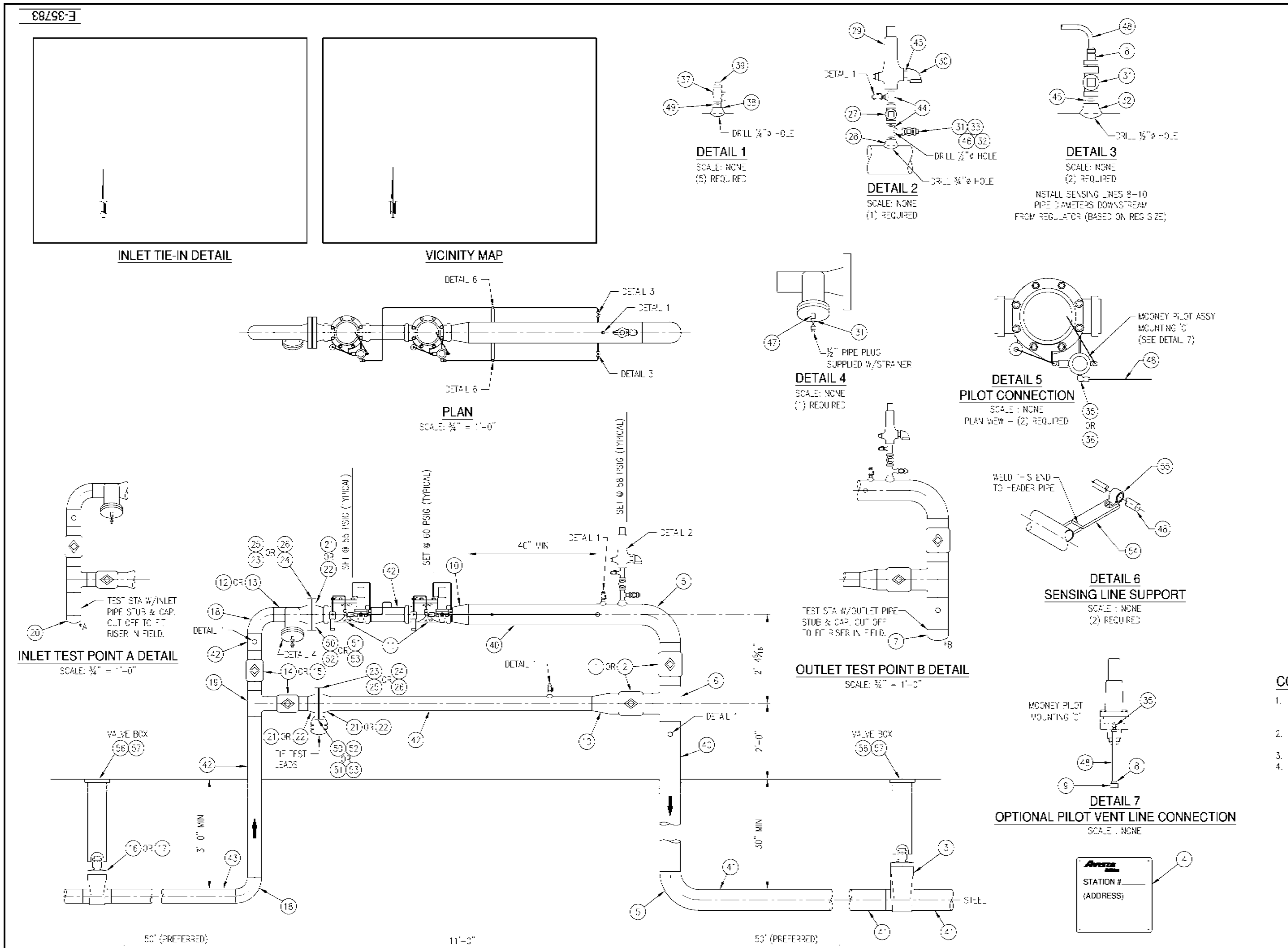

ITEM	SIZE	STOCK NO	QTY	DESCRIPTION
1	6"	770-6743	2	BALL VALVE, ANSI 300, 720 PSIG, WELD x WELD
2	6"	770-6712	2	BALL VALVE, ANSI 150, 275 PSIG, WELD x WELD
3	6"	770-6730	1	GATE VALVE, 500 PSIG, WELD x WELD
4	24" x 24"	REGULATION	1	REG STA SIGN PER AVISTA SPECS
5	6"	770-2067	2	WELD ELBOW, 90, STD WALL, GRD B, LONG RADIUS
6	6"	770-7869	1	WELD TEE, STD WALL, GRD B
7	6"	770-0957	1	WELD CAP, STD WALL, GRD B
8	1/2" x 1/2"	SHOP	4	STRAIGHT TUBE CONNECTOR
9	–	SHOP	2	BUG SCREEN
10	6" x 4"	770-6812	2	CONCENTRIC WELD REDUCER, STD WALL, GRD B
11	4"	REGULATION	2	MOONEY SINGLEPORT REGULATOR, ANSI 150-300, 1480 PSIG, BUTT WELD ENDS, WITH SERIES 20 PILOT, TYPE 24 RESTRICTOR, TYPE 30 FILTER, MOUNTING "C"
12	4"	770-7842	1	T-STRAINER, ANSI 300, WELD x FLANGE
13	4"	770-7841	1	T-STRAINER, ANSI 150, WELD x FLANGE
14	4"	770-6742	2	BALL VALVE, ANSI 300, 720 PSIG, WELD x WELD
15	4"	770-6710	2	BALL VALVE, ANSI 150, 275 PSIG, WELD x WELD
16	4"	REGULATION	1	GATE VALVE, ANSI 300, 720 PSIG, WELD x WELD
17	4"	770-6725	1	GATE VALVE, 500 PSIG, WELD x WELD
18	4"	770-2057	2	WELD ELBOW, 90, STD WALL, GRD B, LONG RADIUS
19	4"	770-7868	1	WELD TEE, STD WALL, GRD B
20	4"	770-0956	1	WELD CAP, STD WALL, GRD B
21	4"	770-2312	3	WELD NECK FLANGE, ANSI 300, RAISED FACE
22	4"	770-2308	3	WELD NECK FLANGE, ANSI 150, RAISED FACE
23	4"	770-2485	2	FLANGE GASKET, ANSI 300, TYPE F, TEFLON
24	4"	770-2534	2	FLANGE GASKET, ANSI 150, TYPE F, TEFLON
25	4"	770-3268	2	FLANGE INSULATING KIT, ANSI 300
26	4"	770-3266	2	FLANGE INSULATING KIT, ANSI 150
27	3/4"	770-1285	1	BALL VALVE, 600 PSIG, THD, WITH HANDLE
28	3/4"	770-6853	1	THREAD-O-LET, CL 3000
29	3/4"	770-7175	1	ANDERSON-GREENWOOD RELIEF VALVE, TYPE 83
30	3/4"	METER SHOP	1	SCREENED VENT ELBOW, THD
31	1/2"	770-1282	4	BALL VALVE, 600 PSIG, THD, WITH HANDLE
32	1/2"	770-6852	3	THREAD-O-LET, CL 3000
33	1/2"	732-6115	1	PLUG, THREADED, CL3000
35	1/2" x 1/4"	770-8055	4	TUBE TO MALE NPT, ELBOW CONNECTOR
36	1/2" x 1/2"	770-8035	2	TUBE TO MALE NPT, STRAIGHT CONNECTOR
37	1/4"	770-1275	5	BALL VALVE, 600 PSIG, THD, WITH HANDLE
38	1/4"	770-6851	5	THREAD-O-LET, CL 3000
39	1/4"	770-6670	5	RALSTON QUICK-TEST FITTING, 3,000 PSIG
40	6"	770-6125	10 FT	PIPE, STEEL, STD WALL 0.280", GRD B, BARE
41	6"	770-6241	40 FT	PIPE, STEEL, X-52, 0.219" WT, FBE COATED
42	4"	770-6120	10 FT	PIPE, STEEL, STD WALL 0.237", GRD B, BARE
43	4"	770-6238	40 FT	PIPE, STEEL, X-52, 0.188" WT, FBE COATED
44	3/4"	732-5465	2	PIPE NIPPLE, SCH 80, 6" LONG, THD
45	3/4"	732-5436	3	PIPE NIPPLE, SCH 40, CLOSE, THD
46	1/2"	732-5262	1	PIPE NIPPLE, SCH 80, 4" LONG, THD
47	1/2"	732-5260	1	PIPE NIPPLE, SCH 80, 2" LONG, THD
48	1/2"	770-8042	12 FT	STAINLESS STEEL TUBING, 2000 PSIG
49	1/4"	732-5400	5	PIPE NIPPLE, SCH 80, 1 1/2" LONG, THD
50	3/4"	770-0530	16	BOLT, GRD 5, YELLOW ZINC PLATED, 3" LONG (ANSI 300)
51	5/8"	770-0510	16	BOLT, GRD 5, YELLOW ZINC PLATED, 3" LONG (ANSI 150)
52	3/4"	770-5455	16	NUT, GRD 8, ZINC PLATED
53	5/8"	770-5450	16	NUT, GRD 8, ZINC PLATED
54	–	SHOP	2	BAR, 1" x 3/16" x 8" LONG
55	–	SHOP	2	TUBING GROMMET & SCREW
56	–	770-0613	2	VALVE BOX BOTTOM
57	–	770-0635	2	VALVE BOX TOP

MATERIAL LIST

CONSTRUCTION NOTES:

1. SUBJECT STATION PIPING BETWEEN POINTS A & B TO A HIGH PRESSURE LEAK CHECK AT 100 PSIG. PRESSURE TEST TO 1.5 TIMES DESIGN MAOP WITH RECORDING CHART FOR FOUR HOURS MINIMUM.
2. INLET AND REGULATOR STATION VALVES TO MATCH OR EXCEED STATION DESIGN MAOP.
3. PIPE, FITTINGS & TEST PARAMETERS TO BE SPECIFIED BY DESIGNER.
4. REMOVE ALL RUST AND SCALE. APPLY ONE COAT OF PRIMER AND TWO COATS GRAY METER ENAMEL.

SUPERSEDES E-35783, DATED 08-21-01

NO	DATE	REVISION	BY	CKD	AS BUILT
7	10-12-21	UPDATED THREADED PLUG	CGD	JRS	
6	8-26-15	ADDED RALSTON QUICK-TEST FITTING	CGD	JRS	
5	08-06-14	STANDARDS UPDATE	JA	DRS	08-06-14 JA DRS
4	09-16-13	MINOR CORRECTIONS	T.H		
3	08-17-11	MINOR CORRECTIONS	T.H	RKB	
2	09-30-10	MINOR CORRECTIONS	T.H	RKB	
1	10-21-08	REVISED PER NOTES	R.B	DRH	

DISTRIBUTION - GAS
STANDARD
SINGLE RUN - DISTRICT REGULATOR STATION
WITH 4 INCH INLET/6 INCH OUTLET 275/600 PSIG MAOP
ELEVATION, MATERIAL LIST & DETAILS

AVISTA CORP
SPOKANE, WASHINGTON

SCALE	DATE	APPROVED
NOTED	11-16-07	David Howell
DESIGN T. BARRY	CHECKED TLB	11-19-07 (DATE)
DRAWN S. GRAF	NOTED	
CHECKED	NOTED	SHT 1 OF 1 E-35783

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10/12/2021 1:10 PM
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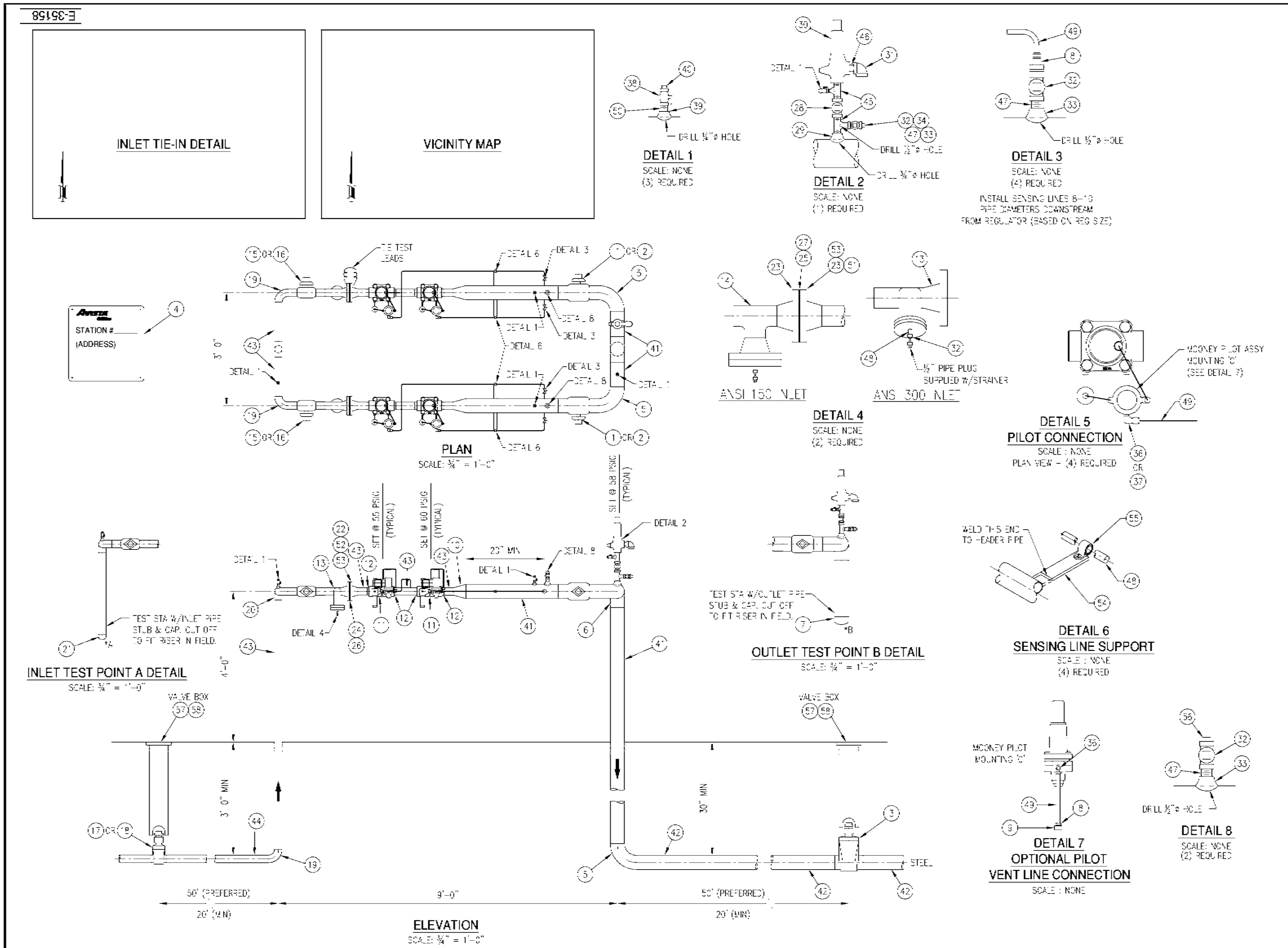

MATERIAL LIST

ITEM	SIZE	STOCK NO.	QTY	DESCRIPTION
1	4"	770-8742	2	BALL VALVE, ANSI 300, 720 PSIG, WELD x WELD
2	4"	770-8710	2	BALL VALVE, ANSI 150, 275 PSIG, WELD x WELD
3	4"	770-8725	1	GATE VALVE, 500 PSIG, WELD x WELD
4	24" x 24"	REQUISITION	1	REG STA SIGN PER AVISTA SPECS
5	4"	770-2057	3	WELD ELBOW, 90, STD WALL, GRD B, LONG RADIUS
6	4"	770-7858	1	WELD TEE, STD WALL, GRD B
7	4"	770-0956	1	WELD CAP, STD WALL, GRD B
8	½" x ½"	SHOP	6	STRAIGHT TUBE CONNECTOR
9	–	SHOP	4	BUG SCREEN
10	4" x 2"	770-6508	2	CONCENTRIC WELD REDUCER, STD WALL, GRD B
11	2"	REQUISITION	4	MOONEY SINGLEPORT REGULATOR, CLECO, 1480 PSIG, SOCKET WELD ENDS, WITH SERIES 20 PILOT, TYPE 24 RESTRICTOR, TYPE 30 FILTER, MOUNTING "C"
12	2"	REQUISITION	8	SOCKET WELD SPACER RINGS
13	2"	770-7840	2	T-STRAINER, ANSI 300, WELD x FLANGE
14	2"	770-7839	2	T-STRAINER, ANSI 150, WELD x WELD
15	2"	770-8740	2	BALL VALVE, ANSI 300, 720 PSIG, WELD x WELD
16	2"	770-8700	2	BALL VALVE, ANSI 150, 275 PSIG, WELD x WELD
17	2"	REQUISITION	1	GATE VALVE, ANSI 300, 720 PSIG, WELD x WELD
18	2"	770-8715	1	GATE VALVE, 500 PSIG, WELD X WELD
19	2"	770-2051	3	WELD ELBOW, 90, STD WALL, GRD B, LONG RADIUS
20	2"	770-7859	1	WELD TEE, STD WALL, GRD B
21	2"	770-0950	1	WELD CAP, STD WALL, GRD B
22	2"	770-2310	2	WELD NECK FLANGE, ANSI 300, RAISED FACE
23	2"	770-2305	4	WELD NECK FLANGE, ANSI 150, RAISED FACE
24	2"	770-2475	2	FLANGE GASKET, ANSI 300, TYPE F, TEFLON
25	2"	770-2533	2	FLANGE GASKET, ANSI 150, TYPE F, TEFLON
26	2"	770-3258	2	FLANGE INSULATING KIT, ANSI 300
27	2"	770-3261	2	FLANGE INSULATING KIT, ANSI 150
28	¾"	770-1285	1	BALL VALVE, 600 PSIG, THD, WITH HANDLE
29	¾"	770-8853	1	THREAD-O-LET, CL 3000
30	¾"	770-7175	1	ANDERSON-GREENWOOD RELIEF VALVE, TYPE 83
31	¾"	METER SHOP	1	SCREENED VENT ELBOW, THD
32	½"	770-1282	7	BALL VALVE, 600 PSIG, THD, WITH HANDLE
33	½"	770-8852	5	THREAD-O-LET, CL 3000
34	½"	732-6115	3	PLUG, THREADED, CL3000
35	½" x ½"	770-8057	4	TUBE TO MALE NPT, ELBOW CONNECTOR
36	½" x ½"	770-8055	8	TUBE TO MALE NPT, ELBOW CONNECTOR
37	½" x ½"	770-8065	2	TUBE TO MALE NPT, STRAIGHT CONNECTOR
38	¼"	770-1275	5	BALL VALVE, 600 PSIG, THD, WITH HANDLE
39	¼"	770-8851	5	THREAD-O-LET, CL 3000
40	¼"	770-6670	5	RALSTON QUICK-TEST FITTING, 3,000 PSIG
41	4"	770-6120	15 FT	PIPE, STEEL, STD WALL 0.237", GRD B, BARE
42	4"	770-6238	40 FT	PIPE, STEEL, X-52, 0.185" WT, FBE COATED
43	2"	770-6110	12 FT	PIPE, STEEL, STD WALL 0.154", GRD B, BARE
44	2"	770-6237	40 FT	PIPE, STEEL, X-42, 0.154" WT, FBE COATED
45	¾"	732-5465	2	PIPE NIPPLE, SCH 80, 6" LONG, THD
46	¾"	732-5435	1	PIPE NIPPLE, SCH 40, CLOSE, THD
47	½"	732-5262	4	PIPE NIPPLE, SCH 80, 4" LONG, THD
48	½"	732-5260	2	PIPE NIPPLE, SCH 80, 2" LONG, THD
49	½"	770-8042	20 FT	STAINLESS STEEL TUBING, 2000 PSIG
50	¼"	732-5400	5	PIPE NIPPLE, SCH 80, 1½" LONG, THD
51	⅝"	770-0500	8	BOLT, GRD 8, YELLOW ZINC PLATED, 3½" LONG
52	⅝"	770-0502	8	BOLT, GRD 8, YELLOW ZINC PLATED, 3¾" LONG
53	⅝"	770-5450	8	NUT, GRD 8, ZINC PLATED
54	–	SHOP	4	BAR, 1" x 3/16" x 8" LONG
55	–	SHOP	4	TUBING GROMMET & SCREW
56	½"	732-6114	2	PIPE PLUG, SCH 40, THD
57	–	770-0635	2	VALVE BOX TOP
58	–	770-0613	2	VALVE BOX BOTTOM

CONSTRUCTION NOTES:

1. SUBJECT STATION PIPING BETWEEN POINTS A & B TO A HIGH PRESSURE LEAK CHECK AT 100 PSIG. PRESSURE TEST TO 1.5 TIMES DESIGN MAOP WITH RECORDING CHART FOR FOUR HOURS MINIMUM.
2. INLET AND REGULATOR STATION VALVES TO MATCH OR EXCEED STATION DESIGN MAOP.
3. PIPE, FITTINGS & TEST PARAMETERS TO BE SPECIFIED BY DESIGNER.
4. REMOVE ALL RUST AND SCALE. APPLY ONE COAT OF PRIMER AND TWO COATS GRAY METER ENAMEL.

WITH 2 INCH INLET/4 INCH OUTLET 275/600 PSIG MAOP MAX

SUPERSEDES E-35158, DATED 02-07-94

NO	DATE	REVISION
7	10-12-21	UPDATED THREADED PLUG
6	8-26-15	ADDED RALSTON QUICK-TEST FITTING
5	05-09-14	STANDARDS UPDATE
4	10-09-13	MINOR CORRECTIONS
3	03-17-11	MINOR CORRECTIONS
2	06-30-10	MINOR CORRECTIONS
1	10-21-08	REVISED PER NOTES

DISTRIBUTION - GAS
STANDARD
DUAL RUN - DISTRICT REGULATOR STATION
WITH 2 INCH INLET/4 INCH OUTLET 275/600 PSIG MAOP MAX
ELEVATION, MATERIAL LIST & DETAILS

AVISTA CORP.
SPOKANE, WASHINGTON

SCALE: NOTED
DATE: 11-20-07
DESIGN: T. BARRY
DRAWN: S. GRAF
APPROVED
DATE: 11-26-07
SHT 1 OF 1
E-35158

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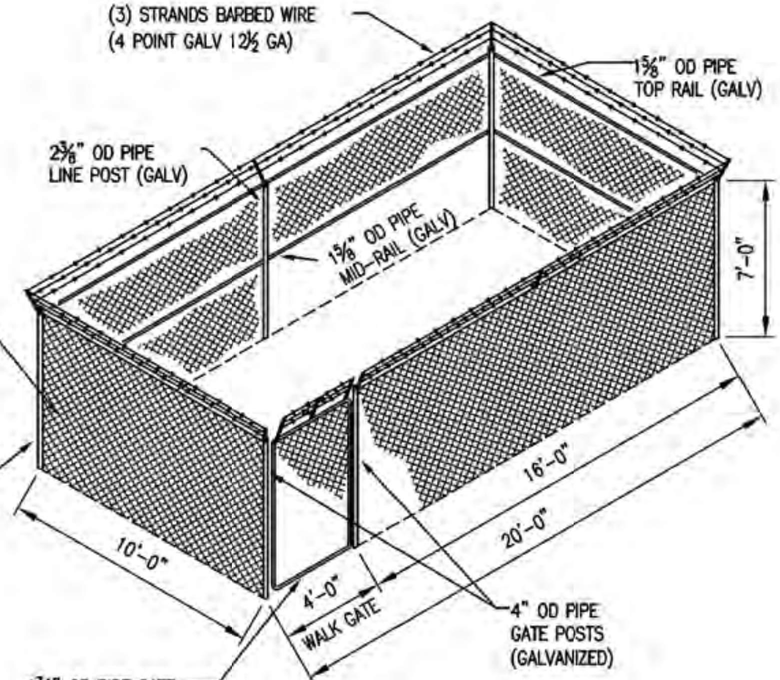
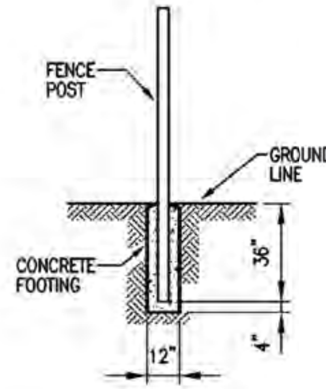


CHAIN LINK FENCE FABRIC.
VERTICAL REDWOOD COLORED, TUBULAR VINYL SLATS MAY BE ADDED WHEN REQUIRED BY LOCAL JURISDICTION, LANDOWNER, ETC. PREFERENCE IS TO LEAVE FENCE FABRIC OPEN WITHOUT SLATS FOR IMPROVED SECURITY MONITORING.

TYPICAL FENCE LAYOUT



BOTTOM OF CONCRETE FOOTING TO BE SET BELOW FROST LINE. (SEE LOCAL CODE). FOOTING SIZE IS THE RECOMMENDED MINIMUM.

CONCRETE FOOTING DETAIL

NOTE:
THE GATE LATCH ASSEMBLY MUST BE LOCKABLE BY MEANS OF AN AVISTA PADLOCK.

DISTRIBUTION GAS
STANDARD
REG STA FENCING DETAILS
AVISTA CORP
SPOKANE, WASHINGTON

NO	DATE	REVISION	BY	CKD
2	8-19-08	REVIEW SLAT NOTE	RLB	DRH
1	10-04	REVISED FENCE SLATS MATERIAL	JW	

SCALE: NONE
DATE: 10-22-02
DSN: AVISTA
CKD:
DR: JW
NTD:
CKD:
NTD: JW
APPROVED:
DATE: 11-25-02
SHT 1 OF 1
L-36082

AUTOCAD DWG

2.25 TELEMETRY DESIGN

<u>SCOPE:</u>

To establish a standard design for gas telemetry systems.

<u>REGULATORY REQUIREMENTS:</u>

§192.741

NFPA 70: National Electrical Code (NEC), including Articles 500, 501, 504

<u>OTHER REFERENCES:</u>

AGA XL1001, Classification of Locations for Electrical installations in Gas Utility Areas

<u>CORRESPONDING STANDARDS:</u>

Spec. 2.22, Meter Design
Spec. 2.23, Regulator Design
Spec. 2.24, Meter & Regulator Tables & Drawings
Spec. 4.51, Gas Control Room Management Plan

<u>DESIGN REQUIREMENTS:</u>

General

Telemetry systems, including alarm set points, should be specified by Gas Engineering.

In general, telemetry is used to monitor system pressures, volumes, and flows from areas of special interest such as gate stations, gas transportation customers, district regulator stations, selected large industrial customers, and distribution systems with more than one source of gas.

Each distribution system supplied by more than one pressure regulating station must be equipped with telemetry, an electronic pressure recorder, or a mechanical chart recorder to monitor the gas pressure. Telemetry is preferred. Sites with telemetry should alarm for pressures that exceed the MAOP and for pressures that fall below reasonable levels for reliable operation. For single-source distribution systems, the Construction Manager in conjunction with Gas Engineering should determine the necessity of installing telemetry or recording gauges, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions that might warrant the installation of monitoring devices.

Data Collected

Data collected generally includes metering pressure, gas temperature, corrected and uncorrected gas volume, pressure upstream and downstream from regulation points, and odorizer alarms. The local instrument, either an electronic corrector, electronic pressure recorder, or a programmable logic controller (PLC)/remote terminal unit (RTU)/flow computer, calculates and transmits: corrected gas volume and flow, and reports this information along with measured pressures and temperatures, high and low pressure alarms, ambient or case temperature, instrument alarms such as pulse switches, tamper, instrument main battery, memory battery, and communications battery voltage and alarms, high flow alarms in selected cases, and alarm set points.

Depending on the nature of the installation, data collected ranges from pulse accumulator volumes (from a meter that has internal temperature compensation), to complete data (from meters with electronic correctors) to pressure, flow, volume, and gas temperature.

Gate stations with flow computers/PLCs/RTUs should measure and report complete pressure, temperature, volume, and flow data that is measured via transducers on upstream, metering, and downstream piping. This may also include data such as corrected volumes, flows, and pressures from the interstate pipeline companies, as obtained from their instruments at a gate station.

Data Path and Uses

Field data is collected with AutoSol Enterprise Service (AES) software, developed by Automation Solutions, Inc. Avista's AutoSol server communicates with the field devices via a bank of conventional analog telephone line modems (POTS, "plain old telephone service") and Internet Protocol (IP) communications. New installations should be IP-based since the use of conventional land lines is being phased out by Avista.

Field instruments collect and record hourly data, typically maintaining at least a 30 day history. The AES server polls the field devices and downloads hourly summary data from the instruments. Polling ranges from several times per day for older battery powered installations on landlines to once every 15 minutes for selected AC powered devices.

The data collected by the AES server is placed on a network file share where SCADA, Nucleus, and PI load it for multiple users including the Natural Gas Resources Department's use for daily nominations and transactions with interstate pipeline companies and customers, and Gas Engineering.

Nucleus is the data warehouse and long-term repository for hourly billing data. This data is used to create reports for both internal and external consumption. Some transportation customers receive daily and/or monthly reports regarding usage at their site. The data in such reports is sent to customers as a courtesy, not for billing purposes. It is considered to be "un-scrubbed" raw data and is provided on a best-effort basis.

Data is also transferred from the AutoSol server to Avista's SCADA system for use by Gas Control. The SCADA displays and information are also available to multiple users throughout Avista including Gas Engineering, Pressure Controlmen, and Managers.

Data in SCADA is value reported at the time the field device was polled. SCADA's primary function is alarming and reporting present readings with an option for a demand scan (forced polling) initiated by a Gas Controller. Official billing hourly volume data is stored in Nucleus, not in PI or SCADA.

PI stores both instantaneous data and historical data. For Mercury/Honeywell instruments, additional data in the audit trail for pressure history is periodically directly transferred several times daily to PI and typically includes the maximum, average, and minimum pressures during the hourly interval, in addition to the values at the time of polling. ABB TotalFlow flow computers also provide 1 minute trend files for selected data. PI is accessible by multiple users within Avista.

Historic gas volume hourly data is stored in PI and Nucleus.

EQUIPMENT CONFIGURATION:

Gate Stations

New and retrofitted measurement and telemetry installations at gate stations should utilize an ABB TotalFlow flow computer/RTU.

Gate stations should be connected to receive un-corrected pulses from the interstate pipeline company's turbine or rotary meter which is established as the sole billing meter. Avista's transducers for pressure and temperature at the meter should be connected to Avista's RTUs and/or correctors and pressure monitors so that Avista's equipment can provide our check correction. Additional pressures and temperatures upstream and downstream of Avista-owned and operated gas heaters are also recommended.

Orifice meters require direct measurement of differential pressure as well as static pressure as there are no moving parts or sensors to provide a pulse.

Coriolis and ultrasonic meters generally require a pulse splitter to share their output with the interstate pipeline and Avista as they measure mass flow directly and convert that signal to pulses that indicate the flow rate. Avista's flow computer then converts the flow rate to volume and flow in our standard units of MCF or CCF.

The instruments should calculate corrected volumes, flows, and alarms, and report this information along with pressures, temperatures, internal instrument status, and alarms. AC power with battery backup is required.

Where injection type odorizers (typically YZ brand) are owned and operated by Avista, the flow computer should generate the control signal which is typically 4 – 20 mA based on the calculated flow rate.

Gas Transport and Telemetry Customers

Gas Transportation ("Transport") customers should have a Mercury/Honeywell Instruments Model Mini AT PT or PPT or Mini Max electronic volume corrector installed with inputs from the meter for pulses (or by mechanical coupling when mounted on the meter) and transducers for pressure and temperature. Rotary meters with Dresser Micro PTZ correctors providing corrected pulse output may also be utilized depending on the application. Additional pressure monitoring such as the pressure delivered to the customer or upstream pressure if different than the metering pressure will be evaluated by Gas Engineering on a site-specific basis.

Communications should be via a Mercury Instruments "MI Wireless" communications package with a cellular modem and an AC power supply and rechargeable battery backup. The corrector should also have an internal battery backup. Refer to "Transport Customers" within this specification for further detail.

Regulator Sites and System Pressure Monitoring

Regulator station sites and other pressure monitoring points selected for telemetry installations should have a Mercury Instruments model "ERX" electronic pressure recorder in a common enclosure from the manufacturer that includes the MI Wireless communications package, power supply, rechargeable communications battery, and 6 volt battery backup independent of the communications battery. AC power supply is preferred. Solar may be used with Gas Engineering's approval on a site-specific basis. Both upstream and downstream pressures should be monitored with the instrument located nearest to the high pressure side to minimize sense line tubing length for the highest pressure line.

Power Plants

Power plants requirements are site specific. Gas Engineering should be involved very early in the planning and design process. An ABB TotalFlow flow computer is preferred. A Mercury / Honeywell instruments Mini AT-PT may be acceptable. Instruments should have an AC power supply, rechargeable battery backup, memory backup battery independent of the communications battery, and IP based communications.

Table for detailed reference to quantities measured:

Table for detailed reference to quantities measured:

Site	Quantities Measured (Inputs/Outputs)
Gate Stations	Pulses for volume, uncorrected from the interstate pipeline company's meter.
	Pulses for volume, corrected from the interstate pipeline company's meter or PLC when we do not calculate our own volume.
	Flow rate, corrected, from the interstate pipeline company's PLC or flow computer when we do not calculate our own flow rate.
	Pressure at each meter.
	Differential pressure at orifice meters.
	Pressure to Avista HP, IP, and distribution systems.
	Pressure in the pipelines' upstream line.
	Gas temperature at each meter.
	Gas temperature upstream and downstream of Avista owned gas heaters.
	Ambient air temperature.
	Alarm contacts from the odorizer's common alarm when used.
	Alarms such as security, tamper, valve position, interstate pipeline company, etc. when available.
	AC Power failure or battery charger failure.
	Communications battery voltage.
	Output: Analog output to odorizer, 4-20 mA signal based on flow, preferably from Avista's flow computer. Avista may use a 4-20 mA signal from the pipelines' flow computer until we have our own.
Regulator Stations	Pressure upstream of the regulator(s).
	Pressure downstream of the regulator(s).
	Communications battery voltage.
Gas Transportation Customers	Pressure at meter.
	Gas temperature at meter.
	Pulses from meter either by mechanical coupling, pulser, or pulses, depending on meter.
	Downstream or customer pressure, or upstream pressure, depending on metering configuration, and location on system.

Notes: *Instruments calculate corrected volume, corrected flow rates, and alarms based on the inputs and programming. There are internal measurements that the instruments also provide such as case temperature, main battery voltage, and index switch fail, which we also utilize.*

Some equipment at some transport customers may not support telemetering of pressure and temperature such as when utilizing pulses from a fixed factor or temperature compensated meter or from a corrector (e.g., Dresser micro PTZ) that does not support communications directly with AutoSol.

Communications

Internet Protocol (IP) based communications is the preferred choice.

- Sierra Wireless RV50, Raven XT, or XE cellular gateway for packet switched data on the Verizon or AT&T cellular networks for communicating via IP wirelessly. For non-flow computer installations, a Mercury Instruments MI Wireless communications box with a port server may be used for up to four Mercury devices.
- Avista Ethernet, (wireless when available) as part of "smart grid" projects or near an electric substation or other facility where Avista has Ethernet.
- Land line telephone lines (POTS) and dial-up modems are the last choice for new installations due to slow speed and long scan times by the AutoSol modem bank.
- Priorities
    - New installations
    - Gate stations
    - Pressure monitoring stations
    - Transportation customers

Power Source

AC Line power with self-contained rechargeable battery backup is preferred.
Solar voltaic power or thermoelectric utilizing gas for fuel may be considered for certain locations with Gas Engineering's approval, depending on the location, data being acquired and its purpose, and the economics of providing AC power to the site.

Electrical Classification

Outdoor area classification for electrical installations are based on:

- NFPA 70 / National Electrical Code (NEC) with particular attention to Articles 500, 501, 504 relating to Hazardous (Classified Locations, primarily with respect to Class I, Divisions 1 and 2.
- American Gas Association (AGA) XL1001, Classification of Locations for Electrical Installations in Gas Utility Areas.
- Areas within 5 feet of or directly above any relief valves or automatic vents will be treated as Class I Division 1 (likely to have gas present during normal operation).
- Areas within 15 feet of any flanges, screwed connection, valves, relief valves, or vents will be treated as Class I Division 2 (likely to have gas present only during abnormal operation).
- Underground (buried) flanges, screwed connections, or valves create a class I Division 2 area above the ground.
- Electrical equipment should not be installed in the direct path of discharge from vents or relief valves.
- Areas including pipe without valves, flanges, or screwed connections are considered non-hazardous (ordinary) areas.
- Electronic correctors mounted on meters with or without telemetry must comply with the applicable version of the NEC, Articles 500, 501, and 504 for Hazardous (classified) Locations.

Sensing Lines

- Small underground piping at Avista's installations is discouraged. It is preferred to use pressure transducers tapped from the main piping and route the signal cables in conduit to the RTU or communication box.
- Correctors and pressure recorders utilizing integral pressure transducers should be mounted as close to the meter or piping as practical to minimize the use of small diameter exposed tubing.

- Each sensing line should have a unique tap with 1/4-inch NPT female pipe threads for connection to sense line tubing adaptor.
- A shutoff valve must be installed in each takeoff line as near as practical to the point of takeoff. No taps off bottom of piping.
- Sensing lines should be located in the piping system to sense line pressures at a point of non-turbulent laminar flow. This generally is achieved by placing sensing taps a minimum of 10 pipe diameters downstream of any valves, regulators, or fittings. Sense line taps are typically located with the taps for the associated regulator sense lines.
- Site specific consideration should be given to adjusting the pressure sensing location to allow for maintenance of the tap without shutting down a single sourced system. Location of bypass regulators and manual bypasses should also be considered.
- Each takeoff connection and attaching fitting or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached and be designed to satisfactorily withstand all stresses without failure by fatigue.
- Isolation valves and tees supplied by Mercury Instruments in their installation kit or similar fittings procured separately should be used along with fittings to allow for calibration and a Ralston "check valve type Quick Test" fitting or similar approved fitting.
- Sensing lines should be 3/8-inch OD stainless steel tubing for mechanical strength except in the case of extremely short runs where the corrector or recorder is at the tap location such as on the meter.
- Fittings at the instrument connections should use dielectric insulators for electrical isolation from the gas piping and cathodic protection system.
- Sensing lines should be routed and secured above grade to provide protection from anticipated causes of damage.
- Valve handles should be removed or locked to prevent unauthorized operation.

Pulses to Customer

Avista may, upon customer request, provide metering pulses as described below for connection to an input to the customer's energy management system or to a remote totalizer.

The costs for these custom installations will be billed to the customer on a time and materials basis.

Customer connection and general information regarding pulses:

- The transistors or reed switches that provide output pulses from Avista's metering installations are designed for low voltage and low current control signal applications such as interfacing with electronic energy management systems. Ratings are listed below. They are not for controlling relays, solenoids, or lights.
- Manual local electrical isolation disconnect from the customers wiring should be provided by installation of a weatherproof MIL style connector set supplied and installed by Avista in series with the wiring from the customer near the meter. This is to protect Avista personnel working on metering from inadvertent voltages that could be present on the wiring from the customer and serve as a demarcation point.
- The customer is responsible for installation of conduit and wiring in accordance with requirements outlined by Gas Engineering and communicated by Avista's Metermen or Telemetry Technicians.
- Avista will make the connection to the meter's corrector or pulser.

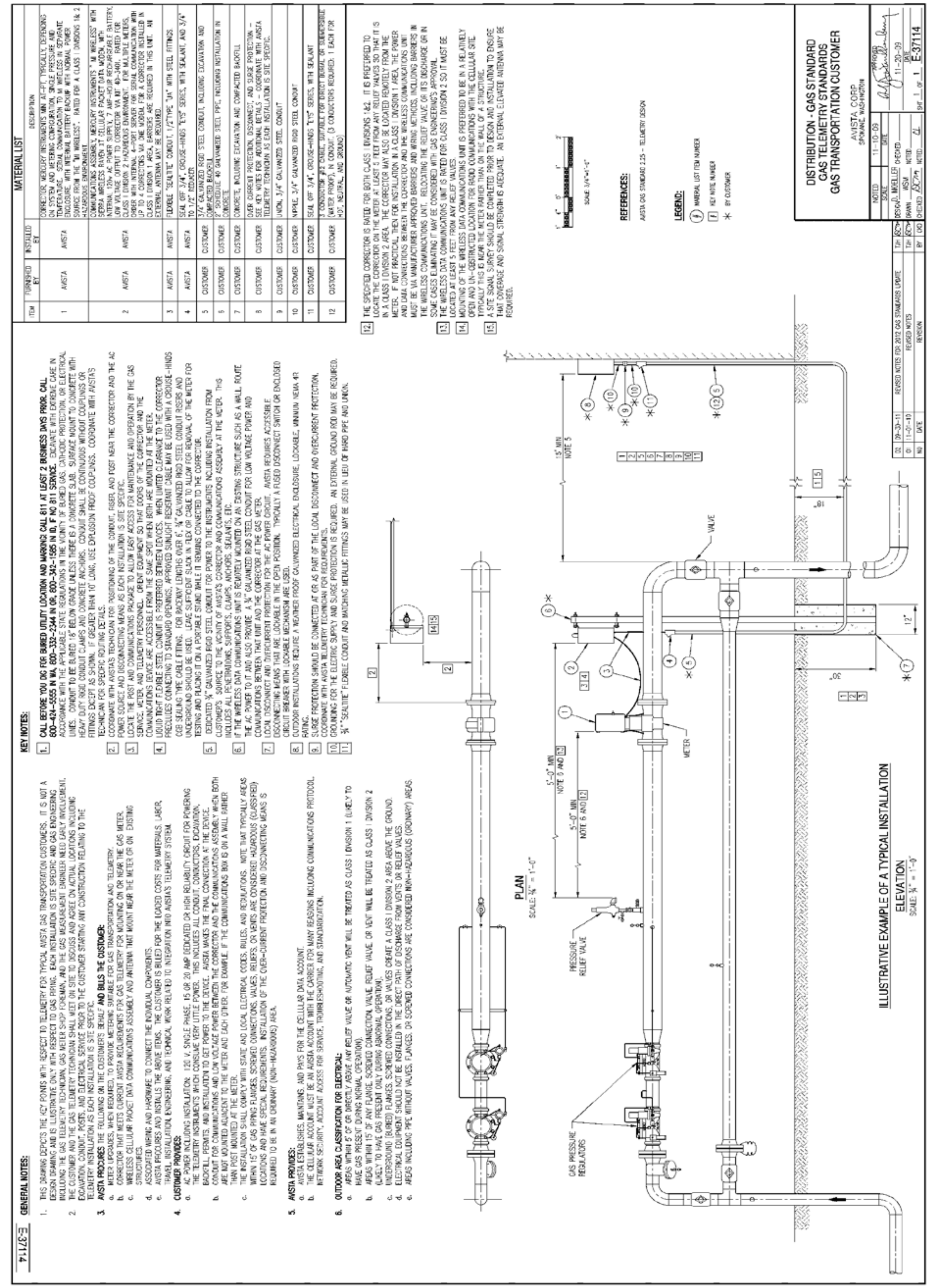
- Meters without electronic volume correctors:
    - Pulses should be provided by adding a magnetic volume pulser between the wiggler shaft and the mechanical index or replace the index with a combination index/pulser consisting of a commercially available reed switch and magnet unit that may provide 1, 2, 4, or 10 pulses per revolution.
    - The reed switch is rated for low voltage and current, typical for an electronic input.
    - These are dry contacts. The wetting voltage will be provided by the customer's energy management system.
    - Typical reed switch ratings are 30 VDC / 21 VAC, 0.025 amps maximum.
    - Acceptable pulsers include Miners & Pisani # MVP-10 and MVP-1; Honeywell / Mercury Instruments #206, 210, or 212; Miners and Pisani / Elster/American Meter #RVP-F1 52870K161, depending on the application.
    - Avista provides and installs the above pulsers and bills the customer.
- Meters with electronic gas volume correctors:
    - Corrected or un-corrected pulses, as determined by the customer's need and Avista's metering capabilities, should be provided from the electronic corrector's isolated pulse output.
    - The pulse output is typically an open-collector transistor rated for low voltage and current and is polarity sensitive: 3VDC min – 30 VDC max (DC only), sinking up to 0.015 amps for form C outputs and 0.005 A for Form A outputs. The wetting voltage will be provided by the customer's energy management system.
    - Avista provides and installs any additional components that may be required to obtain the isolated pulse output and bills the customer.
- Remote Volume Totalizers / Counters: Avista may furnish remote totalizers to make use of metering or corrector pulses to actuate a remote volume index for the customer. Costs are billed to the customer.
- Avista will define the volume of gas that each pulse represents. Avista will also define if it is an un-corrected reading (index or raw value and if it is temperature compensated) or a "corrected for temperature and pressure" value from an electronic gas volume corrector.
- <u>Disclaimer:</u> Pulses and reports furnished to the customer are not for billing purposes. They are local raw data and informational only. Future delivery and/or replacement data is not guaranteed. Avista makes no other representations or warranties concerning the pulses or data and there are no express warranties and no implied warranties pertaining to the data including, but not limited to, any warranty of merchantability or fitness for a particular purpose, all of which are hereby expressly disclaimed.

Transport Customers

Gas Transportation Customers: Refer to Drawing E-37114 Sheet 1, Gas Telemetry Standards, Gas Transportation Customer. The drawing is located at the end of this specification for typical installation details.

1. Avista procures the following on the customer's behalf and bills the customer:
    a. Meter upgrades, when required, to provide metering suitable for gas transportation and telemetry.
    b. Corrector that meets current Avista requirements for gas telemetry for mounting on or near the gas meter.
    c. Wireless cellular packet switched data communications assembly and antenna that mount near the meter or on existing structures.
    d. Associated wiring and hardware to connect the individual components.
    e. Avista procures and installs the above items. The customer is billed for the loaded costs for materials, labor, travel, installation, engineering, and technical work related to integration into Avista's telemetry system.

2. Customer provides:
    a. AC power including installation: 120 V, single phase, 15 or 20 amp dedicated or high reliability circuit for powering the telemetry instruments which consume very little power. This includes all conduit, conductors, excavation, backfill, permits, and installation to get power to the device. Avista makes the final connection at the device.
    b. Conduit for communications and low voltage power between the corrector and the communications assembly when both are not mounted adjacent to the meter and each other. For example, if the communications box is on a wall rather than post mounted at the meter.
    c. The installation shall comply with state and local electrical codes, rules, and regulations. Note that typically areas within 15 feet of gas piping flanges, screwed connections, valves, reliefs, or vents are considered hazardous (classified) locations and have special requirements. Installation of the over-current protection and disconnecting means is required to be in an ordinary (non-hazardous) area. Refer to Electrical Classification within this specification for additional details.
    d. If a wireless or cellular radio or modem is not practical such as when there is no reliable coverage, the customer must provide or continue to provide, at their expense, as is standard practice for existing customers:
        i. Dedicated standard voice grade telephone line with direct dialing in and out including long distance direct dial service that is available continuously.
        ii. Installation of Avista provided signal circuit protector for the phone line including grounding.
        iii. Installation of telephone cable to protector and to the penetration at the wall with enough extra cable for Avista to terminate.
        iv. Dedicated galvanized rigid steel conduit for telephone line including installation from customer’s wall penetration and interior junction box to the vicinity of Avista’s corrector at the meter. This includes all penetrations, supports, clamps, anchors, sealants, etc.
        v. If the telephone signal circuit protector is mounted outdoors, a locking box and ground rod are required.
3. Avista provides:
    a. Avista establishes, maintains, and pays for the cellular data account.
    b. The cellular account must be an Avista account with the carrier for many reasons including communications protocol, network security, and account access for service, troubleshooting, and standardization.
4. Notification and Timing:
    a. Avista’s Gas Engineering requires 90 days minimum notice from the date Avista receives “written notice” from the customer advising of their intent to sign a “Transportation Services Agreement”. This allows time to design, procure, install, test, and integrate the field devices into the Gas Telemetry System.
    b. Advice of this notice should be via e-mail either from the Natural Gas Resources Manager or the Account Executive to both the Manager of Gas Engineering and to the Gas Measurement Engineer.


E-37114
GENERAL NOTES:
KEY NOTES:
MATERIAL LIST
PLAN
ELEVATION
ILLUSTRATIVE EXAMPLE OF A TYPICAL INSTALLATION
GAS PRESSURE REGULATORS
PRESSURE RELIEF VALVE
METER
VALVE
REFERENCES:
LEGEND:
DISTRIBUTION - GAS STANDARD
GAS TELEMETRY STANDARDS
GAS TRANSPORTATION CUSTOMER
AVISTA CORP.
SPOKANE, WASHINGTON

2.3 CATHODIC PROTECTION

2.32 CATHODIC PROTECTION DESIGN

SCOPE:

To establish uniform procedures for the protection of metallic pipelines from external, internal, and atmospheric corrosion.

REGULATORY REQUIREMENTS:

§192.451, §192.452, §192.453, §192.455, §192.457, §192.459, §192.461, §192.463, §192.465, §192.467, §192.469, §192.471, §192.473, §192.45, §192.476, §192.477, §192.479, §192.481, §192.483, §192.485, §192.489, §192.490, §192.491

WAC 173-160-456, 480-93-110

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design - Steel
Spec. 2.13, Pipe Design - Plastic
Spec. 2.14, Valve Design
Spec. 2.15, Bridge Design
Spec. 3.12, Pipe Installation – Steel
Spec. 3.42, Casing and Conduit Installation

THEORY OF CORROSION:

AC vs. DC

Electrical current is classified as either alternating (AC) or direct (DC). Alternating current reverses its direction of flow many times each second. Direct current is line-directional in nature or flows in one direction only. Alternating current, for all practical purposes, is not related to the corrosion process.

In order to measure corrosion current, to determine cathodic protection current requirements, and to verify the adequacy of protection equipment installed, it is necessary to make measurements of DC current.

Corrosion Cell

Corrosion of a metal will only occur if all the following four are present: an anode, a cathode, an electrolyte, and an electrical connection between the anode and cathode. When all of these are present, we have a corrosion cell.

Corrosion or deterioration of the metal takes place at the anode where metal ions enter solution. When steel corrodes or oxidizes, the iron atom loses two electrons (e-) and the iron ion (Fe++) enters the electrolyte. The initial reaction produces a corrosion product, ferrous hydroxide, which is usually white in color. This product is often unstable and will combine further with available oxygen and water. The stable product formed is ferric hydroxide and it exhibits a characteristic brown or rust color.

Anode and Cathode Reactions

Anode Reaction:

$Fe^{++} + 2OH \rightarrow Fe(OH)_2$ Unstable Ferrous Hydroxide (White)
$4Fe(OH)_2 + O_2 + 2H_2O \rightarrow 4Fe(OH)_3$ Ferric Hydroxide or Rust

Cathode Reaction:

$2H^+ + 2e^- \rightarrow H_2$ Hydrogen Gas
$4H^+ + 4e^- + O_2 \rightarrow 2H_2O$ Water

An associated, simultaneous reaction occurs at the cathode and combines hydrogen ions (H+) with electrons (e-), which have been released from the anode, to form hydrogen atoms (H). This hydrogen then plates out on the cathode, combines with oxygen to form water, or combines with other hydrogen atoms and evolves off as molecules of gas (H2).

The formation of hydrogen on the cathode and oxide on the anode, polarization, tends to retard the corrosion rate. A chemical or mechanical process that removes either the protective hydrogen or oxide films will allow corrosion to continue.

The corrosion rate of the anode is directly proportional to the current density or current flow from the anode. Therefore, anything that can be done to stop or reduce this current flow will in turn stop or reduce corrosion. Corrosion and corresponding corrosion control are based on this principle. The basic means of corrosion control is first and foremost an effective coating installation, followed by the removal of either anode or cathode, breaking the electrical connection between anode and cathode, removing the electrolyte or increasing its electrical resistance, and the application of a counter protective current.

Anode-Cathode Area Ratio

The corrosion or penetration rate is also a function of the anode-cathode area ratios as follows (assuming a corrosion cell exists):

$$\text{Corrosion Rate} = \frac{\text{Cathode Area}}{\text{Anode Area}}$$

This relationship means simply that if a large cathode is connected to a small anode, the corrosion rate can be very severe. If the ratios are reversed, that is, a large anode connected to a small cathode, then the corrosion rate can be drastically reduced and, in many instances, will become negligible.

If perfect coatings could be applied to the anode or cathode, they would be electrically insulated from the electrolyte and all corrosion would stop. Since coatings are never perfect, coating the anode only will cause accelerated pitting where there are coating holidays due to the change in anode-cathode area ratios. Coating the cathode instead of the anode will more effectively reduce the corrosion rate without the danger of localized pitting. For practical reasons, since anodes and cathodes are not readily distinguishable on pipelines, both are given a coating.

Regardless of what metal is involved in a corrosion cell, the reaction at the anode and cathode is basically the same. The anode and cathode reactions occur simultaneously and cannot occur separately.

Electrolyte Resistivity

The magnitude of the corrosion current flowing between any anode and cathode is also dependent on the electrolyte resistance or resistivity. The greater the electrolyte resistivity the smaller the current flow, and conversely, the lower the resistivity the greater the magnitude of corrosion current.

Soil resistivity is sometimes classified as follows:

Resistivity (Ohm-cm)	Classification
0-1,000	Very Corrosive
1,000-10,000	Moderately Corrosive
10,000-Over	Slightly Corrosive

Corrosion classification of soils represents, in a very general way, a means of predicting areas in which corrosion of metals may become a problem. It is not proper to say that serious corrosion will occur because a specific resistivity is less than 500 ohm-cm or that corrosion will not occur because resistivities are above 10,000 ohm-cm. The corrosion classification of soils is still a useful tool to generally define corrosive areas if used within limits as a general guide to provide for better corrosion judgment.

Anode-Cathode Separation Distance

It is important to note that separation between anode and cathode exists more often than not on the same piece of pipe. The anode and cathode can be microscopically close or thousands of feet apart.

Anodes and cathodes are formed when metals are placed in dissimilar soils or electrolytes. These dissimilarities can be dissolved salts, moisture, temperature, or oxygen concentrations. Anodic areas will usually be in areas of greatest salt concentration, greatest moisture content, highest temperature, and lowest oxygen concentration. Oxygen concentration cells are common at mechanical junctions, in crevices, and under foreign deposits.

Dissimilar Metals

One of the most common types of corrosion is that caused by the junctions of two or more dissimilar metals. In cases where dissimilar metals are coupled together, one metal will corrode (anode) and have metal ions enter solution (electrolyte) and travel to the other metal (cathode). Metals are ranked by their tendency to corrode to each other in the following table known as the Galvanic Series.

Stainless steel and chromium are listed in two places in the series as both active and passive. When these metals are in an oxygen-starved environment, they have a greater tendency to corrode and are therefore placed higher in the series. When in a solution containing adequate or excess oxygen, stainless steel, and chromium are passive and are listed correspondingly toward the cathodic or protected end of the series.

The Galvanic Series

	MAGNESIUM ALUMINUM ZINC CADMIUM	Anode - Corroding End, Least Noble, Electro-Negative
	STEEL OR IRON CAST IRON CHROMIUM (ACTIVE) STAINLESS STEEL (ACTIVE)	
	SOFT SOLDER TIN LEAD	
	NICKEL BRASS BRONZE COPPER	
	SILVER SOLDER CHROMIUM (PASSIVE) STAINLESS STEEL (PASSIVE)	
Cathode - Protected End, Most Noble, Electro-Positive	SILVER GRAPHITE GOLD PLATINUM	

Stress Corrosion

Metals that have been stressed due to cold working, such as bending, threading, or riveting, will be affected by corrosion. The stressed area will normally be anodic to the adjacent non-stressed section.

CONTROLLING CORROSION

Direct current discharges from metal to the soil at all locations where corrosion occurs underground. Corrosion does not take place when current flows from soil to the pipe. One useful way of controlling corrosion is to stop the discharge current flow.

Insulation

Dissimilar metals in galvanic corrosion cells can be separated electrically by using insulated or dielectric fittings. The pipe itself can be insulated electrically from the soil electrolyte with the application of a nonconductive coating.

Metallic Coatings

Conductive or metallic coatings such as zinc coating or galvanized coatings are applied to base metal materials. Some of these applications are used underground but are usually more effective to combat atmospheric corrosion problems. When used underground the coated metal is protected by the preferential corrosion (galvanic series) of the metallic coating applied. The duration of protection is based on the thickness and uniformity of the coating applied, the difference in potential between the two metals (galvanic series), the soil resistivity, and at times the chemical composition of the soil.

Nonmetallic Materials

Plastic pipe (polyethylene) should be used where applicable. Plastic pipe is preferred for installations in intermediate pressure systems as it eliminates corrosion losses.

Change in Environment

Often the environment can be adjusted or altered to control or eliminate the presence of electrolytes. Select backfill can be used which provides drainage around the pipe and assures that sharp rocks do not damage pipe coatings. The ends of casings and conduits are sealed to assure that moisture is kept away from the pipe. Refer to Specification 3.42, Casing and Conduit Installation.

Allowances can be made in system designs to lessen velocities, cavitation, and pulsations that might break down protective films or oxides on inside walls of pipes.

Cathodic Protection

It is not economically feasible to design, apply, install, and maintain a coating that will completely insulate metal pipe from the soil electrolyte. Instead, the protection provided by an economical pipe coating is supplemented with the application of cathodic protection, an electromechanical method that forces the metal to become cathodic to its environment.

Galvanic System

Cathodic protection is applied galvanically by utilizing metals higher on the galvanic series such as zinc and magnesium and bonding them to the steel pipeline via a coated conductor. By causing metals higher on the series to become metallically part of the piping system, we cause these metals (sacrificial anodes) to corrode and afford protection to the steel pipeline. This application is usually limited to well-coated lines in lower soil resistivities.

Impressed Current System

In areas where current requirements are higher, impressed current protection systems be used. These systems normally utilize a rectifier which changes alternating current (AC) to direct current (DC) which then is caused to flow into the soil through an anode and ultimately to flow onto the pipeline thereby canceling all undesired corrosion current.

DESIGN AND INSTALLATION:

General

Newly installed metallic pipeline facilities must be installed with an Avista-approved coating that meets the requirements of §192.461 and must be cathodically protected within one year after installation. Refer to Specification 2.12, Pipe Design – Steel, “Pipe Systems Corrosion Protection” for specific coating requirements.

WAC 480-93-110: The state of Washington requires that new pipeline facilities must be protected within 90 days after installation.

The design, operation, installation, and maintenance of cathodic protection systems shall be carried out under the direction of a person qualified in pipeline corrosion control methods. Additionally, CP Deep Well design shall be done by a registered Professional Engineer if installed in Washington State (ideally NACE Level 4) and as a best management practice, such designs should be completed by a Registered PE in other Avista jurisdictions.

WAC 173-160-456 (2): Grounding wells shall be designed by an engineer, licensed in Washington State, trained in the design of corrosion protection wells.

Consult with a Cathodic Protection Technician before tying together or separating Cathodic Protection zones. Zones could be connected by adding steel main between other areas of steel main, or by connecting cathodic wires found at valves, regulator stations, and other sites. Zones could be separated when steel pipe is cut off and abandoned or through the separation or severing of cathodic wires found above or below ground.

Generally, new, and existing metallic piping systems are cathodically protected by Impressed Current Systems.

Anode Systems

Impressed Anode System Installation: Installation of an impressed current anode should be done with respect to remote earth. A good standard distance is 150 to 200 feet from the pipe. Anodes should be separated a minimum of 20 feet from a surface or traditional system. For a deep well, the top anode should be a minimum of 150 feet from the piping.

Galvanic Anode System Installation: Install galvanic anodes 3 to 5 feet from the pipe. Use a test station to connect the anode to the pipe. Two white lead wires should be installed on the pipe during the installation.

AC Mitigation

It may be necessary to provide AC mitigation systems on piping, which is closely parallel to or in close proximity to electrical transmission facilities or in areas where fault currents or unusual risk of lightning may be anticipated. A qualified Cathodic Protection Technician should review and recommend a design for AC mitigation. A mitigation system may include the following:

- Voltage gradient control mats at test stations, valves, and other pipeline appurtenances for personnel safety.
- Polarization cells connected between the pipeline and an AC ground such as a bare steel casing. These cells have a high resistance to DC and low resistance to AC.
- Periodic placement of zinc anodes for protection of the pipeline during phase –to-ground faults. In certain situations, paralleling the pipeline with zinc ribbon anodes may be recommended.

Test Leads

Test leads should be installed as discussed in Specification 3.12, Test Leads.

Tracer Wire

Insulated #12 solid coated locating wire installed with polyethylene pipe should be cathodically protected by installing a 4-1/2 lb. zinc anode approximately every 1,000 feet. Refer to Specification 3.13, Installation – Plastic Mains. Refer to Drawing A-36277, Wire Connections at the end of Specification 3.13, Installation – Plastic Mains.

System Isolation

Cathodic protection systems are to be designed and operated to minimize adverse effects on adjacent underground metallic structures.

Where stray currents from foreign cathodic protection systems are affecting Avista lines, corrective measures are to be taken to limit / eliminate the stray current condition.

Each pipeline must be electrically isolated from other underground metallic structures, unless the pipeline and the other structure are electrically interconnected and cathodically protected as a single unit. Care must be taken to assure that steel components within plastic pipe systems are not isolated unless it is planned to protect the steel as a single unit. Often it is desirable to utilize locating wire to provide cathodic protection to isolated steel components within the plastic pipe system (contact Gas Engineering in such cases as heavier gauge wire may be required). Wire connections to steel main or steel fittings shall be made by the "Cadweld" process. Refer to Specification 3.12, Cadweld Procedure.

Approved insulating devices must be installed where electrical isolation of a portion of a pipeline is necessary to facilitate the application of cathodic protection.

Each metallic pipeline must be electrically isolated from metallic casings. If isolation is not achieved because it is impractical, other measures must be taken to minimize corrosion of the pipeline.

Insulating devices may not be installed where a combustible atmosphere is anticipated unless precautions are taken to prevent arcing.

Replacing Steel Main

When replacing steel pipe (main) of any length, consult a Cathodic Protection Technician prior to considering conversion to polyethylene plastic (PE) pipe. Isolation of steel services and sections of steel main is a critical consideration and shall not occur without the permission of Gas Engineering.

The true replacement cost should be considered when replacing steel with PE. Such analysis should consider both the cost to replace in-kind with new steel (thereby preserving cathodic protection continuity) and the cost of replacing with PE (to include replacement of any steel services that will be isolated in the process and any related cathodic protection work needing to be done).

Replacing Steel Services

When replacing steel services of any length, consult a Cathodic Protection Technician prior to considering conversion to polyethylene (PE) plastic pipe.

The conversion to polyethylene (PE) plastic services should be the full length from the main to the meter for the betterment of the gas system to prevent isolated steel locations and disbonded dresser fittings. Refer to Specification 3.16, Services, "Steel Service Replacement" for further guidance.

2.4 VAULTS

2.42 VAULT DESIGN

SCOPE:

To establish a uniform procedure for designing vaults for regulator stations and valve assemblies.

REGULATORY REQUIREMENTS:

§192.183, §192.185, §192.187, §192.189

OTHER REFERENCES:

NEC Article 500
Standard Highway H-20 loading requirements

CORRESPONDING STANDARDS:

Spec. 5.18, Vault Maintenance

DESIGN REQUIREMENTS:

General

The use of vaults for valves or regulating stations should be avoided whenever possible. The confined space created by vaults can accumulate gas, restrict available room to maintain equipment, and are difficult to keep dry. Regulator stations should be constructed aboveground whenever possible.

Vaults shall be located in an accessible location that is away from street intersections or points where traffic is heavy. They shall not be located in close proximity to water, steam, electric, or other facilities. Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters should also be avoided when determining the location of a vault.

Each underground vault must be able to meet the loads which may be applied on it while protecting the equipment inside. Generally, vaults installed in traveled roadways must be designed to meet Standard Highway H-20 loading requirements.

Enough room must be provided within the vault to enable proper installation and maintenance of the equipment.

Each pipe entering or within a regulator vault or pit must be steel, except instrumentation and control lines, which can be stainless steel. Where pipe extends through the vault structure, provisions must be made to prevent the passage of gases or liquids through the opening, and to avert strain in the pipe. Polyethylene piping may not be used inside a vault.

Sealing and Ventilation

Each underground vault or closed top pit containing either a pressure regulating, or relieving station must be sealed, vented, or ventilated as follows:

- When the volume exceeds 200 cubic feet, the vault or pit must be ventilated with two ducts (one at bottom and one at top of structure), each having at least the ventilating effect of a pipe 4 inches in diameter and vents shall be positioned high enough above grade to disperse gas air mixtures that might be discharged. Ventilation must be enough to minimize the ability of a combustible atmosphere to develop within the vault

- When the volume exceeds 75 cubic feet, but is less than 200 cubic feet and the vault or pit is sealed, each opening must have a tight fitting cover, free of openings through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover.

- When the volume exceeds 75 cubic feet but is less than 200 cubic feet and the vault or pit is vented, the venting shall be designed to prevent external sources of ignition from reaching the vault atmosphere. Vents shall be directed away from potential sources of ignition.

- When the volume exceeds 75 cubic feet, but is less than 200 cubic feet and the vault or pit is ventilated, the ventilation shall be designed to conform to the requirements described for vaults with volumes in excess of 200 cubic feet unless the vault or pit is to be ventilated by openings in grates or covers and the ratio of internal volume (cubic feet) to the effective ventilating area (sq. in.) of the grate or cover is less than 20:1 in which case no additional ventilation is required.

- When the volume is less than 75 cubic feet, no ventilation is required.

Drainage

Each vault must be designed so as to minimize the entrance of water.

A vault containing gas piping may not be connected by means of a drain connection to other underground structures.

Electrical Code

Electrical equipment in vaults must conform to the applicable requirements of the National Electric Code (NEC) Article 500 for Hazardous (classified) Locations.

2.5 ODORIZATION

2.52 ODORIZATION OF NATURAL GAS

SCOPE:

To establish uniform procedures for odorizing natural gas.

REGULATORY REQUIREMENTS:

§192.625

CORRESPONDING STANDARDS:

Spec. 4.18, Odorization Procedures
Spec. 5.23, Odorization Equipment

ODORIZATION:

General

Natural gas in its natural state is odorless. A distinctive odorant is mixed with natural gas enabling it to be detected by a person with a normal sense of smell at concentrations well below that which would allow the natural gas to ignite.

Natural gas supplied to customers will be odorized. Natural gas will generally be odorized at or near the gate station except where such gas is adequately odorized as received from the interstate pipeline company.

Odorant Type

Only odorants approved by Gas Engineering shall be used to odorize gas distributed by Avista. Avista utilizes an odorant mixture comprised of 80 percent by weight tert-butyl mercaptan and 20 percent methyl ethyl sulfide.

In the concentrations in which it is used, the odorant in combustible gases must comply with the following:

- The odorant may not be harmful to persons, materials, or pipe.
- The products of combustion from the odorant may not be toxic when breathed nor may they be corrosive or harmful to those materials to which the products of combustion will be exposed.
- The odorant may not be soluble in water to an extent greater than 2.5 parts to 100 parts by weight.

Odorizer Types

Equipment for odorization must introduce the odorant without wide variations in the level of odorant. Three different types of odorizers are used to transfer odorant into the gas stream.

Wick Odorizer - This odorizer is used for very small flow applications (up to approximately 500 SCFH). It consists of a small one pint to 3 quart bottle that is fastened in-line with the gas flow. A wick extends from the bottle into the gas flow and odorant is transferred from the bottle to the gas via the wick. This type of odorizer is often referred to as a "domestic" odorizer.

Bypass Odorizer - This odorizer is used for the majority of odorization applications (up to approximately 4,000,000 SCFH). A very small portion of the total volume of natural gas to be odorized is bypassed through the odorizing unit where it is saturated with odorant vapor. The saturated gas is then reintroduced and mixed with the gas passing through the gas main. In the process of passing through the odorizing unit, the bypassed gas absorbs many times the amount of odorant required to provide the desired odor intensity, therefore only a relatively small volume of saturated gas need be mixed with the main gas stream. Gas is bypassed or drawn through the unit by a differential pressure created by placing a restriction in the gas line. The volume of bypassed gas can be fine-tuned with a restrictor valve.

Injection Odorizer - This odorizer is used for high volume applications and in locations where telemetry is available on site. Liquid odorant is injected by a pump or other mechanical means into the pipe where it is mixed into the gas stream as it flows through the pipeline. A computer operates the odorizer and determines the appropriate amount of odorant to inject based on the desired odorization level and the volumetric flow rate of gas in the pipeline.

Odorant Concentrations

Refer to Specification 4.18, Odorization Procedures, “Odorant Concentrations” for details on Avista’s odorization concentration procedures.

3.0 CONSTRUCTION

3.1 PIPE INSTALLATION

3.12 PIPE INSTALLATION - STEEL MAINS

SCOPE:

To establish a uniform procedure for storing, handling, and installing steel gas pipe systems which adhere to applicable regulatory codes and provide a safe, reliable gas system.

REGULATORY REQUIREMENTS:

§192.161, §192.233, §192.241, §192.243, §192.245, §192.307, §192.313, §192.315, §192.317, §192.319, §192.750

WAC 480-93-018, 480-93-160, 480-93-175

OTHER REFERENCES:

API Standard 1104
SSPC-SP-10 Near White Blast Cleaning
NACE Standard RP027A-98
ASME B31.8
ASTM A370

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design – Steel
Spec. 2.32, Cathodic Protection Design
Spec. 3.18, Dry Line Pipe
Spec. 3.22, Pipe Joining – Steel
Spec. 5.17, Reinstating Abandoned Gas Pipelines and Facilities

CONSTRUCTION REQUIREMENTS:

General

Personnel installing and inspecting steel pipelines and facilities shall be instructed, trained, and qualified with the equipment and procedures required to install steel pipe. Steel pipe shall be welded by personnel tested by Avista Pressure Controlmen.

As a best practice, prior to welding on existing high pressure (above 60 psig) steel pipelines, a Welder should try to verify the wall thickness of the pipe through available means such as recorded pipeline data, pipe stenciling, or a wall thickness tester.

Installations of steel pipelines and facilities shall be inspected on a sampling basis to ensure the work conforms to Avista standards, as well as to the applicable state, federal, and local requirements. The Inspector shall have the authority to order the repair, or the removal and replacement, of any component that fails to meet the above requirements.

Except for those situations noted in Specification 2.13, Pipe Design–Plastic (Polyethylene), Aboveground Plastic Pipe, pipe installed aboveground, in pits, or that passes through a wall shall be steel. Steel pipe installed aboveground shall be protected from vehicles or other hazards by placing at a safe distance or by installing behind barricades.

Steel pipe installed below ground must be protected from washouts, floods, unstable soil, landslides, or other hazards.

Considerations should be made to stop work activities on steel pipeline facilities when lightning is seen, thunder is heard, or a thunderstorm is in the forecast. This will help minimize the workers exposure to a possible shock hazard. Specific conditions should be discussed with the local Operations Manager for clarification.

Monitoring of Pressures

Gas personnel performing work on pipelines and facilities that could result in loss of pressure or overpressure to the system shall install accurate pressure gauges upstream and downstream of the work site. The pressure gauges shall be continuously monitored so that personnel can respond accordingly if system pressures are greatly affected.

Additionally, there may be times when merely monitoring downstream pressure may not be sufficient to prevent customer outages without further action. It may be necessary during warm days or periods of low gas use to intentionally draw down the pressure of the downstream system and observe it to confirm the existence of a looped system prior to altering the system or leaving the area. Consult Gas Engineering for recommendations prior to altering any system's pressure. It may also be necessary to install a temporary bypass if a system is not looped or if the pipeline work could result in loss of pressure to the system. Refer to "Temporary Bypass" subsection in this specification for temporary bypass details and requirements.

Any loss of pressure that may have extinguished pilots or that may have affected the normal operation of the customer's gas equipment shall be treated as an outage and the procedures followed as outlined in the GESH, Section 5, Emergency Shutdown and Restoration of Service.

Temporary Bypass

The installation of a temporary bypass may be necessary whenever gas personnel are performing main or service work that could result in loss of pressure to the system. Pressure gauges should be installed and monitored in accordance with the Monitoring of Pressures section of this specification whenever a temporary bypass is used. Gas Engineering should be consulted for bypass sizing, **except** in situations where **all** the following conditions are met:

- Pipeline being bypassed is 4" diameter or smaller.
- Bypass pipe or hose is ¾" diameter or larger.
- Bypass length is 25 feet or less.
- System MAOP is between 5 and 60 psig.
- Bypass has no more than two tie-in connections (i.e., two-way bypass)
- Average daily temperature on day of bypass is forecasted to be 65 degrees F or greater

$$T_{avg} = \frac{T_H + T_L}{2}$$

Where:

T_{avg} = Average daily temperature forecast on day of bypass, degrees F
T_H = High temperature forecast on day of bypass, degrees F
T_L = Low temperature forecast on day of bypass, degrees F

Storage and Handling of Pipe

Pipe must be handled carefully to prevent bending, denting, buckling, scratching, gouging, or other damage.

If coated pipe is to be handled with lifting equipment, use belts, slings, or padded forks to minimize damage to the coating. Metallic equipment shall not be allowed to come in contact with the coating.

Coated pipe 4 inches in diameter and greater shall be stored and/or hauled with flat wooden dunnage between each layer of pipe. The entire load must be adequately secured to prevent movement. Metallic tie-down equipment and/or lines shall be carefully padded.

Steel pipeline coatings are susceptible to damage from ultraviolet (UV) radiation. For this reason, it is recommended that yard stock be inspected periodically and rotated to maximize the coating life. Chalking or fading of fusion bonded epoxy and abrasion resistant overlay coatings is common for pipe that is exposed to UV radiation and does not indicate that the coating is compromised. The utilization of jeeping (refer to "Installation in Ditch" within this specification) is the preferred way to evaluate the condition of the pipeline coating prior to installation. Pipe coating with excessive weathering (cracking, etc.) should either be discarded or repaired with an approved coating.

The ends of pipe shall be sealed with end caps or other acceptable means to keep water and foreign objects out of pipe.

Stenciled markings on coated pipe shall be maintained until the pipe has been installed in the ground. If the pipe specification information cannot be verified, the pipe shall not be used as carrier pipe.

Visual Inspection

Visual inspection requirements apply to welding performed on a gas carrying system. Welds shall be visually inspected by an individual with the appropriate training and experience in visual inspection and qualified on Visual Inspection of the Weld (221.130.005) or Welding (221.130.010) or be a qualified welding inspector authorized by Avista. Visual inspections must be performed as per applicable section(s) of API Standard 1104. Refer to Specification 3.22, Joining of Pipe - Steel, “Non-Destructive Testing (NDT) Requirements”.

Under the following conditions for pipe that produces a hoop stress of 20 percent or more of specified minimum yield strength (SMYS), visual examinations of the welds by a qualified welding inspector may be substituted for non-destructive testing (NDT):

- The pipe has a nominal diameter of less than 6 inches regardless of stress level; or

- The pipeline operates at a pressure of under 40 percent of SMYS and the welds are so limited that NDT is impractical.

A waiver from Gas Engineering should be obtained to avoid NDT examination in either case.

Stringing

To prevent contact between the coating and the ground, it is preferred that pipe is supported on dunnage, sandbags, or other non-metallic objects that will not cause damage to the pipe coating. In areas free of sharp rocks and other objects that can cause damage to the pipe coating, pipe may be placed on the ground as long as the pipe is not drug across the ground.

Pipe shall not be strung on the right-of-way in rocky areas where blasting is probable until after the trench is completely shot.

Mastic Coating

Mastic coating, such as Royston Roskote R28 Rubberized Mastic, is a cold-applied coating with high electrical resistivity designed to protect underground steel pipe and fittings. Mastic may be used as a field applied coating for valves and other intricate objects that are difficult to wrap with tape or wax wrap. Mastic shall be applied per the manufacturer's instructions on the can.

Tape Wrap

Bare steel pipe and fittings shall be coated prior to burial to protect against corrosion. Avista primarily utilizes cold applied tape wraps for protecting bare steel pipe, weld joints, and smooth contoured fittings. Wax type tapes may be used for irregular shaped surfaces as they are more flexible and will provide better coverage when applied to sharp contours. Wax type tape is available for both below ground and above ground applications. Tape for above ground applications has a special backing that is both UV and weather resistant. Both cold applied and wax type tapes can be applied to steel materials with factory coating types including polyethylene X-Tru coat, FBE (Fusion Bonded Epoxy), and asphalt-based materials.

Cold Applied Tape Wrap

Cold applied tapes shall be applied in accordance with manufacturer's instructions including use of primer when applicable.

Bare steel to be tape wrapped shall be free of water, dust, dirt, grease, oil, and other foreign matter. At a minimum the surface shall be cleaned by either power or hand wire brushing. Grease and oil can be removed by use of a solvent. Surface to be coated should be wiped clean prior to tape application to verify removal of any residual dust or film from solvent cleaning. Moisture present on the surface shall be removed before coating.

Welds shall be cleaned of welding slag, splatter, and scale. Sharp edges or burrs shall be removed by grinding or filing.

Some cold applied tape materials are provided with in integrated primer (such as Tapecoat H35 and H50 Gray tape) and may be applied directly to the cleaned surface. A separate, additional primer is necessary when this tape is applied to materials at low temperatures (below 32 degrees F). When primer is required, it shall be applied and allowed to dry prior to application of the tape wrap.

Tape should be applied using the spiral wrap method with a minimum of 1-inch overlap between successive wraps. Wrap should overlap the factory coating by at least 4 inches. When taping pipe positioned in the vertical position the tape should be wrapped from the bottom up to create an overlap that does not allow moisture to accumulate at the overlapping tape joints.

Care shall be taken to minimize wrinkling of the tape wrap. A wrinkle may contain an air space between the tape and the pipe which may cause a corrosion concern. If a wrinkle occurs during the wrapping process, the wrinkle should be removed as much as possible by pushing down on the wrinkle to try and achieve bondage between the tape and the pipe. If an excessive wrinkle is present, the wrinkle shall be cut out and new tape wrap applied.

When taping pipe that is oriented horizontally, ensure that the wrap is terminated on the downhill side of the wrapping process. This minimizes the chance or water getting between the tape and the pipe surface.

Coating on Steel Risers

Ultraviolet (UV) resistant coatings on steel (carrier pipe) risers shall come above final grade by approximately 2 inches to protect the steel at the soil-to-air interface.

X-Tru coating may not be used for the above ground portion of steel risers (or for any above ground pipe) without a supplementary over coating because the X-Tru coat may degrade with UV exposure. Above ground wax tape is the preferred over coating for X-Tru coat in aboveground applications. Existing risers may be left with X-Tru coating if the coating is not cracked or degraded and covered with a well bonded gray enamel paint. Cracked and degrading X-Tru coating can lead to water pooling and subsequent corrosion and must be repaired with above ground wax tape.

Wax Type - Tape Wrap

Petrolatum or “Wax Type” tapes shall be applied in accordance with manufacturer’s instructions including use of a primer.

Bare steel to be tape wrapped shall be free of dust, dirt, grease, oil, and other foreign matter. At a minimum the surface shall be cleaned by either power or hand wire brushing. Grease and oil can be removed by use of a solvent. Surface to be coated should be wiped clean to verify removal of any residual dust or film from solvent cleaning. The primer exhibits preferential wetting and will displace moisture on the surface when properly applied. To assist in application excessive surface moisture should be removed prior to primer application.

Primer is to be applied by hand to a minimum thickness as specified by the manufacturer’s instructions to ensure preferential wetting and continuous application. Primer should be used to fill any voids or gaps prior to application of the wax tape.

Wrap the wax tape in a spiral wrap method with a minimum of a 1-inch overlap. Wrap should overlap the factory coating by at least 4 inches. Press and form the tape so there are no air pockets or voids. When taping pipe positioned in the vertical position the tape should be wrapped from the bottom up to create an overlap that does not allow moisture to accumulate at the overlapping tape joints. Press and smooth lap seams to ensure they are properly sealed. Underground applications may be backfilled immediately.

Repair and Patching Using Tape Wrap

Tape wrap may be used to repair damage in factory applied coatings or “holidays”. To repair the damaged coating, remove loose or non-bonded material. Prepare the surface of the pipe as listed previously. No sharp points, burrs, or rough edges shall appear around the factory coating edges. Sharp edges shall be feathered smooth prior to application of the tape.

Tape should be applied in a continuous circumferential wrap. Repair tape coating shall overlap the adjacent undamaged factory coating a minimum of 4 inches. The tape shall be worked down onto the surface of the steel so as to leave no wrinkles or voids appearing on the view surface of tape that is in contact with the steel.

Repair and Patching Using a Coating Patch

A coating patch may be used to repair damaged coatings or holidays. Prepare the surface of the pipe by removing dust, dirt, grease, oil, loose particles, and moisture. Use either power or hand wire brushing to clean the surface. Use a solvent, if necessary, to remove grease or oil. Wipe the surface dry. Install the coating patch by applying pressure to the entire patch area to ensure complete adhesion to the pipe surface. The patch should overlap the undisturbed pipe coating by a minimum of 1 inch. Multiple coating patches can be used if necessary.

Field Pinhole Repair

On new factory-applied coatings a pinhole holiday may be tape coated with a minimum of four inches of tape coat and primer or covered using a coating patch. Alternatively, a ScotchkkoteTM hot melt patch compound (226P Green) may be used. When using the hot melt compound, follow manufacturer's recommended application procedures. Existing piping pinholes may be tape coated with a minimum of a 4 inches square section of tape coat and primer when it is impractical to complete a full circumferential wrap.

Liquid Epoxy Coating

Liquid Epoxy Coating can be used to repair damage, holidays, or coat weld joints in Abrasion Resistant Overlay (ARO) coated pipe when it is to be installed by boring.

Liquid Epoxy Coating shall be Powercrete R95, or as specified by Gas Engineering, and shall be applied in accordance with the manufacturer's instructions.

Installation of Powercrete R95 shall be applied using the minimum application steps:

1. Ensure the pipe is clean of grease, oil, salts, and other contaminates. Acetone or other suitable solvent may be used to clean the pipe.

2. Abrasive-blast clean the surface to a near white (SSPC-SP-10) using a particle blast of non-crystalline silica material. Crystalline silica material may not be used due to possible health concerns. A "Bristle Blaster" or similar mechanical method of preparing the pipe surface is also acceptable as long as a near white surface cleanliness is achieved. A wire wheel is not an approved method for surface preparation and may lead to incomplete bonding of the coating.

3. Mix Parts A and B thoroughly and apply to dry and clean pipe using plastic paddles to a uniform desired thickness, typically 60-80 mils or on butt weld joints above the circumferential weld height. The coating is only to be applied to pipe in which the temperature is above the dew point to ensure no moisture is present. If necessary, the pipe may be preheated to remove moisture and speed the cure time. Refer to the table below:

LIQUID EPOXY CURING TIME		
Product	**Temperature in Degrees F**	**Min. Cure Time ***
Powercrete R-95	77	6.75 hours
	80	5.5 hours
	100	1.5 hours
	120	45 minutes
	176	26 minutes
	212 (Max Substrate Temperature)	23 minutes

*The temperature of the pipe must be maintained for the duration of the cure to meet the minimum cure times specified.

Abrasion Resistant Overlay Wrap

Abrasion resistant overlay wrap, such as Scar-Guard, can be used as an abrasion resistant overlay on field joints and pipe that will be installed by trenchless installation methods, such as horizontal directional drilling. The product uses a fiberglass cloth that is pre-impregnated with water-activated resin. This type of wrap must be installed directly over a corrosion protective coating such as cold applied tape wrap or liquid epoxy coating, and cannot be applied as a standalone anticorrosion coating.

Installation of Scar-Guard shall be done according to the following steps:

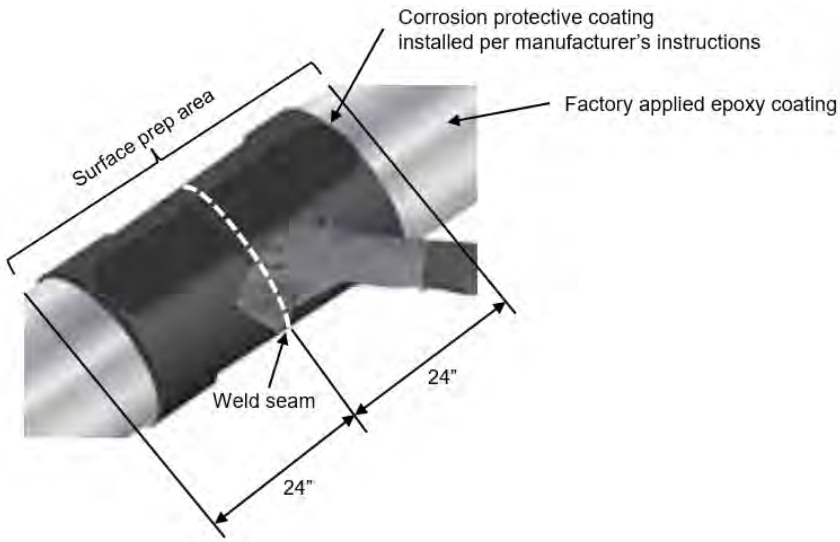
1. Install the corrosion protective coating such as cold applied tape wrap or liquid epoxy coating (see subsections Cold Applied Tape Wrap or Liquid Epoxy Coating for installation details). Use of liquid epoxy coating underneath the abrasion resistant overlay wrap should be considered in extremely rough ground conditions.

   The following installation instructions are specific to using cold applied tape wrap as the corrosion protection coating. If a liquid epoxy coating is used as the corrosion protection coating, refer to the manufacturer's installation instructions.

   Do not remove Scar-Guard from its packaging until step 4.

2. Surface preparation for Scar-Guard: The surface preparation area extends a minimum of 24" on both sides of the weld. Perform an SSPC SP1 solvent cleaning. Remove all visible signs of oil, grease, dust, dirt, or other surface contaminants. Clean the corrosion protection coating and the adjacent pipe coating with a solvent cleanser.

3. Abrade the area extending 24" on both sides of the weld with 60-80 grit sandpaper. Blow off, wipe down, or brush off the entire abraded area once preparation is complete to remove dust. Perform an electrical inspection of the prepared area to check for holidays (refer to subsection Electrical Inspection of Pipeline Coatings (Jeeping)).



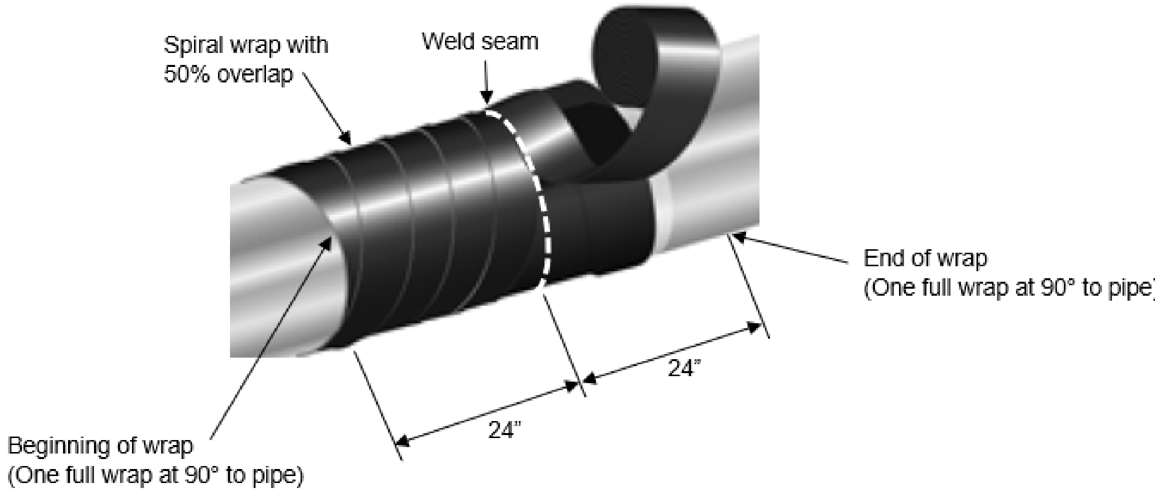
4. Important PPE equipment: Impermeable gloves shall be worn throughout the duration of steps 4 and 5.

   Steps 4, 5 and 6 must be completed within the allotted working time as specified in the table in step 7.

   After surface preparation has been completed, soak the entire area to be wrapped with water. Open the foil pouch and remove the roll. Begin the application a minimum distance of 24" from the weld. Scar-Guard must be wrapped in the correct orientation as shown below. The "zig-zag" side of the Scar-Guard must face outward towards the installer. The straight side must contact the pipe's surface.

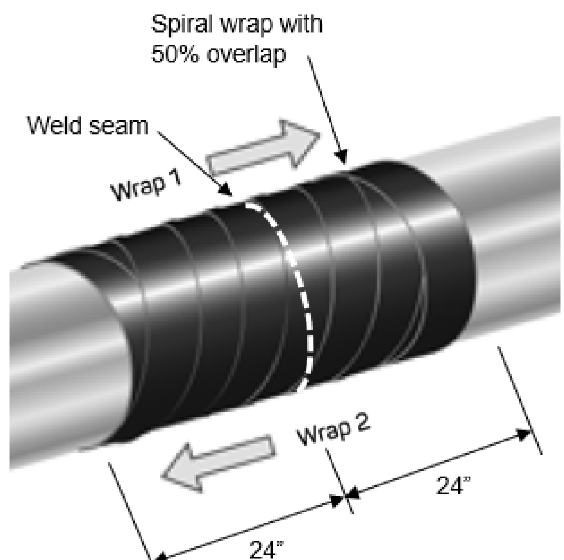
Zig-zag side faces the installer   Straight side faces the pipe

   Installation can start on the leading or trailing edge. Apply the first wrap circumferentially around the pipe at a 90° angle, then begin spiral wrapping with a 50% overlap towards the other edge. Apply tension during application by pulling firmly on the roll as it is applied. Squeeze and mold firmly in the direction of the wrap until tight. THOROUGHLY SOAK each layer (both sides, top, and bottom) of the Scar-Guard as it is being applied, not just the outer layer. Continue with the 50% overlap until the Scar-Guard extends a minimum of 24" past the weld. Scar-Guard is applied in a minimum single pass with 50% overlap to achieve a 2-layer system. End with a minimum of one complete circumferential wrap at a 90° angle.



Standard 2-layer application

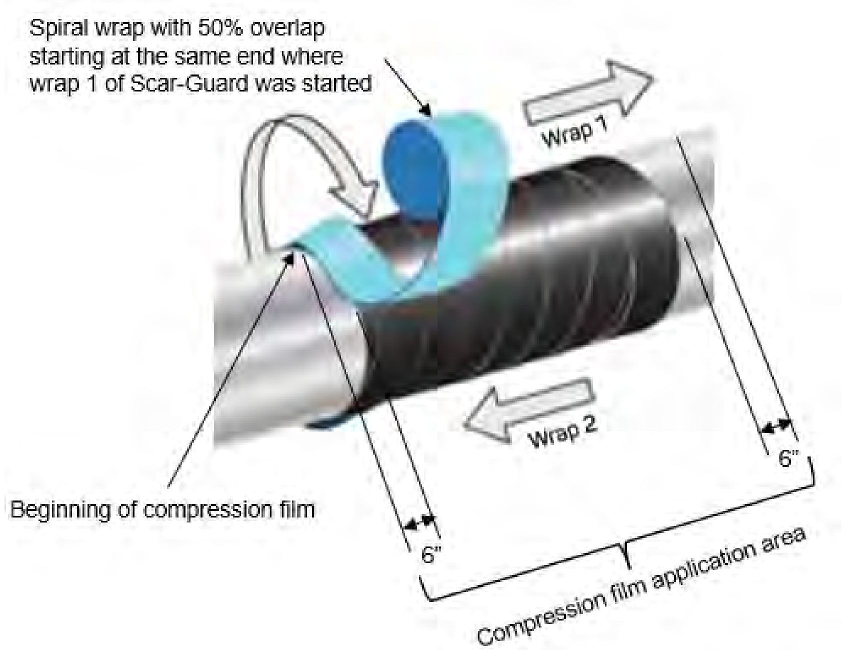
If rough ground conditions are expected, Scar-Guard can be applied in two wraps to achieve 4-layers of protection. Install the first wrap as described in step 4, then switch directions and continue to spiral wrap with a 50% overlap back towards the edge where the installation started.



Optional 4-layer application

5. Apply the compression film immediately after the Scar-Guard has been installed. Apply the compression film starting at the same end where wrap 1 of Scar-Guard was started and with a 50% overlap. Start a minimum of 6" beyond the outer edge of the Scar-Guard, pulling firmly during application to compress all Scar-Guard layers together, and end 6" past the Scar-Guard on the opposite edge. The compression film must be installed with a minimum of 4 layers thick (2 passes at 50% overlap). Apply compression film with high tension.

NOTE: Compression film should be applied before excess foaming is observed and the resin has exceeded the working time (refer to the table in step 7). The compression film must be applied and perforated immediately after the installation of the Scar-Guard.



6. Perforate the compression film using the perforation tool immediately after installation of all the layers. Use enough downward force to perforate the compression film ONLY. Leather gloves should be worn during this step. Perforation allows the CO_2 gas generated by the curing process, and excess water, to escape. During curing the material will foam slightly and some of the foam will rise through the perforations. Compression film should remain in place as long as possible, and should only be removed prior to installation of pulling the pipe in. The film will help protect the Scar-Guard from UV degradation should the pullback be delayed.

7. Allow Scar-Guard to reach a Shore D hardness of 60 prior to installing the pipe. Shore D readings should only be taken in flat areas. Shore D readings taken over grooves, resin poor fibers or foamed resin areas may result in lower values. Alternatively, rather than measuring Shore D hardness, Scar-Guard may be allowed to cure for the minimum amount of time listed in the table below before installing.

   Table definitions:

   Working Time – The maximum time allowed from when the Scar-Guard package is opened until the compression film is installed and perforated.

   Cure Time – The minimum time to achieve a Shore D hardness of at least 60 without the need to measure the Shore D hardness.

Scar-Guard Cure Times with Water		
Pipe Temperature (°F)	Working Time (minutes)	Cure Time (minutes)
39	5	100
75	4.5	65
90	4	75
150	3.5	80

Scar-Guard Cure Times with 35% Propylene Glycol Solution (Used in below freezing conditions)		
Pipe Temperature (°F)	Working Time (minutes)	Cure Time (hours)
15	20	24
23	25	24

Installation in Ditch

Coating must be inspected prior to lowering the pipe into the ditch and any damage found must be repaired prior to backfilling.

In addition to visual inspection, high pressure distribution pipelines shall be electrically inspected using a holiday detector, jeeping machine, or similarly tested to assure no flaws are present in the coating.

The steel pipe shall be installed in the trench with enough flexibility to prevent excessive stress from thermal expansion or contraction. Anchors or supports shall be provided to prevent undue strain, resist longitudinal forces, and prevent or damp out excessive vibration. Exposed pipe joints must be protected from any end forces caused by internal pressure, thermal expansion or contraction, and weight of pipe.

For transmission pipelines with 1,000 feet or more of continuous backfill, promptly after backfilling (but not later than 6 months after placing the pipe in service), a coating damage assessment shall be performed to ensure the integrity of the coating. The assessment may be performed using Direct Voltage Current Gradient (DCVG), Alternating Current Voltage Gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. The coating survey must be conducted in all locations except those where effective coating surveys are precluded by geographical, technical or safety reasons.

- If an alternative assessment method (other than DCVG or ACVG) is desired, PHMSA must be notified at least 90 days in advance in accordance with 192.18.
- Any coating damage classified as severe (voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) must be repaired in accordance with Section 4 of NACE SP0502 within 6 months after the pipeline is placed in service, or as soon as practicable after obtaining necessary permits, not to exceed 6 months after receipt of permits.
- Records of the coating assessment findings and remedial actions must be retained for the life of the pipeline.

Test Leads

Test leads are to be installed at the following locations to enable cathodic protection monitoring and locating:

- New steel main installations at approximately 1,000-foot intervals when possible or as needed.
- As close as possible to bore entrance and exit points of bores extending under a river, road, or other location in which the installed pipe depth is greater than standard installations.
- Both sides of buried insulated fittings. Refer to Drawing A-35447 and Drawing B-36271 at the end of this Specification.
- Steel casings with steel carrier pipe. Refer to Specification 3.42, Casing and Conduit Installations, Drawing B-34947 for details.
- On steel pipelines, where they cross other metallic pipelines. Additional test leads should be attached to foreign pipelines if consent can be obtained.

Test leads are normally a #10 white or black wire. The #10 wire may be either a solid or stranded wire. White wires shall be used on the pipe at each location where isolation or casings are not encountered.

Test leads are to be attached to steel mains or fittings by the "Cadweld" process. Reference the Cadweld Procedure within this specification. Joining and splice connections shall be either encapsulated in a dielectric type gel connector which is the preferred method, or a crimped sleeve covered by an approved dielectric sealing compound (such as Aqua-Seal) and tape wrapped. Prior to installing wires into an encapsulated connector, the wires should be tied together with an over-the-hand type knot approximately 6 inches to 12 inches from the end of the wires. This knot alleviates strain on the wire connection. Refer to Drawing A-36277, Wire Connections at the end of Specification 3.13, Installation – Plastic Mains.

The test leads shall terminate in a suitable, accessible, and convenient location near the transition point such as a test box or valve box. Refer to Drawing B-36271 for detail.

CADWELD PROCEDURE:

Before performing a Cadweld the pipe must be inspected to ensure the absence of defects, corrosion, mechanical damage, or other anomalies. Refer to the "Non-Destructive Pre-Inspection" section in Specification 3.22, Joining of Steel Pipe, for further guidance.

Select the correct Cadweld mold. There are two different types to choose from. The mold with the flat bottom is used only on 4-inch and larger diameter pipe. The mold with a concave bottom is used only on 3/4-inch to 3-1/2-inch pipe.

Inspect the Cadweld tool and ensure it is in good working condition. Ensure the ignition controller is in good condition and has batteries installed. If the light does not illuminate, the batteries are likely expired and will need replacing.

Identify the size of wire being used. The largest wire to be used with either mold is #8 (without a sleeve) or #10 and #12 which both require a sleeve.

Remove coating from the pipe surface using either an electric grinder or a sanding tool such as a file or a wire brush. An area no larger than 2 inches x 2 inches will be required. The pipe surface should be bright and clean of debris. At this point, fill out an Exposed Piping Inspection Report form (Form N-2534).

Strip enough coating from the #10 and #12 wires to accommodate a sleeve. Leave 1/8-inch exposed through the end of the sleeve. (A slight crimp may be used to hold the sleeve in place). Leave 1/8-inch of the sleeve exposed when inserted into the mold. For #8 wires, a sleeve is not required. Strip enough coating back to leave 1/4-inch of the wire exposed when placed into the mold.

Prior to loading the cad welder or performing the Cadweld, you must preheat the mold and pipe to eliminate moisture.

Load the Cadweld mold with the approved metal cup. Be sure to remove the clear plastic from the metal cup prior to loading. The cup should be labeled "CA-15" and have a green top.

Connect the ignition controller termination clip to the metal cup. The black line on the metal cup that indicates when the metal cup is fully installed.
Perform the Cadweld by holding the button on the ignition controller. The light will blink 5-10 times during the welding procedure. (Do not move or flinch during the Cadweld process as this may cause a substandard weld.)

Loop the wire around the pipe to relieve any potential stresses on the Cadweld.

Use a brass hammer to verify the quality of the weld. Remove any slag from the weld site using a wire brush.

If a poor Cadweld is performed, remove the debris, and move a minimum of 6 inches and return to Step #4 above.

When Cadwelding multiple leads to a pipe, ensure they are installed a minimum of 6 inches apart.

Coat the Cadweld and bare pipe with a company approved coating.

Bring wires up into the appropriate test box. Refer to Drawing B-36271 for test lead details across isolation fittings or transition fittings. Refer to Drawing B-34947 for casing test lead details. (Test leads may be either solid or stranded.)

Any questions about the configuration of wires can be referred to the local Cathodic Protection Technician.

Caution Tape

Except for horizontal directional drilling (HDD) installations, high pressure steel pipelines shall be installed with yellow warning tape stating words to the effect "CAUTION, GAS LINE BURIED BELOW" placed approximately 1 foot above the main.

The use of caution tape should also strongly be considered for intermediate pressure pipelines. These types of locations may include but are not limited to installations within private easements and dry-line installations where the presence of a gas pipeline may be unexpected to excavators.

Marker Balls

Marker balls should be installed at stopper fittings, bottom-out fittings, side-out fittings, ends of main, valves, stubs, and in other applicable instances in order to facilitate finding these fittings and locations in the future. Ensure as-built drawings and the resulting mapping records are updated to indicate the presence of these locating devices. Marker balls shall be installed with a minimum of 4 inches of vertical clearance to the buried gas facilities. The marker ball cannot be buried deeper than 4 feet from finish grade to allow for accurate locating. Considerations shall be made to install additional marker balls for facilities at depths, or anticipated depths, greater than 4 feet: one being placed near the buried facility and another being no more than 4 feet deeper than finish grade, or no deeper than 1 foot from finish grade for areas where seasonal snowpack occurs.

Dry Line Installations

As a general rule, dry line gas lines should not be installed unless there is a high degree of certainty that the line will be placed into service within three years. Additionally, consideration should be given to abandoning dry lines that have been in place for five years or greater to lessen the burden of ongoing locating of the facility. If the need arises to bring a former dry line into service that has been abandoned, it can be done in accordance with Specification 5.17, Reinstating Abandoned Gas Pipelines and Facilities. Refer to Specification 3.18, Dry Line Pipe, for additional details on pressure testing of dry line pipe.

Electrical Inspection of Pipeline Coatings (Jeeping)

An electrical inspection (commonly referred to as jeeping) is a test of the continuity of protective coating that should be performed on steel pipe prior to underground installation. It detects bubble or blister-type voids, cracks, thin spots, and foreign inclusions or contaminants in the coating that lowers the electrical resistance (dielectric strength) of the coating significantly. Manufacturer's recommendations should be followed on the use and maintenance of the equipment.

Excessive moisture or any electrically conductive material in or on the surface of the coating system can cause appreciable leakage currents, which may lower the effective testing voltage or cause erroneous holiday indication. Drying and cleaning of the coated surface may be necessary. Holiday detector parts shall be kept clean and free of moisture at all times.

The voltage setting on the equipment should be adjusted to match the coating. Thin film coatings up to 20 mil thickness require a low voltage detector. Thicker film coatings greater than 20 mil thickness require the use of a high voltage detector. Piping coating should be jeeped immediately prior to installation in trench. This will ensure that damage to the coating does not happen after jeeping is completed from vandalism or other occurrences while the pipe is unattended.

Voltage Settings for Conventional Coatings

The minimum testing voltage for a particular coating thickness shall be within 20 percent of the value determined from one of the following formulas or as shown in Table 1 as recommended by NACE Standard SP0188-2006.

$$\text{Testing Voltage} = 1{,}250 \times \sqrt{\text{coating thickness (mils)}}$$

Or

$$\text{Testing Voltage} = 7{,}900 \times \sqrt{\text{coating thickness (mm)}}$$

TABLE 1

Minimum Testing Voltage for Conventional Coating Thicknesses Such as X-Tru Coat*

mm	(in)	(mils)	Testing Voltage
0.51	N/A	20	5,600
0.79	N/A	31	7,700
1.0	N/A	40	7,900
1.3	N/A	50	8,800
1.6	N/A	62	9,900
2.4	3/32	94	12,000
4.0	5/32	156	16,000
4.8	3/16	188	17,000
13.0	1/2	500	28,000
16.0	5/8	625	31,000
19.0	3/4	750	34,000

**Thin-film coatings (fusion bonded epoxy) are not covered in this table.*

Voltage Settings for Thin Film Coatings (FBE)

The following formula shall be used to determine the voltage setting for thin film coatings such as fusion bonded epoxy (FBE):

Testing Voltage (TV) = 127 x mil thickness

Example: mil thickness = 16 mils
TV = 127 x 16 mils
TV = 2,032 Volts

Voltage Settings for ARO Pipe

The following formula shall be used to determine the voltage setting for FBE coated pipe with an additional ARO (Abrasive Resistant Overlay) coating:

Testing Voltage (TV) = (127 x mil thickness of FBE) + (1250 x $\sqrt{(\text{mil thickness of ARO})}$)

Example: FBE mil thickness = 16 mils
ARO mil thickness = 40 mils

TV = (127 x 16) + (1250 x $\sqrt{40}$)
TV = 9,938 Volts

Coating Thickness for New Pipe

The following table is provided as a reference for typical X-Tru coat and Fusion Bonded Epoxy Coating thickness on new pipe. The coating thickness is designed to maintain sufficient strength to resist damage due to handling (including, but not limited to, transportation, installation, boring and backfilling) as well as soil stress

TABLE 2

New Pipe Coating Thickness Table

Pipe Size (in)	**X-Tru Coating Thickness** (in)	(mils)	**FBE Coating Thickness** (mils)
1/2	.025	25	14 – 18
¾	.025	25	14 – 18
1-1/4	.025	25	14 – 18
2	.030	30	14 – 18
4	.035	35	14 – 18
6	.040	40	14 – 18
8 to 20	.040	40	14 – 18

Supports

Supports or anchors must be made from a durable material such as steel and/or concrete. No wood supports or anchors shall be used.

Supports or anchors should be mechanically attached to carrier pipe and cathodic isolation should be provided between the supports or anchors where needed. Supports or anchors shall not be welded to the carrier pipe.

Pipe Bends

Pipe inflections or changes in direction may be completed using appropriate bending equipment. Bends shall be free from buckling, cracks, or other evidence of mechanical damage. Bends shall not impair the serviceability of the pipe. Wrinkle bends are not allowed.

When bending pipe containing a longitudinal weld, the longitudinal weld shall be near as practical to the neutral axis of the bend.
The bend radius shall be no smaller than allowed by ASME B31.8 and as summarized in the following table:

Minimum Steel Bend Radius	
Nominal Pipe Diameter (D) (in)	Minimum Radius of Bend in Pipe Diameters (in)
Less than 12	18 x D*
12	18 x D
14	21 x D
16	24 x D
18	27 x D
20 and greater	30 x D

** Note: Shorter radius bends may be permitted provided the completed bend meets the serviceability criteria and the remaining wall thickness after bending is not less than the minimum design wall thickness. Contact Gas Engineering for assistance.*

Bends should be positioned at least 6 pipe diameters from the end of the pipe or a girth/circumferential weld. Bends and bending equipment shall be positioned so as to not affect the roundness at the ends of the pipe or stress the circumferential weld. No bends are allowed in girth welds.

Note that minimum steel pipe bend radius in this section are not to be confused with minimum bend radius of pipe for horizontal directional drilling and trenchless installation. Refer to Specification 3.19, Trenchless Pipe Installation, for information with regards to minimum allowable bend radius during trenchless installation.

Mitering/Segmenting Elbows

Welding elbows may be cut into segments to provide proper angle. Segments of elbows 2 inches or more in diameter must be at least 1-inch across the crotch (throat).

Pigging of Pipe

For large jobs or jobs installed during wet weather, it is possible that water and debris may need to be removed from the pipeline. Pigging should be considered at the discretion of the Avista project engineer, foreman, or inspector.

The pig launcher and receiver must be equipped with a device capable of safely relieving the pressure inside the launcher and receiver before inserting or removing in-line devices. An operator must use a device to either indicate that the pressure has been relieved or prevent opening of the launcher or receiver if the pressure has not been relieved.

Pits and Vaults

For any steel mains installed in association with a pit or vault, refer to Specification 2.42, Vault Design.

Odorizing Newly Installed Pipe

Newly installed pipe may present challenges with regards to meeting the required detection levels as defined in Specification 4.18, Odorization Procedures. New pipe, especially that which is gassed up but not immediately put into service, tends to absorb odorant in the pipe wall. Consideration should be made to “pickle” such pipe per Specification 4.18, Odorization Procedures, “Pickling Newly Installed Pipe.”

Moving or Lowering Steel Pipe in Service

Moving (or lowering) of steel pipe in service shall be performed only after careful consideration of various factors that might cause additional stress on the pipeline. Steel pipe with mechanical joints, threaded joints, or monolithic fittings (ex. Zunt) may not be moved due to the potential for a leak to develop at these locations. (Refer to the “Steel Pipe Lowering Decision Flow Chart” at the end of this Specification.)

When a small amount of pipe movement is required, the table below may be used to determine the minimum roping distance on both sides of the moved pipe section. This minimum roping distance will allow the pipe to move while keeping the stress level at an acceptable level. This table may only be used for pipelines 2 inches and smaller, that operate at 60 psig or less, and require 3 inches or less of movement.

Minimum Roping Distance on Both Sides of the Moved Pipe Section (MAOP = 60 psig or less)							
Nominal Pipe Size (Steel Pipe (inches))	Pipe Deflection (inches)						
	¼	½	1	1-½	2	2-½	3
1/2	3 ft	4 ft	5 ft	6 ft	7 ft	8 ft	9 ft
3/4	3 ft	4 ft	5 ft	6 ft	7 ft	8 ft	9 ft
1	3 ft	4 ft	6 ft	7 ft	8 ft	9 ft	10 ft
1-1/4	3 ft	5 ft	7 ft	8 ft	9 ft	10 ft	11 ft
1-1/2	4 ft	5 ft	7 ft	9 ft	10 ft	11 ft	12 ft
2	4 ft	6 ft	8 ft	10 ft	11 ft	13 ft	14 ft

Steel pipelines that require greater than 3 inches of movement, operate above 60 psig, or are greater than 2-inches nominal diameter must have roping calculations performed to determine whether moving will cause an unsafe condition. Roping calculations take into consideration the required deflection of the pipeline, existing pipe specifications, operating pressures, terrain, class location, present condition of the pipe, anticipated stresses, and the toughness of the steel. Consult Gas Engineering when a roping calculation is needed.

It is a requirement in Washington State to leak survey a gas facility within 30 days after being moved if the pipeline is intermediate pressure and 2 inches diameter or less. For other states and facilities, this is a best management practice. If leaks, flawed welds, or unsatisfactory workmanship are discovered when the pipe is exposed for moving, they shall be repaired prior to moving the pipe.

Piping and Weld Data Collection

For newly installed high-pressure pipelines, the welder name, date of weld, weld procedure used, and GPS location should be collected for each weld. The pipe and fitting information collected should include the purchase order number, manufacturer's name, heat number, approximate segment length, coating type, and GPS location, which should be collected for each pipe segment. This information gathered shall be retained as part of the MAOP record for the pipeline and uploaded to Avista's AFM (GIS) system.

For newly installed or rebuilt high pressure gate stations and regulator stations, the welder name, date of welds, and weld procedures used should be collected for the station and displayed on the drawing or placed in the MAOP file for the station. The pipe and fitting information collected should include the pipe purchase order number, manufacturer's name, and heat number.

Toughness Testing

By engineering analysis, Avista has determined that pipelines of a certain age and size must undergo toughness testing before lowering or roping. Toughness testing is required for all diameters of high-pressure pipe fabricated prior to 1980, as well as all intermediate pressure pipe larger than 2 inches in diameter and fabricated prior to 1980. Pre-1980 manufacturing techniques and this era of pipe's tendency to exhibit lower toughness due to higher carbon levels demands this analysis before lowering. A Charpy v-notch test is commonly used to determine the toughness of a specimen by determining the amount of energy a material absorbs when fracturing.

An acceptable toughness level is determined when the average energy absorbed is 20 ft-lbs or more with no single specimen less than 15 ft-lbs on a 10 mm x 10 mm specimen at 40 degrees F. Acceptance criteria and testing shall be according to ASTM A370, Table 9. Consult Gas Engineering for an interpretation of the results.

WAC 480-93-175:

High Pressure Pipelines of any Diameter and Intermediate Pressure Pipelines Larger than 2 inches Diameter: In the State of Washington, prior to lowering any steel pipeline a study (which may consist of either a roping calculation or toughness testing, depending on the age of pipe) must be performed by Gas Engineering to determine whether the action will cause an unsafe condition. This study must be retained for the life of the pipeline.

2 inches and Smaller Diameter, Intermediate Pressure: In the State of Washington, pipelines operating at 60 psig or less which have a nominal diameter of 2 inches or less do not require a study to be performed prior to lowering if the operator can certify that no undue stresses will be placed on the pipeline and that it can be moved or lowered in a safe manner. A leak survey must be conducted within 30 days from the date these pipelines have been moved or lowered for these pipelines.

Reference the Steel Pipe Lowering Decision Flowchart at the end of this specification for guidance on sorting out the requirements for toughness testing and analysis. This chart is meant to identify minimum guidelines; Avista may choose to do additional study as necessary based on the particular circumstances of a proposed lowering site.

Recordkeeping

Studies, analyses, and toughness testing results shall be retained for the life of the facility. Copies of the analysis and test results shall be retained in Gas Engineering.

Pipe Coupon Retentions Procedures

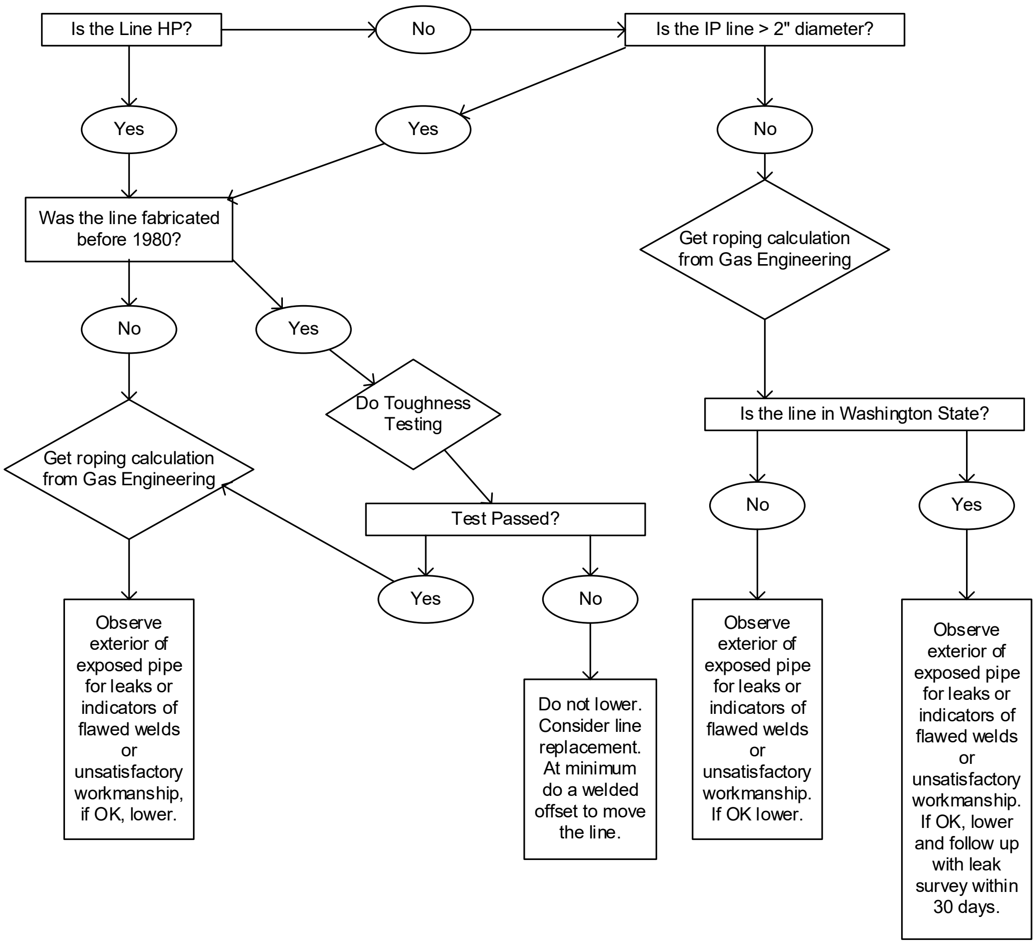
Whenever a tapping occurs on a transmission line or high pressure main, the pipe coupon should be retrieved, properly cataloged (including date, pipe size, location, Work Order number, and any pertinent notes), and kept at the local construction office for future testing as may be warranted.

Updating Maps and Records

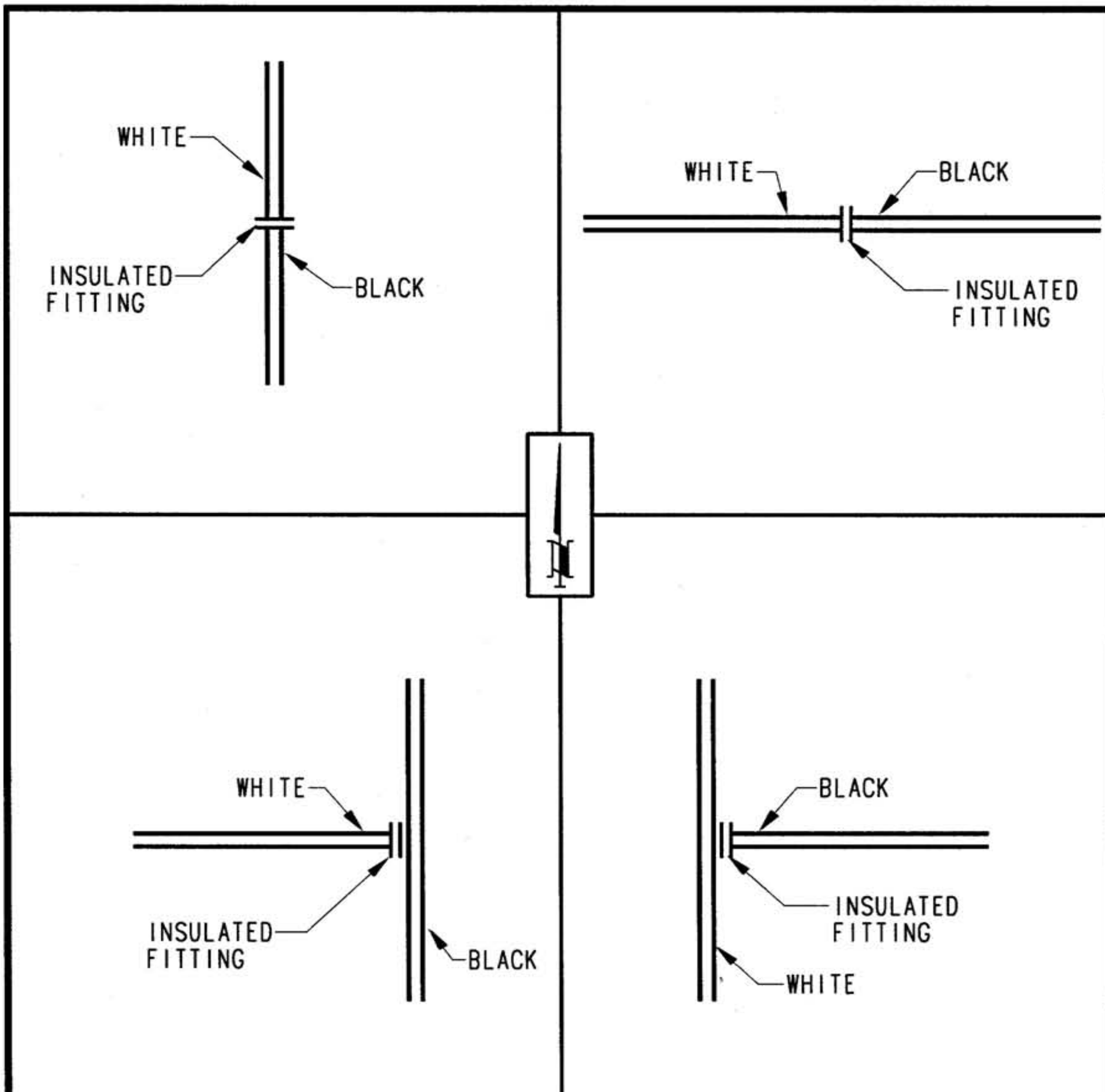
Employees responsible for construction activities shall ensure field as-built documents are completed immediately following construction, repair, or abandonment of facilities. Field as-built documents shall be subsequently mapped by the district GIS Editor within the electronic mapping system to allow for accurate gas facility locating and incorporation into maintenance schedules. The district manager in which the construction activities take place is responsible to ensure that field work as-built documents are completed and mapped in a timely manner. In Washington State, this shall be completed within 6 months following the completion of the field work. In Idaho and Oregon this is a best management practice.

WAC 480-93-018 (5): Each gas pipeline company must update its records within 6 months of when it completes any construction activity and make such records available to appropriate company operations personnel.

Steel Pipe Lowering Decision Flowchart



Note: Roping Calculations and toughness testing results shall be kept by Gas Engineering



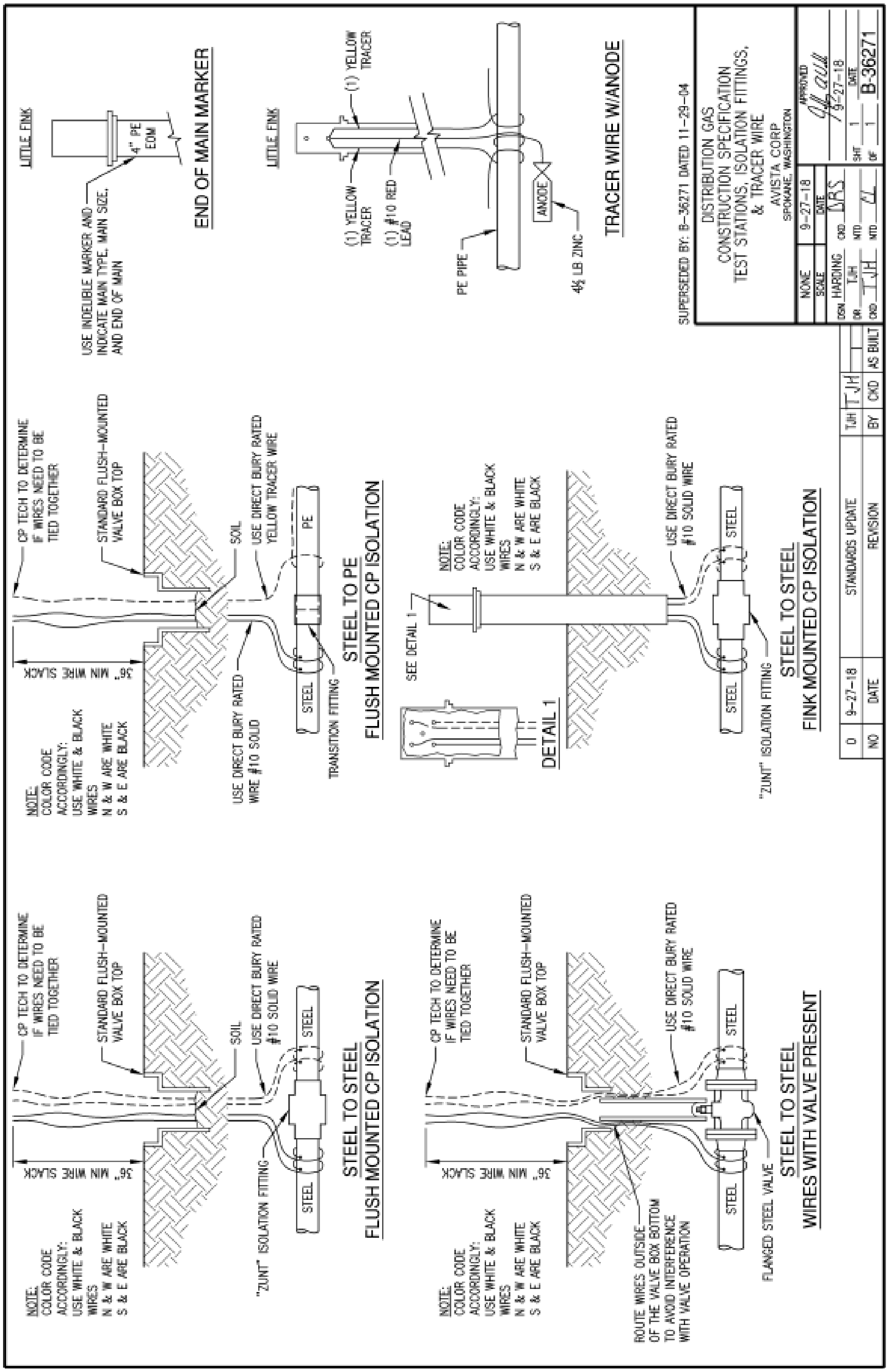
THE TEST LEADS ON THE NORTH OR WEST SIDE OF THE INSULATED FITTING SHOULD BE WHITE #10 SOLID WIRE (STOCK NO. 2831022). THE TEST LEADS ON THE SOUTH OR EAST SIDE OF THE INSULATED FITTING SHOULD BE BLACK #10 SOLID WIRE (STOCK NO. 2831020).

DISTRIBUTION GAS
STANDARD
COLOR CODING OF C.P. TEST LEADS
ACROSS INSULATED FITTINGS

AVISTA CORP
SPOKANE, WASHINGTON

SCALE	DATE	APPROVED
NONE	6-5-01	
DSN. BURGER	CKD. AB	DATE 6/8/01
DR. CJ	NTD.	SHT 1 OF 1
CKD.	NTD. JW	A-35447

NO	DATE	REVISION	BY	CKD



	PIPE INSTALLATION STEEL MAINS	REV. NO. 23 DATE 01/01/23
AVISTA Utilities	**STANDARDS** NATURAL GAS	22 OF 22 SPEC. 3.12

3.13 PIPE INSTALLATION - PLASTIC (POLYETHYLENE) MAINS

SCOPE:

To establish a uniform procedure for storing, handling, and installing plastic (polyethylene) gas pipe systems which adhere to applicable regulatory codes and provide a safe, reliable gas system.

REGULATORY REQUIREMENTS:

§192.59, §192.67, §192.307, §192.321, §192.323
WAC 480-93-178

CORRESPONDING STANDARDS:

Spec. 2.13, Pipe Design – Plastic
Spec. 2.32, Cathodic Protection Design
Spec. 3.16, Services
Spec. 3.18, Pressure Testing
Spec. 3.19, Pipe Installation – Trenchless Pipe Installation
Spec. 3.23, Joining of Pipe – Plastic (Polyethylene) – Heat Fusion
Spec. 3.24, Joining of Pipe – Plastic (Polyethylene) – Electrofusion
Spec. 3.25, Joining of Pipe – Plastic (Polyethylene) – Mechanical
Spec. 3.34, Squeeze-Off of PE Pipe and Prevention of Static Electricity
Spec. 3.44, Exposed Pipe Evaluation
Spec. 4.18, Odorization Procedures
Spec. 5.17, Reinstating Abandoned Gas Pipelines and Facilities

CONSTRUCTION REQUIREMENTS:

General

Personnel installing and inspecting polyethylene (PE) pipelines shall be instructed, trained, and qualified with the equipment and procedures required to install polyethylene pipelines.

Qualified Joiners

No person shall perform plastic pipe joining on polyethylene pipe and associated components until that person has been qualified in the approved methods of plastic pipe joining. Upon completion of qualification, a certification record will be issued and must be available for inspection when performing plastic pipe joining in the field. Refer to Specifications 3.23, 3.24, and 3.25 for Joining of Pipe - Plastic. No solvent joints shall be used. No person shall perform inspection of plastic joints without being qualified by training or experience in evaluating the acceptability of plastic pipe joints made under the applicable joining procedures.

Installations of polyethylene pipelines and facilities shall be inspected on a sampling basis to ensure that the work conforms to Avista standards, as well as to the applicable state, federal, and local requirements. The Inspector shall have the authority to order the repair or the removal and replacement of any component that fails to meet the above requirements.

Installation of plastic pipe that requires squeeze-off shall be performed in accordance with the procedures outlined in Specification 3.34, Squeeze-Off of PE Pipe and Prevention of Static Electricity.

Monitoring of Pressures

Gas personnel performing work on pipelines and facilities that could result in loss of pressure or overpressure to the system shall install accurate pressure gauges upstream and downstream of the work site. The pressure gauges shall be continuously monitored as long as necessary so that personnel can respond accordingly if system pressures are greatly affected. It may also be necessary to install a temporary bypass if a system is not looped or if the pipeline work could result in loss of pressure to the system. Refer to Specification 3.12, Pipe Installation – Steel Mains for temporary bypass details and requirements.

Additionally, there may be times when merely monitoring downstream pressure may not be sufficient to prevent customer outages without further action. It may be necessary during warm days or periods of low gas use to intentionally draw down the pressure of the downstream system and observe it to confirm the existence of a looped system prior to altering the system or leaving the area. Consult Gas Engineering for recommendations prior to altering any system's pressure. Any loss of pressure that may have extinguished pilots or that may have affected the normal operation of the customer's gas equipment shall be treated as an outage and the procedures followed as outlined in the GESH, Section 5, Emergency Shutdown and Restoration of Service.

Storage of Pipe and Associated Components

Per manufacturer's latest recommended practices and industry best practices, the following are guidelines for the storage of PE pipe and associated components:

Polyethylene pipe and components shall be stored so as to prevent the possibility of the material being damaged by crushing, gouging, or piercing. The height to which polyethylene pipe may be stacked depends on factors such as size, wall thickness, and ambient temperature. At no time should the height of the stack cause the pipe to be forced out of round. Care must be taken at all times to protect the polyethylene pipe and components from fire, excessive heat, harmful chemicals, and mechanical damage.

Yellow plastic pipe, including anodeless risers, transition fittings, and stick EFV assemblies made with yellow PE pipe, shall not be used if more than 3 years (36 months) old. Black plastic pipe, including anodeless risers, transition fittings, and stick EFV assemblies made with black PE pipe, shall not be used if more than 10 years (120 months) old. Pipe, risers, transition fittings, and stick EFVs, older than this must be discarded. The age of anodeless risers and transition fittings is based upon the date the plastic pipe was manufactured and not the date the riser or transition fitting was fabricated. The age of the stick EFV assembly is based upon the date the fitting was fabricated.

PE components such as elbows, tees, couplings, valves, etc. should be stored indoors and protected from UV exposure as a matter of company policy. PE components should be discarded if they are found to be older than the following:

- Yellow plastic components – 3 years (36 months)
- Black plastic components – 10 years (120 months)

Use sandbags or planking to protect sticks of pipe from ground surface conditions that might damage the pipe. The ends of pipe should be sealed with end caps or other acceptable means to keep debris, water, and rodents out of the pipe. Banded bundles should be offset with wood dunnage when stacked. Stacks should be leveled to prevent leaning and uneven loading on the bottom bundle. Pipe coils should be stored (center hole vertical) on pallets or dunnage on a level surface.

Handling

The following guidelines must be followed for PE pipe handling:

Polyethylene pipe shall be handled carefully to eliminate the possibility of damage during loading and unloading operations. Whether using a forklift or forks attached to the bucket of a front-end loader or backhoe, the forks should be checked for jagged edges or burrs. If the forks are marred, cover them with a suitable protective covering to prevent gouging of the pipe. The forks should be spread as wide as possible.

The pipe must be supported during transport to minimize movement. Ropes and other securing devices shall be padded to prevent damage to the pipe. Chains shall not be used to secure the pipe. Equipment or other supplies shall not be placed on top of the pipe.

Banded bundles should be picked up one bundle at a time. Banding should not be removed until the bundles have been transported to the storage area and secured in a stable and safe manner.

The stringing of coils of plastic pipe may be accomplished by hand or from a reel. Coils should not be rolled over sharp objects or pulled over rough surfaces. Stringing of straight lengths should be done by lifting the pipe from the truck to the ground. The pipe should be protected from rocks or other abrasive material during this operation and should not be dropped.

Coiled polyethylene pipe is confined with straps at intervals within the coils. As the pipe is uncoiled, only the outside straps should be cut.

Polyethylene pipe shall be carefully inspected for kinks, cuts, gouges, deep scratches, punctures, and other imperfections after each of the handling operations. Defective or damaged pipe must be rejected.

Installation

Plastic pipe is typically installed below ground level with the exception of temporary emergency repairs and encased bridge crossings. Gas Engineering must approve the use of plastic pipe above ground.

Pipe must be firmly supported along its entire length to minimize any stresses induced by settlement.

Care should be taken to assure pipe ends are kept free of debris and water at all times. As a minimum, plastic end caps shall be used in ends of main during off-construction periods.

If water or debris is suspected to have entered pipe, the entire length of suspected line shall be pigged until all water and/or debris is eliminated.

Temporary Bypass

See Specification 3.12, Pipe Installation – Steel Mains for temporary bypass details and requirements.

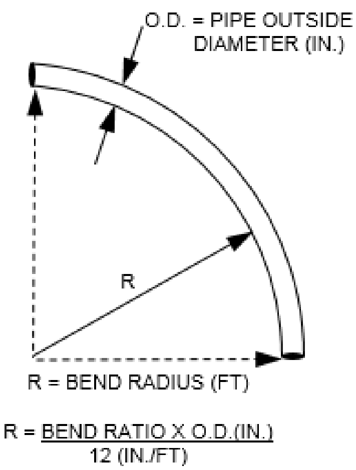
Field Bending

A field bend is an intentional deflection of pipe without the use of a fitting. Plastic pipe should be installed so that there are no bends with a radius less than 25 times the outside pipe diameter (20 times the outside diameter for SDR 7). When a fusion or fitting is present in the bend the minimum bending radius is 100 times the outside pipe diameter of the pipe for a recommended distance of 5 times the outside diameter on each side of the fusion or fitting. Refer to the table below:

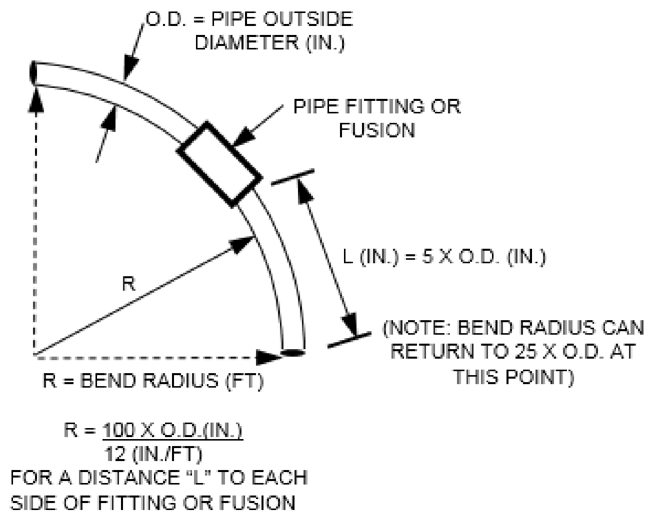
Minimum Permanent Bending Radius

Pipe Size (in.)	SDR	Min. Bend Ratio	Outside Diameter "O.D" (in.)	Min. Bend Radius "R" (ft. - in.)	Min. Bend Ratio with a Fusion or Fitting Present	Min. Bend Radius with a Fusion or Fitting Present "R" (ft. - in.)	Min. Distance for 100x Radius Each Side of Fusion or Fitting "L" (ft. - in.)
1/2" CTS	7	20	0.625"	1' - 1"	100	5' - 3"	0' - 4"
3/4" IPS	11	25	1.050"	2' - 3"	100	8' - 9"	0' - 6"
1-1/4" IPS	11	25	1.660"	3' - 6"	100	13' - 10"	0' - 9"
2" IPS	11	25	2.375"	5' - 0"	100	19' - 10"	1' - 0"
3" IPS	11	25	3.500"	7' - 4"	100	29' - 2"	1' - 6"
4" IPS	11.5	25	4.500"	9' - 5"	100	37' - 6"	1' - 11"
6" IPS	11.5	25	6.625"	13' - 10"	100	55' - 3"	2' - 10"

*Calculation from Plastics Pipe Institute Handbook of Polyethylene Pipe 2nd Edition, Chapter 7 Table 4.



FIELD BEND – PE PIPE (PIPE ONLY)



FIELD BEND – PE PIPE (FUSION OR FITTING IN BEND)

The exception to the bending radii in the above table is when PE pipe is being installed or utilized in prefabricated risers and new construction risers. It is acceptable for the bend radius to exceed the above values and be more similar to the approved chute bending radii shown on Sheet 6 of this Spec 3.13.

Tensile Loading

The pipe must be installed so it will be free of tensile loading. When plastic pipe is installed on a warm day, allowance must be made for thermal contraction; otherwise, the pipe will be in tension when it cools. Refer to Specification 2.13, Pipe Design - Plastic.

For direct burial, where clearance from other facilities is not a problem, "snake" the pipe in the ditch to provide excess length.

On insert work, additional pipe should be provided at ends of pipe being inserted.

For trenchless installation, refer to the use of "Safe Pulling Forces" later in this specification and Specification 3.19, Trenchless Pipe Installation.

At tie-in locations, the pipe should be cut long so that the tie-in fittings are in compression when installed. Whenever possible, make tie-ins during the cooler part of the day, after the pipe has cooled to ground temperature. This is particularly important for insert construction and where clearance problems prohibit the pipe from being "snaked".

Tracer Wire

Plastic pipe that is not encased in steel must have an electrically conducting tracer wire buried with the pipe for locating the pipe while underground. Insulated #12 solid type coated tracer wire shall be installed so that the wire is taped (with black electrical tape) to the upper half of the pipe at no more than 20 foot-intervals. When installing pipe around a bend, tracer wire may need to be taped at closer intervals to ensure that wire is in line with pipe after being backfilled for more accurate locates. <u>Do not wrap the wire around the buried pipe or the PE service tee tower.</u> Refer to Drawings A-35776 at the end of this specification.

For plastic pipe that is encased in steel, maintain continuity of the tracer wire by insertion of tracer wire along with the plastic through the steel casing. It is recommended that multiple strands of tracer wire be used to ensure at least one remains unbroken. Cadwelding of the tracer wire to each end of the steel casing is one means of maintaining continuity but is not preferred as it lowers the level of cathodic protection on the tracer wire.

A #10 yellow solid or stranded wire should be used when boring plastic pipe or when installing pipe via split and pull. The heavier gauge wire will allow for added strength during the pullback process. It is recommended that multiple strands of tracer wire be used to ensure at least one remains unbroken. When boring, it is not necessary to tape the wire to the pipe as you would in an open trench installation, since the tape is likely to come off during pullback. Once the installation is completed, the tracer wire(s) should be checked for continuity to confirm at least one was not damaged.

Tracer wire connections should not be made to steel main or steel fittings when transitioning to plastic pipe. Two #10 wires shall be "Cadwelded" on the steel side and a tracer wire on the plastic side brought up into the test box. Do <u>not</u> tie wires together. Refer to Specification 3.12, Drawing B-36271 for details. The exception to this is when inserting plastic service into an old steel service line. Refer to Specification 3.16, Services, Insertion of Old Steel Services along Steel Main, or gain approval of other proposed deviations from standard policy from a Cathodic Protection Technician.

A 4-1/2 lb. zinc anode should be installed on the tracer wire at intervals not to exceed 1000 feet to prevent corrosion of the tracer wires. At a minimum a 4-1/2 lb. anode shall be installed on the tracer wire at the end of each new plastic main to help with current flow for locating.

In order to monitor continuity of tracer wire and for locating, cathodic test stations should be installed as needed i.e., approximately every 1000 feet where there is no place to connect to the system for locating, such as a service. Refer to Specification 3.12, Drawing B-36271.

At the riser, the tracer wire should be terminated (clipped) so that it does not make contact above the insulated valve or with the meter, which can cause a cathodic short across the insulated fittings. Ensure a sufficient amount of wire is left aboveground to allow connection to and testing with a multi-meter. The tracer shall be secured to the meter riser with a half-hitch knot **(do not tape wire to riser; this can trap moisture and cause corrosion).**

Wire Connections

Tracer wires will be joined by a direct-bury splice kit (in line or “Y” connection). Maintain electric continuity at wire connections.

Joining and splice connections shall be either encapsulated in a dielectric type gel connector which is the preferred method, or a crimped sleeve covered by an approved dielectric sealing compound (such as Aqua-Seal) and tape wrapped. For encapsulated connectors involving two or more cut wires, the wires should be tied together loosely with an over-the-hand type knot approximately 6 inches to 12 inches from the end of the wires prior to installing wires into the connector. This knot alleviates strain on the wire connection. For encapsulated connectors involving one cut and one uncut wire, a strain relieving knot or other wire strain relieving method is not necessary. Refer to Drawing A-36277 at the end of this specification for encapsulated connector details.

Pulling Limitations

Polyethylene pipe may be pushed through a casing or “planted” with a plow-type chute arrangement. It is not to be pulled through a casing pipe with mechanical equipment or pulled through the ground with a plow unless special precautions are taken to eliminate the possibility of overstressing. Using a pulling head incorporating a break-away device or "weak link" are two methods of eliminating the possibility of overstressing and are discussed later in this specification. Additionally, it is recommended that pulling forces be monitored via pressure gauge when equipment permits

Plowing and Planting

Plowing and planting involves cutting a narrow trench and feeding the pipe into the trench through a shoe or chute fitted just behind the trench cutting equipment. The shoe or chute should feed the pipe into the bottom of the cut.
The minimum short term bending radius for plastic pipe during plowing installations is as indicated in the following table:

Minimum Temporary Bending Radius

Pipe Size	SDR	Outside Diameter (in.)	Minimum Chute Bending Radius* (in.)
1/2" CTS	7	0.625	6
3/4" IPS	11	1.05	10
2" IPS	11	2.375	20
4" IPS	11.5	4.5	41
6" IPS	11.5	6.625	59

*Calculation from Plastics Pipe Institute Handbook of Polyethylene Pipe 2nd Edition, Chapter 10 Table 3

Small diameter coiled pipe is usually fed over the trenching equipment and through the shoe. Straight lengths may be butt fused into a long string, then fed over and through the shoe. Plowing shoes or chutes should be inspected periodically to assure that they are not worn and that the pipe does not kink or bind on the shoe during installation.

Plowing operations should be completed in materials acceptable for padding (sometimes referred to as bedding) pipe. Prior to plowing, a subsurface review of the soil conditions shall be conducted to determine the acceptability of the soil to plowing and future padding of the installed pipe. Soil should be primarily sand or cohesive earth with a minimum of rock.

Caution Tape

When plowing in PE pipelines that are 2 inches and larger, yellow gas caution tape with the words to the effect "CAUTION, GAS LINE BURIED BELOW" should be installed approximately 12 inches above the pipeline. This tape shall be installed with the pipe by feeding the tape through one of the chutes on the plow.

The use of caution tape should also strongly be considered in open-trench pipeline installations. These types of locations may include but are not limited to installations within private easements and dry-line installations where the presence of a gas pipeline may be unexpected to excavators.

Dry Line Installations

As a general rule, dry line gas lines should not be installed unless there is a high degree of certainty that the line will be "gassed up" within three years. Additionally, consideration should be given to abandoning dry lines that have been in place for five years or greater to lessen the burden of ongoing locating of the facility. If the need arises to bring into service a former dry line that has been abandoned, it can be done in accordance with Specification 5.17, Reinstating Abandoned Gas Pipelines and Facilities. Refer to Specification 3.18, Dry Line Pipe for additional details on pressure testing of dry line pipe.

Pulling-In

Pulling-in involves cutting a trench, then pulling the pipe in from one end of the trench. Pulling-in may be accomplished as a simultaneous operation by attaching the leading end of the pipe behind the trench cutter or as a separate operation after the trench has been opened. In either case, pulling-in requires a relatively straight trench and the pulling force applied to the pipe must not exceed what might damage the pipe. Refer to "Safe Pulling Forces" below for additional information. This method should be limited to shorter runs. Care shall be taken when pulling in pipe to protect the exterior pipe surface. Sandbags and sand padding (sometimes referred to as bedding) to be placed in the trench to support and protect the exterior of the pipe during pull-in.

Safe Pulling Forces

When polyethylene pipe is subjected to a significant short-term pulling stress, the pipe will stretch somewhat before yielding. This is a possibility during pull-in installation and horizontal directional drilling as well as split and pull procedures described further in Specification 3.19, Trenchless Pipe Installation. The safe pulling force as shown in the following table assures that the pulling stress in the pipe is limited to about 40 percent of its yield strength, the level at which the pipe will recover undamaged to its original length in a day or less after the stress is removed.
The safe pull force for polyethylene pipe is determined by the following equation:

$$Safe\ Pull\ Force\ (lbs) = F_Y F_T T_Y \pi (OD^2)\left(\frac{1}{SDR} - \frac{1}{SDR^2}\right)$$

Where:

F_Y = Tensile yield design factor
F_T = Time under tension design factor
T_Y = PE material yield strength
OD = Outside diameter, inches
SDR = Standard dimension ratio

Factor	Recommended Values			
F_Y	0.40*			
F_T	1.00 for up to 1 hour pull	0.95 for up to 12 hour pull	0.91 for up to 24 hour pull	
T_Y (PE 2406/2708)	2,600 psi at 73°F	2,300 psi at 100°F	1,900 psi at 120°F	1,500 psi at 140°F

*To prevent plastic deformation and allow for full strain recovery, tensile stress in PE should not exceed 40% of yield strength

The safe pull forces for PE 2406/2708 medium density PE pipe for varying pipe temperatures, diameters and SDRs used by Avista are shown in the following tables:

Safe pulling forces at a pipe temperature up to 73°F (PE 2406/2708)

Pipe Size (In)	Outside Diameter (In)	Standard Dimension Ratio (SDR)	Safe Pull Force (lbs) up to 1 hour pull	Safe Pull Force (lbs) for up to 12 hour pull	Safe Pull Force (lbs) for up to 24 hour pull
½ CTS	0.625	7	156	148	142
¾ IPS	1.050	11	298	283	271
2 IPS	2.375	11	1,523	1,447	1,386
4 IPS	4.500	11.5	5,253	4,990	4,780
6 IPS	6.625	11.5	11,385	10,816	10,361

Safe pulling forces at a pipe temperature between 74°F and 100°F (PE 2406/2708)

Pipe Size (In)	Outside Diameter (In)	Standard Dimension Ratio (SDR)	Safe Pull Force (lbs) up to 1 hour pull	Safe Pull Force (lbs) for up to 12 hour pull	Safe Pull Force (lbs) for up to 24 hour pull
½ CTS	0.625	7	138	131	126
¾ IPS	1.050	11	263	250	240
2 IPS	2.375	11	1,347	1,280	1,226
4 IPS	4.500	11.5	4,647	4,414	4,229
6 IPS	6.625	11.5	10,072	9,568	9,165

Safe pulling forces at a pipe temperature between 101°F and 120°F (PE 2406/2708)

Pipe Size (In)	Outside Diameter (In)	Standard Dimension Ratio (SDR)	Safe Pull Force (lbs) up to 1 hour pull	Safe Pull Force (lbs) for up to 12 hour pull	Safe Pull Force (lbs) for up to 24 hour pull
½ CTS	0.625	7	114	108	104
¾ IPS	1.050	11	218	207	198
2 IPS	2.375	11	1,113	1,057	1,013
4 IPS	4.500	11.5	3,839	3,647	3,493
6 IPS	6.625	11.5	8,320	7,904	7,571

Safe pulling forces at a pipe temperature between 121°F and 140°F (PE 2406/2708)
(Do not pull back if the pipe temperature is above 140°F)

Pipe Size (In)	Outside Diameter (In)	Standard Dimension Ratio (SDR)	Safe Pull Force (lbs) up to 1 hour pull	Safe Pull Force (lbs) for up to 12 hour pull	Safe Pull Force (lbs) for up to 24 hour pull
½ CTS	0.625	7	90	86	82
¾ IPS	1.050	11	172	163	157
2 IPS	2.375	11	879	835	800
4 IPS	4.500	11.5	3,031	2,879	2,758
6 IPS	6.625	11.5	6,569	6,240	5,977

If these safe pulling forces are exceeded, the pipe should be abandoned, and the pull-in operation repeated, or the pipe should be installed by other means. Just because pipe does not break when pulling forces are exceeded does not mean that it may not be irreparably damaged. When the pull force exceeds the above limits, the pipe may begin to yield (stretch) to a point where it will not recover to its original length. As polyethylene pipe will stretch as much as 800 percent to 1000 percent before it breaks, it may be visually impossible to tell if the pipe integrity has been damaged if the safe pull force is exceeded.

To help assure safe pulling forces are not exceeded during installation of plastic pipe by mechanical means (bore machine, backhoe, winch, etc.) a break-away device or a “weak link” shall be utilized during any trenchless installation methods.

During pull-back, it is recommended that the exit pit farthest away from the pull-back machine be monitored to ensure the pipe being pulled maintains a constant rate of pull-back until installation is complete. Pipe that shows a slowed rate of installation or stops moving at the exit pit may be an indication of the pipe being stuck in the bore hole during pull-back. Plastic (polyethylene) pipe may stretch slightly during the pulling operation and care should be taken to allow the pipe to recover to its original length before it is tied in (this may take as long as 24 hours). To assure the pipe has recovered to its original length after pullback, it is recommended that the pipe be allowed to rest in place for a period of time equal to or greater than twice the time of pull-back or one hour, whichever is greater, up to a maximum rest time of 24 hours before making tie-ins at either end. One way to verify pipe recovery is to compare the measured length of the pull-back with the length of the pipe installed as determined by calculating the differences in footage markings stenciled on the pipe.

Tie-ins may be completed without a wait period if all of the following conditions are met:

1. The HDD or split-and-pull length does not exceed 500 feet.
2. A “weak link” of reduced pipe diameter is used, not a break away pin (shear pin).
3. The “weak link” must not show any elongation during pullback. This shall be verified by measuring the length of the weak link before and immediately after the HDD or split-and-pull operation is completed. These measurements shall be recorded and documented in the job paperwork. If the “weak link” shows any elongation, the pipe shall rest per the times described in the paragraph above prior to performing any tie-ins.

Break –Away Pin or Weak Link

Pipe should be pulled-in behind a pulling head, typically shaped like a bullet that is one or two pipe diameters larger than the pipe being pulled-in. Refer to “Pullback” in Specification 3.19, Trenchless Pipe Installation for additional information. In order to assure the safe pull force is not exceeded during mechanical pullback, a calibrated break-away pin or “weak link” shall be used between the pulling head and the gas pipe as described below.

A “weak link” can be used between the pulling head and the gas pipe in lieu of a calibrated break-away pin. A “weak link” shall consist of a one foot long (minimum) section of pipe measuring at least one available stock pipe diameter smaller than the pipe to be pulled and composed of the same material (for the purposes of a weak link, unimodal PE is considered the same material as bi-modal). However, using the “weak link” will not always assure that the amount of pulling force being applied is not exceeding the safe pull force of the gas pipe (again, defined as 40 percent of the gas pipe's yield strength, the level at which the pipe will recover undamaged to its original length in a day or less after the stress is removed). In some cases, the pulling force exerted on the gas pipe with the “weak link” method using one pipe size smaller may reach 60 percent of the yield strength before the "weak link” fails. In this case, the pipe will still only stretch to a point where it will return to its original length, but this may take longer than 24 hours.

If a break away pin or “weak link” fails during a pullback installation, and it can be shown that the carrier pipe was not subjected to unsafe pulling forces or pulling stresses greater than 40 percent of the pipe’s yield strength then it is acceptable to utilize the installed pipe without abandonment. Contact Gas Engineering for review prior to proceeding.

Static Charges

Static electric charges may build up on both the inside and outside surfaces of polyethylene pipe. Localized static electricity build-up occurs because polyethylene pipe does not readily conduct electricity. Charges are generated by physical handling or by the high velocity flow of gas through polyethylene mains and services (i.e., purging, flow of gas through restriction). Discharge of static electricity can cause unpleasant shocks or ignite a gas-air mixture. Refer to Specification 3.34, Squeeze-Off of PE Pipe and Prevention of Static Electricity for specific requirements.

Examining Buried Pipe

When previously buried plastic pipe is exposed, an Exposed Piping Inspection Report (Form N-2534) shall be completed in accordance with Specification 3.44, Exposed Pipe Evaluation.

Pigging of Pipe

Refer to Specification 3.12, Pigging of Pipe, for more information.

Odorizing Newly Installed Pipe

Newly installed pipe may present challenges with regards to meeting the required odorant detection levels as defined in Specification 4.18, Odorization Procedures. New pipe, especially which is gassed up, but not immediately put into service, tends to absorb odorant in the pipe walls. Consideration should be made to “pickle” such pipe per the sub-section titled “Pickling Newly Installed Piping” in Specification 4.18, Odorization Procedures.

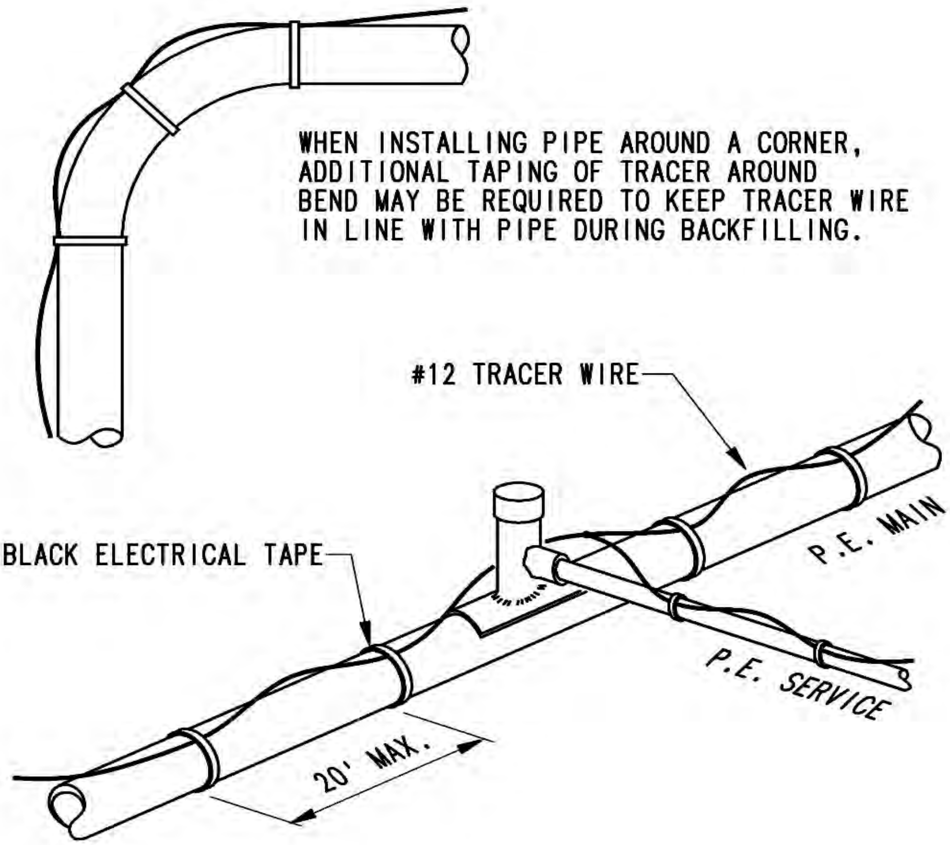
Pressure Testing

New or replaced main and new, replaced, or reconnected services transporting natural gas must be pressure tested. Refer to Specification 3.18, Pressure Testing for specific requirements.

Updating Maps and Records

Employees responsible for construction activities shall ensure field as-built documents are completed immediately following construction, repair, or abandonment of facilities. Field as-built documents shall be subsequently mapped by the district GIS Editor within the electronic mapping system to allow for accurate gas facility locating and incorporation into maintenance schedules. The district manager in which the construction activities take place is responsible to ensure that field work as-built documents are completed and mapped in a timely manner. In Washington, this shall be completed within 6 months following the completion of the field work. In Idaho and Oregon this is a best management practice.

WAC 480-93-018 (5): Each gas pipeline company must update its records within 6 months of when it completes any construction activity and make such records available to appropriate company operations personnel.



NOTE: MAXIMUM DISTANCE IS 20 FEET; HOWEVER, TRACER WIRE MAY NEED TO BE TAPED AT CLOSER INTERVALS TO ENSURE THAT WIRE IS IN LINE WITH THE PIPE AFTER BACKFILLING.

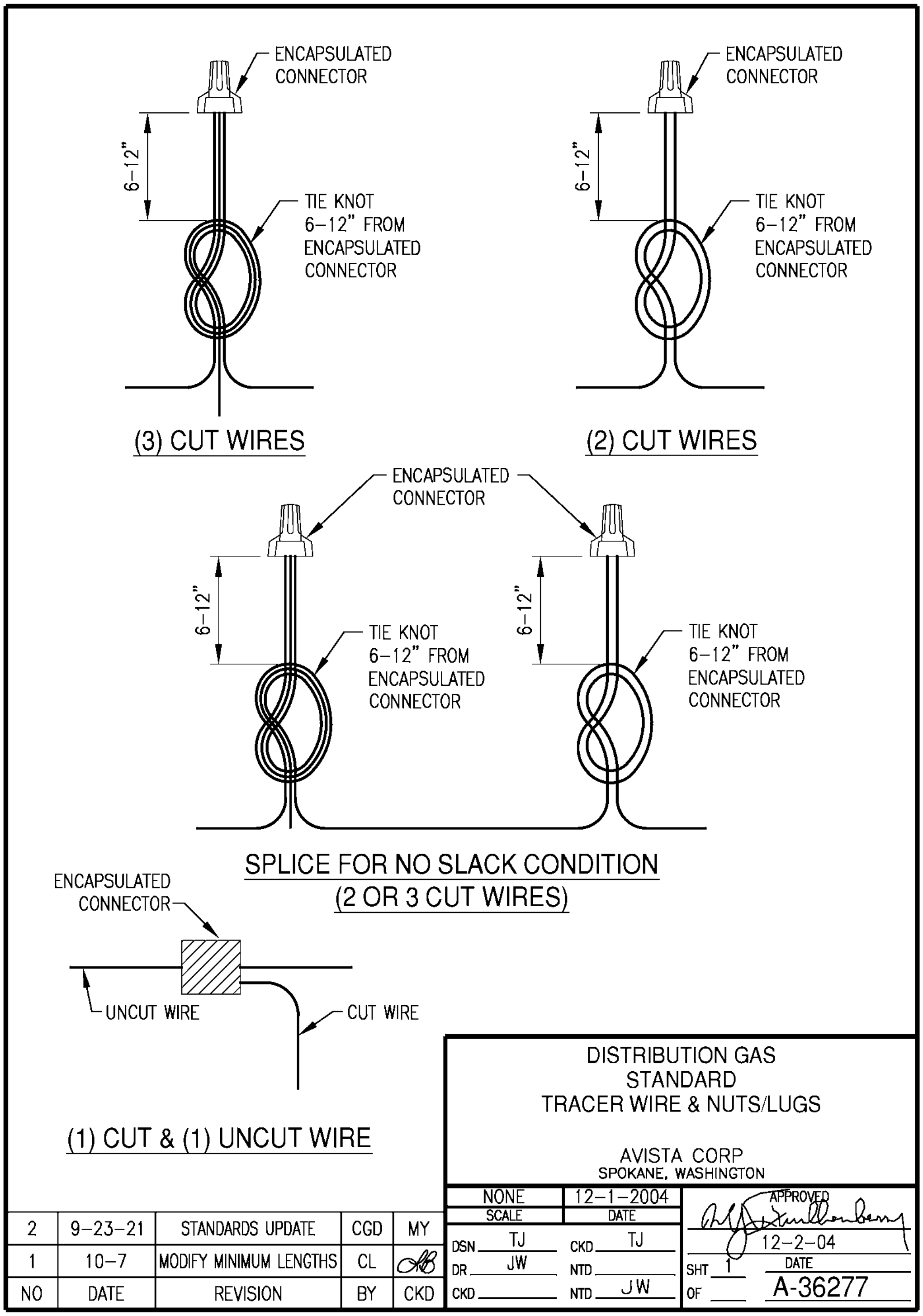
DISTRIBUTION GAS
STANDARD
TAPING TRACER WIRE TO PIPE DETAIL

AVISTA CORP
SPOKANE, WASHINGTON

NONE SCALE	6-22-01 DATE	APPROVED
DSN. BURGER DR. CJ CKD.	CKD. AB NTD. NTD. JW	7-2-01 DATE SHT 1 OF 1 A-35776

NO	DATE	REVISION	BY	CKD
1	11-08	CORRECTED TO DATE	DLO	KB

A-35776.0.01.01.N.GAS.STD.1



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3.14 PRE-CHECK LAYOUT AND INSPECTION

SCOPE:

To provide qualitative guidelines for layout and inspection of a job site prior to construction.

REGULATORY REQUIREMENTS:

§192.325(c)

CORRESPONDING STANDARDS

Spec. 3.12, Pipe Installation – Steel Mains
Spec. 3.15, Trenching and Backfilling
Spec. 4.13, Damage Prevention Program

PRELIMINARY INSPECTION AND LAYOUT:

General

The job location for gas pipeline installations, extensions, or replacements shall be inspected prior to any work. During this inspection, the proposed Avista installation should be pre-marked in white paint so that other affected parties can determine Avista's worksite.

Pre-Construction Notification for Locate Tickets

After inspecting the job site, mark the proposed installation location(s) with white marking paint or other appropriate white marking materials prior to requesting a locate ticket through the local One Call System. The One Call System shall be notified with the appropriate description of the dig area so that the locators for underground facilities identified on the ticket can locate and mark the appropriate area prior to construction. The requestor must include in the description, a contact name and phone number in case there are questions by facility locators with regard to the locate ticket request.

Note: When filling out the locate ticket request, be sure to select (as applicable) the "Type of Work" that most accurately reflects the work that will be done.

Notifications for locates shall be made at least 2 business days prior to planned construction (Saturdays, Sundays and federal / state holidays are not "business days"). EXCEPTION: An exception to this notification timeframe is when Avista is responding to a gas emergency. In this case, a notification for locates must be made as soon as possible and Avista shall take reasonable care to protect underground facilities.

An EMERGENCY means any condition involving a clear and present danger to life, property, or a customer service outage. In Oregon the definition includes interruption of essential public services and in Idaho the definition includes blockage of roads/transportation facilities that require immediate action.

Design Locates (Oregon) – Facility locators have 10 days to respond to the request by locating and marking facilities, providing best available information, or by contacting the person requesting the design information to provide facility information. The excavator shall either maintain the markings, or if required by state dig laws, request for new locates to be made. Consult the respective state underground dig laws for specifics and refer to Specification 4.13, Damage Prevention Program.

Pre-Construction Inspection

Job planning should consider expected traffic conditions and necessary barricade requirements in accordance with good safety practices, local safety ordinances, and Avista's Incident Prevention Manual (Safety Handbook). Job planning should also consider possible conflict with other construction work in immediate area.

Verify that underground structures which might be encountered during excavation are clearly marked by the utility, city, municipality, or agency to which they belong.

When pipe is delivered and unloaded on the job site prior to the start of the work, it shall be placed in such a way as to offer a minimum hazard to vehicular or pedestrian traffic.

Pipeline materials shall be inspected for any damage prior to the start of installation. Damaged pipe or fittings shall not be installed. If the coating on steel pipe is damaged, but the pipe itself is not, the coating shall be repaired per Specification 3.12, Pipe Installation – Steel Mains.

Layout

When running a main extension in a residential area or commercial area, consideration should be given to notifying property owners of impending construction. This may include written or verbal communications and should include project purpose, duration, and method of inquiry about potential gas service hookup.

Mains should run parallel to street, alley, or highway centerlines. Gas mains should be located on opposite side of the street from water mains where possible.

Gas mains shall not run through manholes or footings but shall be offset around them unless a utility sleeve has been specifically approved by the impacted utility and Gas Engineering.

Joint Ditch

When installing mains and services in a joint trench with electric, telephone, fiber optic, cable TV, or any other unspecified utility, consult the Avista Electric Service and Meter Requirements for ditch and service stub requirements, or other local utility guidelines, as well as clearances as outlined in Specification 3.15, Trenching and Backfilling.

3.15 TRENCHING AND BACKFILLING

SCOPE:

To establish uniform procedures for trenching, backfilling, and marking natural gas piping systems.

REGULATORY REQUIREMENTS:

§192.319, §192.325, §192.327, §192.361, §192.707

OAR 952-001-0070
WAC 480-93-124, 480-93-170

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design - Steel
Spec. 2.13, Pipe Design – Plastic
Spec. 3.13, Pipe Installation, Plastic (Polyethylene) Mains
Spec. 3.44, Exposed Pipe Evaluation
Spec. 5.15, Pipeline Patrolling - Pipeline Markers

TRENCHING REQUIREMENTS:

General

Those persons operating excavating, boring, or trenching equipment (backhoes, track excavators, trenchers, drilling machines, etc.) should be experienced and knowledgeable on each piece of equipment being used.

Cover

High pressure transmission lines shall be installed with a minimum of 36 inches of cover in normal soil (42 inches is preferred) and have at least 24 inches of cover in consolidated rock.

High pressure distribution mains should be installed with a minimum of 36 inches of cover (42 inches is preferred), but in all cases shall be installed with a minimum of 24 inches of cover.

Intermediate pressure mains should be installed with a minimum of 30 inches of cover, but in all cases shall be installed with a minimum of 24 inches of cover.

Services should be installed with a minimum of 24 inches of cover but in all cases shall be installed with a minimum of 18 inches cover in streets and roads, and 12 inches of cover on private property. Service risers may be installed at a depth between 18 and 24 inches to prevent covering the 'Do not bury' line on the riser. In these circumstances, the service piping should transition to a minimum cover depth of 24 inches as soon as practical. Consideration should be given to install that portion of a service residing within the road right-of-way at depths equivalent to a standard main depth. Additional cover may be required on road crossings by the local jurisdiction.

Where an underground structure prevents the installations of a pipeline with the minimum cover, the pipeline may be installed with less cover if it is provided with additional protection to withstand anticipated external loads. Any additional protection should not prevent ability to maintain pipeline.

Additional cover should be provided as needed to assure protection of pipeline from other structures and future erosion or removal of cover.

Pipe which is installed by open trenching in a river or stream must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock. For boring depth requirements refer to Specification 3.19, Trenchless Pipe Installation Methods.

Clearances – Steel and PE Pipelines

Each gas pipeline should be installed with a minimum 12-inch radial (non-longitudinal) separation from any foreign utility crossing, for pipelines operating at 20 percent SMYS or greater this clearance is a must. If this clearance cannot be maintained, the pipeline must be installed with enough clearance to allow for proper maintenance of the facilities and be protected from damage that might result from proximity to other utilities. Consideration should be made to protect against physical and cathodic damage that might occur from close proximity to other structures or utilities. For PE pipelines, a casing or conduit may be used.

Each gas pipeline, <u>including services</u>, should be installed with a 5-foot minimum longitudinal separation from sanitary sewer and storm water pipelines or at a further distance as specified by the appropriate regulating agency. If the sewer is pressurized, a 3-foot separation is sufficient.

No gas pipelines, <u>including services</u>, shall be installed through, above, or below a septic drain field without approval of Gas Engineering. A minimum separation of 10 feet (25 feet preferred) from sewer drain lines and leech fields should be maintained. Septic and sewer systems afford an easy path for gas migration should a leak ever occur.

Each pipeline <u>including services</u> should be installed with a 3-foot minimum longitudinal separation from other non-gas underground utilities or at a further distance as specified by the appropriate regulating agency. If this clearance cannot be maintained, the pipeline must be protected from damage that might result from proximity to the other structure. Consideration should be made to protect against physical and cathodic damage that might occur from close proximity to other structures or utilities.

When necessary, plastic pipe may be installed in a joint trench with other utilities. A longitudinal separation not less than 12-inches should be maintained. If this clearance cannot be maintained, pipe must be installed with enough clearance to allow for proper maintenance of the facility and be protected from damage that might result from proximity to the other utilities sharing the trench.

Customer's gas piping should not be installed within 12 inches of Avista's gas pipeline.
Each gas pipeline must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.

Plastic pipe shall not be installed closer than 10 feet of a steam or hot water pipeline and in general should not be installed in an area where steam or hot water distribution systems are located.

Each gas pipeline should be installed with a minimum of 12 inches of clearance from a culvert while maintaining the minimum cover requirements.

Pipelines installed adjacent to buildings should be done so with a concern for future maintenance and an awareness of the possibility of gas becoming trapped under the building should a leak occur. Mains and services (excluding the meter riser itself) should be located a minimum of 5 feet from the foundation of a building. Deviations from the separation requirement for mains must be approved by Gas Engineering, whereas deviations for services will follow the guidance for “Should” as found in the Foreword.

See also “Location Considerations” in Specification 3.16, Services.

Vegetation Clearance

Gas distribution intermediate pressure mains (and services when possible) should be installed with consideration for vegetation root growth and its impact on the pipeline. To prevent damage from vegetation root growth the minimum clearance from a tree should be determined by measuring the diameter of the tree (in inches) at a height of 4.5 feet above finish grade and multiplying that value by 1 to 1.5. This value is the critical root zone (in feet) per the International Society of Arboriculture. For example, a tree with a 4 inches in diameter trunk (measured 4.5 feet above grade) will have a critical root zone of 4 feet to 6 feet. For trees that are not fully mature or for special circumstances, the critical root zone should be estimated based on the best available information for that tree species in the region. Small bushes, shrubs, etc. should have at least 5 feet of horizontal clearance from the edge of the gas facilities.

Shoring and Excavating Safety

Avista employees engaging in trenching, excavating, or shoring activities shall follow the procedures outlined in Avista’s Incident Prevention Manual (Safety Handbook). Others contracting work for Avista are required to follow the respective state OSHA requirements. Avista’s Safety Department shall be consulted for excavations greater than 20 feet of depth.

Inspections shall be made of excavations, trenches, adjacent areas, and protective systems by a "competent person" as defined in the Avista’s Incident Prevention Manual (Safety Handbook). Such inspections shall be performed at the start of work and as needed throughout the course of the job in order to determine if conditions exist that could result in a cave-in, failure of protective systems, or other hazardous situations. When the "competent person" finds evidence of a situation that could result in a possible cave-in, failure of protective systems, or other hazardous conditions, exposed employees shall be removed from the area until the necessary precautions have been taken.

Underground utilities that have been located and exposed during the course of the construction or excavation process shall be protected, supported, or removed as necessary to safeguard employees and to prevent damage to the utilities.

Manufactured materials and equipment used for protective systems shall be used and maintained in accordance with the manufacturer's instructions. Any suspected defect in such protective systems shall be reported and corrected before use by any employee.

Trench Excavation

Trenches must be wide enough for installing pipe without damaging coating or inducing unnecessary stresses on the pipe. At horizontal angles, the trench must have sufficient width to accommodate the welding elbow or bend and provide clearance between the side of the trench and the pipe (at least 6 inches on each side for pipe sizes 6-inch and larger).

Examining Buried Pipe

When previously buried steel or plastic pipe is exposed, an Exposed Piping Inspection Report Form (Form N-2534) shall be completed in accordance with Specification 3.44, Exposed Pipe Evaluation.

Padding Material

When the bottom of the trench does not provide for a smooth and firm base for the pipe due to rock, etc. a minimum padding (sometimes referred to as bedding) of 6 inches of cohesive earth or sand with maximum aggregate of 3/4-inch size shall be used. This material may be obtained from screened native soil or by import. This soil should consist primarily of fines and have a minimum of sharp edge aggregate. Soil should be of a nature to allow a firm compacted surface providing uniform support for pipe. Refer to Specification 3.13, Pipe Installation - Plastic (Polyethylene) Mains, "Plowing and Planting" for additional bedding requirements when plowing.

Controlled-Density Backfill

Some jurisdictions may require the use of controlled density backfill (CDF) near gas mains to enhance compaction during roadway construction. Foreign utilities may use CDF material between Avista's gas mains and their facilities when minimum clearances are difficult to achieve. If CDF is used, it shall not be placed directly on the pipe. A minimum of 6 inches of padding (sometimes referred to as bedding) material shall be placed around Avista's mains before CDF material is placed.

When gas pipe is exposed adjacent to other construction / utility projects, the gas pipe shall be sufficiently supported so that no pipe movement occurs. This can be accomplished by strapping, blocking, or other measures as approved by an Avista Inspector or other qualified individual. Care shall be taken to restore original compaction upon backfilling.

Backfill

A backfill of 6 inches using material as described above in Padding Material should be placed over the top of the pipe to prevent damage from rocks while backfilling. If exceptionally large rocks (8 inches or larger) are to be pushed back into the trench, an initial backfill of 12 inches of approved material should be placed over the pipe.

If Caution Tape will be installed at the particular location, it is at this one foot level of cover that the tape should be installed. Reference Specification 3.12, Pipe Installation - Steel Mains, and Specification 3.13, Pipe Installation - Plastic Mains for additional information regarding the use of Caution Tape.

Backfill must provide firm continuous support under and around the pipe. It must be free of sharp objects, rocks, frozen materials, large clods, or any other materials that could be detrimental to the pipe or pipe coating. Materials used for support must be well compacted. Avoid using backfill or supporting materials that could create undue stress or damage to the pipe. To allow for backfill settlement, at casing pipe gaps and where plastic is located on disturbed earth; the pipe should be lifted slightly while the backfill is packed underneath.

Compaction

Compaction levels shall be as specified by the appropriate regulating agency. In general, traveled roadways and improved right of ways require 95 percent compaction. Driveways should be compacted similar to roadways.

Heavily traveled roadways and arterials may have special requirements pertaining to sub-base construction and compaction. Care should be taken to prevent damage to the buried gas facilities when placing and compacting backfill.

Proper compaction should be provided under and around pipe and fittings at branch connections, transitions, service connections, and riser locations to prevent differential settlement even if CDF will be used. This should be accomplished by using hand operated tamping equipment (such as a hand tamper, vibratory plate, whacker, or pogo stick) adjacent to the pipe.

Sand backfill may be placed directly on top of pipe or fittings. A minimum of 12 inches of backfill must be in place before using hand operated tamping equipment directly over the pipe, or a minimum of 18 inches if using equipment mounted compacting devices (such as a hoe-pack, or vibratory roller). A sheep's foot style compactor attached to a backhoe or excavator requires at least 24 inches of cover. Consideration should be made regarding the age of the pipe, operating pressure, and quality of backfill prior to allowing these types of activity over gas mains. When construction activity occurs adjacent to or over existing pipelines and facilities, these same cover requirements apply. If tamping or compaction activities are planned to occur over an existing high pressure main with less than 24 inches of cover, contact Gas Engineering.

Marking Pipe After Installation (OR)

In areas of ongoing excavation or construction (such as residential or commercial site development) in Oregon, newly installed facilities shall be located and marked with locate paint or appropriate flagging for backfilled facilities immediately upon placement. For shaded pipe in a ditch where Avista is not backfilling the ditch, locate and mark using locate paint on the sand or "natural gas" caution/marking tape which may be placed on the sand over the pipe using sand in various places to anchor the tape in place so that the location of the pipe is still visible. (This is a requirement in Oregon per OAR 952-001-0070 (8)).

Pressure Testing After Backfilling

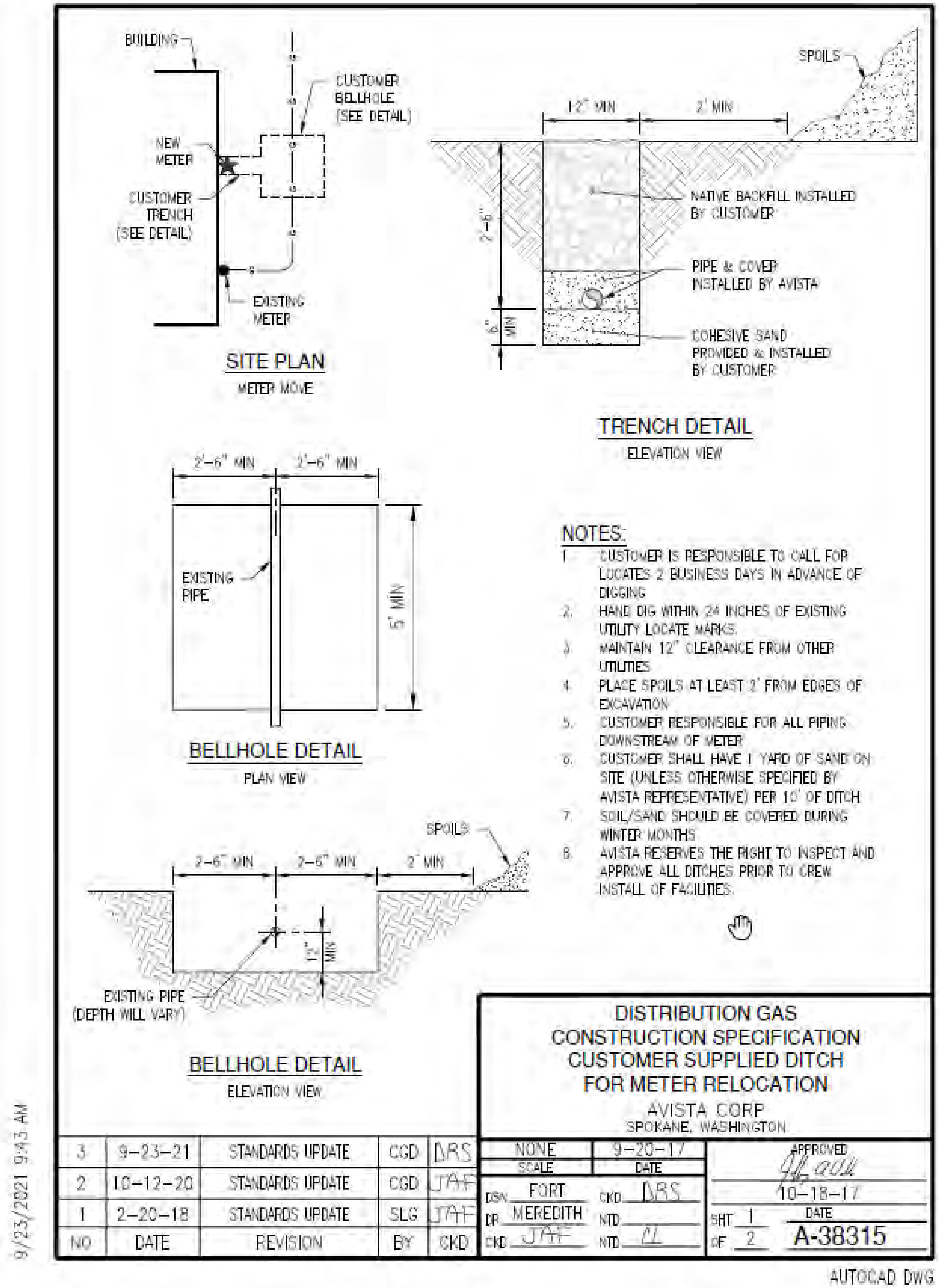
Where feasible, plastic pipe must be installed and backfilled prior to pressure testing to bring attention to any potential damage that may occur during the installation and backfill process. Pre-tested pipe may only be used where it is not feasible to conduct a post construction pressure test.

Pipeline Markers

For further guidance, refer to Specification 5.15, Pipeline Patrolling and Pipeline Markers, in subsections "Pipeline Markers for Buried Pipe", "Exceptions for Marking," "Washington Pipeline Marker Requirements," and "Markers for Aboveground Pipelines."

Customer Trench / Ditch Detail Drawings

(See following pages)


BUILDING
CUSTOMER BELLHOLE (SEE DETAIL)
NEW METER
CUSTOMER TRENCH (SEE DETAIL)
EXISTING METER
SITE PLAN
METER MOVE
SPOILS
12" MIN
2' MIN
2'-6"
6" MIN
NATIVE BACKFILL INSTALLED BY CUSTOMER
PIPE & COVER INSTALLED BY AVISTA
COHESIVE SAND PROVIDED & INSTALLED BY CUSTOMER
TRENCH DETAIL
ELEVATION VIEW
2'-6" MIN
2'-6" MIN
EXISTING PIPE
5' MIN
BELLHOLE DETAIL
PLAN VIEW
NOTES:
1. CUSTOMER IS RESPONSIBLE TO CALL FOR LOCATES 2 BUSINESS DAYS IN ADVANCE OF DIGGING
2. HAND DIG WITHIN 24 INCHES OF EXISTING UTILITY LOCATE MARKS.
3. MAINTAIN 12" CLEARANCE FROM OTHER UTILITIES
4. PLACE SPOILS AT LEAST 2' FROM EDGES OF EXCAVATION
5. CUSTOMER RESPONSIBLE FOR ALL PIPING DOWNSTREAM OF METER
6. CUSTOMER SHALL HAVE 1 YARD OF SAND ON SITE (UNLESS OTHERWISE SPECIFIED BY AVISTA REPRESENTATIVE) PER 10' OF DITCH
7. SOIL/SAND SHOULD BE COVERED DURING WINTER MONTHS
8. AVISTA RESERVES THE RIGHT TO INSPECT AND APPROVE ALL DITCHES PRIOR TO CREW INSTALL OF FACILITIES.
SPOILS
2'-6" MIN
2'-6" MIN
2' MIN
12" MIN
EXISTING PIPE (DEPTH WILL VARY)
BELLHOLE DETAIL
ELEVATION VIEW
DISTRIBUTION GAS
CONSTRUCTION SPECIFICATION
CUSTOMER SUPPLIED DITCH
FOR METER RELOCATION
AVISTA CORP
SPOKANE, WASHINGTON
3 9-23-21 STANDARDS UPDATE CGD DRS
2 10-12-20 STANDARDS UPDATE CGD JAF
1 2-20-18 STANDARDS UPDATE SLG JAF
NO DATE REVISION BY CKD
NONE SCALE
9-20-17 DATE
DSN FORT CKD DRS
DR MEREDITH NTD
CKD JAF NTD
APPROVED
10-18-17 DATE
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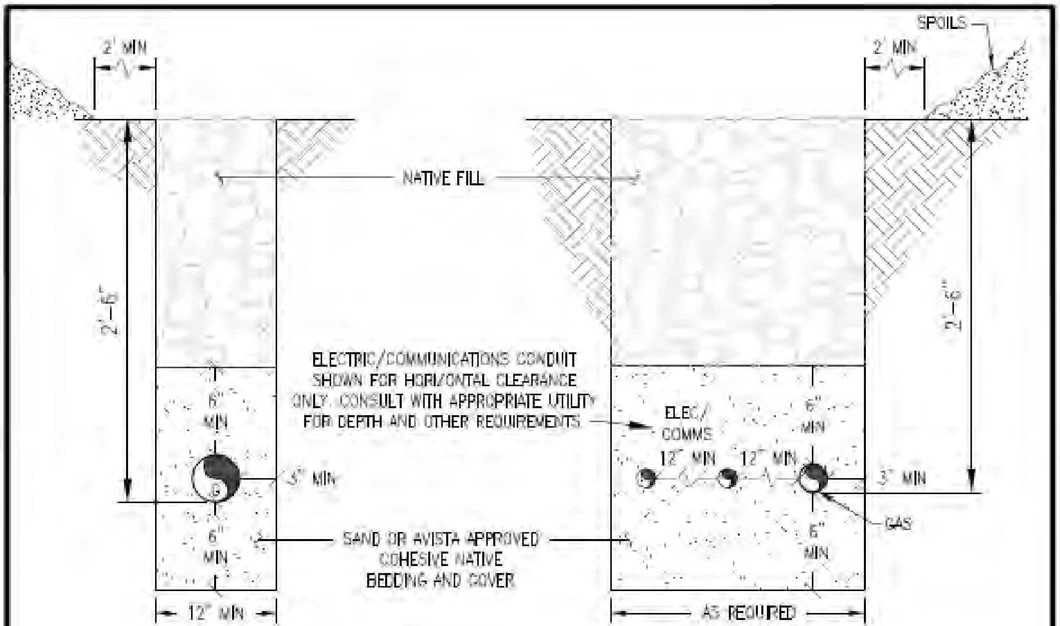

SERVICE TRENCH DETAIL

JOINT USE UTILITY TRENCH DETAIL

NOTES:

1. CUSTOMER IS RESPONSIBLE TO CALL FOR LOCATES 2 BUSINESS DAYS IN ADVANCE OF DIGGING.
2. HAND DIG WITHIN 24 INCHES OF EXISTING UTILITY LOCATE MARKS.
3. ALL CUSTOMER DITCHES MUST PASS AVISTA INSPECTION.
4. A MINIMUM SEPARATION OF 10' (25' PREFERRED) FROM SEWER DRAIN LINES AND LEECH FIELDS SHOULD BE MAINTAINED. PLASTIC PIPE SHALL NOT BE INSTALLED THROUGH, ABOVE, OR BELOW DRAIN FIELDS.
5. GAS PIPE SHALL HAVE A MINIMUM OF 3' SEPARATION FROM WATER AND 5' SEPARATION FROM SEWER. GAS PIPING SHOULD NOT BE INSTALLED IN THE SAME TRENCH WITH WATER OR SEWER.
6. PLASTIC PIPE SHOULD BE INSTALLED WITH A MINIMUM OF 12" OF CLEARANCE FROM CULVERTS.
7. TRENCH SHALL ALLOW FOR AT LEAST 12" RADIAL SEPARATION FOR ANY UTILITY CROSSINGS.
8. A MINIMUM BEDDING AND PADDING OF 6" OF COHESIVE SAND SHALL BE USED WHEN NATIVE MATERIAL IS NOT SUITABLE (NATIVE MATERIAL MUST BE APPROVED BY AVISTA REPRESENTATIVE). NATIVE FILL SHALL BE FREE OF RUBBISH, CINDERS, CHEMICAL REFUSE, ROCK LARGER THAN 4", OR OTHER MATERIALS THAT COULD CAUSE DAMAGE TO THE PIPE.
9. SOIL/SAND SHOULD BE COVERED DURING WINTER MONTHS.
10. TRENCH SHOULD ALLOW A MINIMUM OF 5' SEPARATION FROM AN EXISTING BUILDING FOUNDATION.
11. FINAL GRADE SHOULD BE WITHIN 6" FROM TOP OF DITCH.
12. AVISTA RESERVES THE RIGHT TO INSPECT AND APPROVE ALL DITCHES PRIOR TO CREW INSTALL OF FACILITIES.

DISTRIBUTION GAS
CONSTRUCTION SPECIFICATION
PE NATURAL GAS SERVICE
CUSTOMER PROVIDED TRENCH DETAIL
AVISTA CORP
SPOKANE, WASHINGTON

NO	DATE	REVISION	BY	CKD
4	9-23-21	STANDARDS UPDATE	CGD	DRS
3	10-12-20	STANDARDS UPDATE	CGD	JAF
2	9-10-20	STANDARDS UPDATE	CGD	JAF
1	2-20-18	STANDARDS UPDATE	SLG	JAF

AS SHOWN (SCALE)	9-25-17 (DATE)	APPROVED
DSN FORT	CKD DRS	10-18-17 (DATE)
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3.16 SERVICES

SCOPE:

To establish uniform procedures for designing, locating, and installing natural gas services.

REGULATORY REQUIREMENTS:

§192.361, §192.363, §192.365, §192.367, §192.371, §192.375, §192.381, §192.383, §192.385, §192.725

WAC 480-93-100, 480-93-115

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design - Steel
Spec. 2.13, Pipe Design - Plastic
Spec. 2.14, Valve Design
Spec. 3.13, Pipe Installation – Plastic Mains
Spec. 3.15, Trenching and Backfilling
Spec. 3.18, Pressure Testing
Spec. 5.16, Abandonment or Inactivation of Facilities

INSTALLATION REQUIREMENTS:

General

New or re-commissioned services shall be tested to the pressures required for a new line installation. Refer to Specification 3.18, Pressure Testing.

Location Considerations

Consideration shall be given to the location of the service and riser so that each meter and service regulator, whether inside or outside of a building, is installed in a readily accessible location and protected from corrosion and other damage, including vehicular damage that may be anticipated.

Service lines should be run directly to the meter at right angles to the main and property line. Services should not be run under existing or proposed driveways or patios unless there is no alternate route. Consideration should also be given to the future probable location(s) of egress windows when installing service lines in close proximity to homes.

If condensates are present in the gas where it might cause interruption in the gas supply to the customer, the service line must be sloped so condensates will drain toward the main or into drips at the low points in the service line.

Service lines must be installed to minimize anticipated piping strain / external loading.

See Spec 3.13 – “Pipe Installation – Plastic Mains” for additional considerations related to field bending of PE pipe.

See Spec 3.15 – “Trenching and Backfilling” for additional considerations related to clearances.

New Plastic Services

When installing a new plastic service near, equal to, or exceeding 1,000 feet in length, a 4-1/2 lb. zinc anode should be installed to prevent corrosion of the tracer wire. Install one anode near the main and install any additional anodes at 1,000-foot spacings toward the service riser. (Refer to Specification 3.13, Tracer Wire, for further guidance.)

Steel Service Replacement

When replacing or repairing sections of steel service, care must be taken to maintain cathodic protection (CP) as well as the ability to locate the pipe. Below is a hierarchy of preferences when replacing all or a portion of a steel service:

1. Convert the service to polyethylene plastic (PE) the full length from the main to the meter for the betterment of the gas system to prevent isolated steel locations and to prevent disbonded dresser fittings.
2. In situations where only a portion of the service is to be replaced or repaired, install new steel pipe to maintain CP continuity. An example of this is offsetting a steel service for installation of a window well.
3. Replace the service from the riser back as far as practical using PE pipe and install a transition fitting before reaching the main. A stress relieving sleeve should be installed at the steel to PE transition point prior to completion of the service connection. Refer to Spec 2.13 – "Joining of Plastic Pipelines". The following must also be completed in this scenario:
    a. Install a marker ball at the transition.
    b. Install tracer wire from the transition to the riser.
    c. Note accurate centerline measurements of the exact location of the transition on the appropriate work order.

Excess Flow Valves

An excess flow valve (EFV) is a device that is designed to automatically shut off the flow of gas should the service line be severed. An EFV shall be installed in any of the following circumstances where the operating pressure is 10 psig or greater:

- On each newly installed or replaced service line serving a single family residence.
- On each newly installed or replaced service line serving a multifamily residence when the meter capacity, at the time of meter installation, is under 1,000 CFH; and
- On each newly installed or replaced service line serving a small commercial facility when the capacity, at the time of meter installation, is under 1,000 CFH; and
- On each newly installed or replaced branched service line if an EFV does not already exist. The EFV should be installed so that it protects both services on a branched service.

    NOTE: Refer to "Replaced Service Line" in Specification 1.1, Glossary, for a detailed definition.

As noted in §192.383, customers have a right to request an EFV on service lines not exceeding 1000 SCFH and who are not exempt from needing to have one as discussed below. Avista is required to notify customers regarding their right to request an EFV and will do so via its website and / or through periodic monthly bill inserts. Avista is required to keep evidence of such notifications, present such evidence if asked during pipeline safety inspections and provide EFV reporting on its Distribution Annual Report required by §191.11.

Although not explicitly required, consideration should be given to installing an EFV when a service line is exposed near the main and an opportunity to install an EFV exists. Additionally, the EFV must be marked, or its presence be identified on the service line and must be located as close to the fitting connecting the service line to the main as practical.

Where an EFV is **not** required to be installed:

- Service points with existing loads above 1000 CFH where an EFV is not sufficient or not practical. In these cases, however, a curb valve shall be installed on new or replaced services lines. (Refer to Specification 2.14, Valve Design, "Curb Valves" for more information.). EFVs are preferred if they are able to meet the flow requirements of the service.
- Industrial services.
- An EFV meeting the performance standards, as specified in 49 CFR 192.381, is not commercially available.
- Systems that operate at a pressure of less than 10 psig.
- Service lines where there have been prior problems with contaminants in the gas stream that could cause the EFV to malfunction or interfere with the removal of liquids from the line for necessary maintenance.

Criteria for determining when to use an EFV or curb valve

	Single-Family Residence	**Multifamily Residences**		**Commercial Customers Served by a Single Service Line**	
	Any Meter Capacity	**Installed Meter Capacity ≤ 1,000 SCFH**	**Installed Meter Capacity > 1,000 SCFH**	**Installed Meter Capacity ≤ 1,000 SCFH**	**Installed Meter Capacity > 1,000 SCFH**
Operating Pressure < 10 PSIG	Nothing Required	Nothing Required	Install Curb Valve	Nothing Required	Install Curb Valve
Operating Pressure ≥ 10 PSIG	Install EFV*	Install EFV*	Install EFV or Curb Valve	Install EFV*	Install EFV or Curb Valve

*Subject to exceptions listed above this table.

The excess flow valves are available in three styles:

1. PE bolt-on service tee with EFV incorporated into the outlet.
    a. To be used on new PE services.

2. In-line "stick" EFV.
    a. For use on existing PE stubs. Locate EFV at road right-of-way line.
    b. For use off of steel main downstream of the transition fitting.

3. Mechanical coupling with built in EFV.
    a. For use on existing PE stubs. Locate EFV at road right-of-way line.
    b. For use off of steel main downstream of the transition fitting.

Individuals designing services shall use the following charts under Capacity of EFV to determine which EFV to install based on the customer's projected load. The design that goes to construction shall indicate if an EFV is to be installed based on the requirements of this specification. The EFV symbol shall be shown in Avista's AFM (GIS) system. This enables Avista to run reports on the number of excess flow valves installed in the system on a yearly basis.

The following table shows EFV symbology in AFM.

Symbol	Description
	Stick EFV
	Tapping tee with integrated EFV
	Inline Tee with EFV
	Reducer Inline Tee with EFV
	Reducer Coupling with EFV

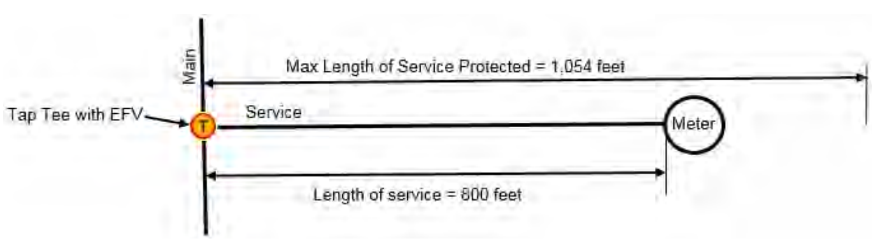
Capacity of EFV

The following tables are used to size the EFV based on the lowest pressure (psig) the service line will operate and the minimum trip rate in cubic feet per hour (CFH). Designers should use 10 psig in the tables as the lowest pressure the service line will operate at, unless the system operates at a pressure lower than 10 psig.

The smallest capacity (not length) EFV capable of managing the anticipated load shall be selected, unless there are extenuating circumstances. In such cases, contact Gas Engineering for assistance. If the projected load exceeds the capacity of the EFV in the following tables at 10 psig, select a higher capacity EFV or install a curb valve. A higher capacity EFV may need to be specified and special ordered in certain applications.

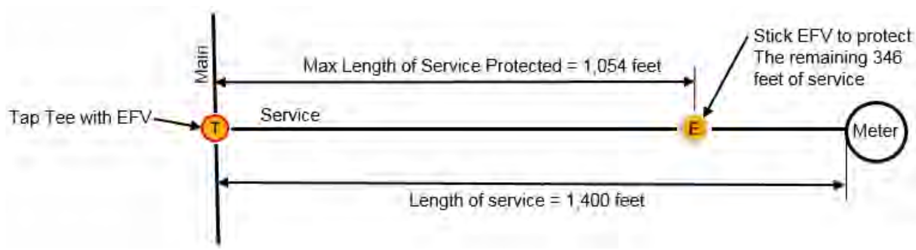
"Maximum Length of Service Protected" in the last column of the tables is the maximum distance from where the excess flow valve is located that it will trip at the minimum flow rate if the service line were damaged.

EXAMPLE: If a service line is 800 feet in length at a pressure of 10 psig, a tap tee with integrated 775 EFV would protect 1,054 feet of service line. This EFV provides adequate protection. See diagram below.



If the length of the service line is longer than the max length of service protected listed in the table, install a second EFV in the service to protect the remaining length of service.

EXAMPLE: If a service line is 1,400 feet in length at a pressure of 10 psig, a tap tee with integrated 775 EFV would protect the first 1,054 feet of service line. If the damage occurs beyond 1,054 feet, the excess flow valve may not trip. In this scenario, a stick EFV can be installed to protect the remaining 346 feet of service line. See diagram below.



When an existing customer load is increased and the service line has an EFV, the EFV capacity must be evaluated and the EFV upsized if necessary.

EFV Capacity Tables

775 CFH, LYCO EFV II SERIES, ½"		
Inlet Pressure (psig)	Min Trip Flow Rate (CFH)	Max Length of Service Protected (ft)
5	692	8
10*	**775**	**34**
15	850	57
20	919	80
25	983	102
30	1,044	124
35	1,101	146
40	1,155	168
45	1,206	190
50	1,256	211
55	1,304	233
60	1,350	255
Grayed area to assist in troubleshooting *Note: 10 psig is recommended for determining the appropriate EFV		

775 CFH, LYCO EFV I SERIES, ¾"		
Inlet Pressure (psig)	Min Trip Flow Rate (CFH)	Max Length of Service Protected (ft)
5	692	446
10*	**775**	**1,054**
15	850	1,619
20	919	2,163
25	983	2,694
30	1,044	3,220
35	1,101	3,742
40	1,155	4,262
45	1,206	7,782
50	1,256	5,303
55	1,304	5,824
60	1,350	6,347
Grayed area to assist in troubleshooting *Note: 10 psig is recommended for determining the appropriate EFV		

1200 CFH, LYCO EFV I SERIES, ¾”		
Inlet Pressure (psig)	Min Trip Flow Rate (CFH)	Max Length of Service Protected (ft)
5	1071	116
10*	**1200**	**388**
15	1316	642
20	1423	887
25	1523	1127
30	1616	1364
35	1704	1600
40	1788	1835
45	1868	2071
50	1945	2306
55	2019	2543
60	2090	2780
Grayed area to assist in troubleshooting *Note: 10 psig is recommended for determining the appropriate EFV		

1800 CFH, LYCO EFV I SERIES, ¾”		
Inlet Pressure (psig)	Min Trip Flow Rate (CFH)	Max Length of Service Protected (ft)
7	1672	8
10*	**1800**	**78**
15	1998	185
20	2183	285
25	2356	382
30	2520	476
35	2676	568
40	2826	659
45	2790	749
50	3109	838
55	3244	926
60	3375	1013
Grayed area to assist in troubleshooting *Note: 10 psig is recommended for determining the appropriate EFV		

The RW Lyall 475, 3/4-inch EFVB, stick style was used up through the year 2007 and the following table is used for troubleshooting only. This model EFV is no longer being installed as of 1/1/2008.

TROUBLE SHOOTING TABLE ONLY EFV STICK, ¾", 475 CFH, RW LYALL LYCO EFV I SERIES		
Inlet Pressure (psig)	Min Trip Flow Rate (CFH)	Max Length of Service Protected (ft)
5	424	1,395
10	475	2,875
15	521	4,249
20	563	5,569
25	603	6,859
30	640	8,132
35	675	9,397
40	708	10,657
45	739	11,917
50	770	13,177
55	799	14,439
60	827	15,704

Branch (Split) Service

A branch or split service is a distribution line that transports gas from a common source service of supply to two adjacent or adjoining residential or small commercial customers. Branch services may be initiated near an adjacent property owner's meter provided the adjacent customer's written approval is obtained to work on their property, otherwise a branch can be done at the curb within the public right-of-way. The advantage of a branch is to avoid cutting asphalt or concrete. A branch service should only be installed when both the existing and new services are located on the adjacent, nearby sides of the structure, not the far side of either.

Branching of an existing branched service (thereby creating more than two service points on a branched arrangement) shall not be done to add another residential or commercial load. Branching off of an existing branched service line to add a small, metered load such as a shop, swimming pool, etc. may be allowed if approved by Gas Engineering. Considerations such as total connected load, the depth of the existing service line that will be reclassified as a main line, and the length of time of the original pressure test(s) of the existing service line that will be reclassified as a main line must be considered before approval is granted.

When branching off of an existing service, an EFV should be installed such that it protects both downstream services, unless there are extenuating circumstances such as those listed earlier in this specification in the subsection entitled "Excess Flow Valves". If the existing service already has an EFV installed, the new capacity of the combined customer loads must be evaluated and the EFV upsized if necessary. Consideration when designing branch services in regard to excess flow valves:

1. If the combined load of the branch services exceeds the specified CFH in the EFV sizing tables based on the minimum operating system pressure (10 psig), then separate services shall be run on residential homes.

2. Large custom home areas may necessitate separate services.

A 1/2-inch service should not be split or branched due to potential capacity issues.

Installation of Excess Flow Valves

The excess flow valve (EFV) is a precision device and should be handled with care. Excessively rough handling and/or the allowing of dirt, sand, or other debris to enter the EFV carrier (tee, stick, or coupling) could cause damage to the device, rendering it inoperable.

The following are procedures for installing and putting a service with an excess flow valve into operation by style of EFV:

Excess Flow Valve (EFV) Installation Procedure – Service Tee Style:

The following procedure is to be used when installing a service tee style excess flow valve (EFV):

1. Run service line and install riser. Install EFV identification washer on riser, immediately below the service valve.
2. Use air compressor to purge debris out of service line prior to installing and connecting to the service tee.
3. Perform pressure test on entire service line back to the service tee using standard testing procedures.
4. Ensure that the EFV is not tripped by observing the pressure gauge for a slow, steady rise in pressure. If the pressure “bumps” or rises quickly, the EFV is probably tripped. Shut off air and allow the EFV to reset and equalize the pressure in the service line. Resume pressurization while observing the pressure gauge.
5. Pressurize the service line to the proper test pressure (90 psig minimum) and observe for pressure drops. The length of the test is determined by the table in Specification 3.18, Pressure Testing.
6. When test is complete, slowly bleed the pressure off at the main.
7. Tap the main, back off the tap slowly to avoid tripping the EFV.
8. Purge the service line of air at the riser. A test regulator with a 1/8-inch orifice or a 90-degree elbow with cap that has 1/8-inch drilled orifice may be used to control flow and avoid tripping the EFV. Orient the purging device in a safe direction for gas flow. Fully open service valve at riser slowly to avoid tripping the EFV. If the EFV trips, close the service valve and allow the bypass gas to equalize, this resets the EFV. Use a combustible gas indicator to check for 93 percent gas or higher. For additional information, refer to Specification 3.17, Purging Pipelines, “Purging Services.”
9. Set the meter and purge slowly. Do not free-flow the meter unrestricted as this could trip the EFV.
10. Record the EFV data on the As-built and/or service card.

Excess Flow Valve (EFV) Installation Procedure – In-Line Stick or Coupling Style:

For use off of steel main, existing service stub, and when branching off of an existing service that does not already have an excess flow valve. Refer to Standard Unit Assembly Drawing A-37169 at the end of this specification for EFV installations from an existing steel service tee. Note: Prior to completing the connection of the EFV to the steel tee be sure to install a stress-relieving sleeve on the service line that will help protect the rigid steel to PE transition per the requirements in Spec 2.13 – “Joining of Plastic Pipeline Components”.

1. Run service line and install riser. Install identification washer on riser, immediately below the service valve.
2. Use air compressor to purge debris out of service line prior to installing EFV.
3. Connect EFV stick or coupling in proper position (with arrow pointing away from source of gas) with mechanical fittings to the stub or steel service tee in the bell hole depending on which type of connection is being made.
4. Perform pressure test on the service line, including the EFV, using standard testing procedure.
5. Ensure that the EFV is not tripped by observing the pressure gauge for a slow, steady rise in pressure. If the pressure “bumps” or rises quickly, the EFV is probably tripped. Shut off air and allow the EFV to reset and equalize the pressure in the service line. Resume pressurization while observing the pressure gauge.
6. Pressurize the service line to the proper test pressure (90 psig minimum) and observe for pressure drops. The length of the test is determined by the table in Spec 3.18 Pressure Testing.
7. When test is complete, slowly bleed the pressure off.
8. (Tap the main or make final connection), back off the tap or squeezer slowly to avoid tripping the EFV.
9. Purge service line of air at the riser. A test regulator with a 1/8-inch orifice or a 90-degree elbow with cap that has 1/8-inch drilled orifice may be used to control flow and void tripping the EFV. Orient the purging device in a safe direction for gas flow. Fully open service valve at riser slowly to avoid tripping the EFV. If the EFV trips, close the service valve and allow the bypass gas to equalize, this resets the EFV. Use a combustible gas indicator to check for 93 percent gas or higher. For additional information, refer to Specification 3.17, Purging Pipelines, “Purging Services.”
10. Set the meter and purge slowly. Do not free-flow the meter unrestricted as this could trip the EFV.
11. Record the EFV data on the As-built and/or service card.

EFV – High Pressure Services

A high-pressure service is defined as a steel service line carrying pressure in excess of 60 psig up to a customer. In general, it is desired to minimize the installation of high-pressure services. It is preferred to design intermediate distribution systems and serve customers with intermediate pressure.

When it is necessary to install a high-pressure service, the service shall be installed utilizing a Mueller Autosafe Model H-17842 Curb Valve Tee at the main. This valve tee operates with a ball check (EFV) and is designed to shut off at flows exceeding 500 CFH. No exceptions are to be made without concurrence by Gas Engineering.

Not more than one customer shall be served off a high-pressure service (i.e., no branching). Should it be necessary to branch the existing high-pressure service, a regulator station or “farm tap” type regulator station must be installed near the main.

High-pressure service designs shall be reviewed by Gas Engineering.

Service Risers

Service risers should be installed a minimum of 8 inches from the finished building wall with the service termination valve approximately 10 inches from ground level or finished grade to accommodate proper riser installation (refer to the drawings in Specification 2.24).

For installation in heavy snow areas refer to Sheets 8 and 17 of this specification. The service valve should be positioned so that the shut off is facing away from the building or the meter and easily accessible for operation. The service valve and meter shall not be in contact with the ground except for applications detailed in Drawings A-36712 and C-35209 in Specification 2.24. Variance to these requirements must be approved by Gas Engineering.

The service riser and tracer wire (if applicable) shall be installed through a 4-inch diameter, or larger, non-metallic sleeve (i.e., PVC or corrugated drainpipe). The sleeve should be installed to a depth of 12-18 inches below grade and extend to a height 3-4 inches above grade. The sleeve once positioned, is filled with soil.

The purpose of setting the sleeve above grade is to prevent eventual accumulation of debris around the riser and assure future concrete, pavement or other customer improvements do not contact the riser. It also provides an opening around the riser that aids in leak survey and detection as well as provides access to take a cathodic pipe-to-soil reading.

The PE "pigtail" on anodeless service risers may be shortened, if necessary, to accommodate unique installation requirements. The steel portion of the riser may be rethreaded in the event the threads are damaged as long as the riser nipple is Schedule 80, and the original threads are completely removed before rethreading. Schedule 40 risers may not be rethreaded. No other modifications are allowed to the steel portion of the riser.

Service Risers for Multi-Meter Manifolds

Service risers for multi-meter manifolds should be installed a minimum of 12 inches from the finished building wall.

Services in Heavy Snow Areas

Location of the riser and meter set shall be on a non-shed side of the roof, where possible. On new installations, approved external meter protection and a breakaway fitting should be installed to protect the meter from falling snow and ice. Refer to Specification 2.22, Meter Design, "Meter Set Location Protection and Barricades" and "Breakaway Fitting" for further guidance. If a suitable site cannot be found, an inside meter installation may be considered. (Contact Gas Engineering for approval before installing an inside meter). On meter sets installed inside a structure to avoid snow loads, the service valve should be installed approximately 6 feet aboveground, level to the riser, and anchored to the wall per Drawing B-36269.

Service Lines in Conduit / Casing

When it is necessary to install a service line in a conduit/casing, the end nearest the building wall must be sealed to prevent or slow the migration of gas towards the building in the event of a leak in the service piping. This end seal may be made with expansion foam or other suitable seal. This is required not only in Washington (per WAC 480-93-115(4)) but also in Oregon and Idaho.

WAC 480-93-115 (4): Whenever a gas pipeline company installs a service line in a casing or conduit, the gas pipeline company must seal the casing at the end nearest the building wall to prevent or slow the migration of gas towards the building in the event of a leak.

Service Lines into Buildings

The service line or service riser should not pass through a concrete wall, floor slab, or a foundation wall without design approval by Gas Engineering.
Each underground service line that enters a building below grade must:

- In the case of a metal service line, be protected against corrosion,
- In the case of a plastic service line, be protected from shearing action and backfill settlement and a steel anodeless riser be used (either prebuilt or “new construction”) where it enters the building wall,
- Enter into a normally usable and accessible part of the building, and
- Be encased in a gas-tight conduit as it passes through the foundation or floor.

The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting. If the service is steel, it is best to have a bare steel conduit with spacers installed to ensure the carrier pipe does not short to the conduit.

Service Lines Passing Under Buildings

The installation of service lines underground under buildings should be performed only as a last resort and only after prior approval from Gas Engineering. Service lines installed under buildings must be cased, sealed, and vented to the outside atmosphere.

Main Connections

Each service line connection to a main should be located at the top of the main to prevent dust, shavings, and debris from entering the service line. If connection to the top of the main is not practical, then the service may be connected to the side of the main using approved fittings. A main shall not transition directly to a service without use of a service tee or means of delineating the service from the main.

Service connections to main by use of compression-type fittings must be designed and installed to effectively sustain the longitudinal pullout, or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading. If gaskets are used in connecting the service line to the main connection fitting, they must be compatible with the gas in the system.

Curb Valves

Underground service valves or “curb valves” shall be installed on all services where meter sets are installed in buildings or where it is impossible to provide ready access to a service line valve at an outside wall of a building. A curb valve shall also be installed on all new or replaced service lines where the load is greater than 1000 CFH and an EFV is not practical for installation. For additional criteria of where curb valve shall be installed refer to Specification 2.14, Valve Design, “Curb Valves.”

Insertion of Old Steel Services Along Steel Main

Insertion should be done only as a last resort when open trenching is too costly. In these cases, it is often possible to pull short services that are reasonably straight out of the ground and pull new plastic pipe and tracer wire through the void left by the steel service pipe that is removed. Pulling force limitations on plastic pipe shall be monitored and adhered in accordance with Specification 3.13, Pipe Installation - Plastic Mains.

When insertion of an old steel service is to be performed off steel main, electrical continuity should be maintained along the service. This shall be performed as shown in Drawing A-34735 at the end of this specification. The tracer wire shall be cadwelded to the main near the old steel service and the other end of the tracer wire shall be cadwelded to the steel service being inserted.

Insertion of Old Steel Services Along Plastic Main

When an old steel service is to be inserted and new plastic main is to be run, the electrical continuity of the service should be maintained. In order to accomplish this, splice the tracer wire at the main and perform a Cadweld to the steel service being inserted. The cadwelding process must be done prior to inserting the plastic pipe inside.

New, smaller diameter PE shall not be inserted into existing PE main or service unless the old pipe has been split open (as in a pipe-replacement project) without Gas Engineering's approval.

Service – Termination Valve

The service termination valve shall be the first exposed threaded fitting aboveground other than a service head adapter for field fabricated risers. The valve shall be one of the following types:

- On steel services, an insulated type, with the insulating portion on the outlet side of the valve.
- On plastic services, a non-insulating type valve may be used; however, the insulated valve is preferred.

Unless a meter set assembly is to be immediately installed, the service valve shall be locked off and an 8-inch idle riser nipple and cap assembly shall be installed or alternatively an approved meter bar. A gas warning sticker (Stock Item Number 662-0426 or 662-0428) shall be applied to the assembly to help prevent future damage to the service riser.

Steel Service Abandonment

Refer to Specification 5.16, Abandonment or Inactivation of Facilities, for further guidance on steel service abandonment.

New Service Lines Not in Use

Each service line that is not placed in service upon completion of installation must comply with one of the following until the customer is supplied with gas:

- The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by unauthorized persons.
- A mechanical device or disc that will prevent the flow of gas must be installed in the service line or in the meter assembly.
- The customer's piping must be physically disconnected from the gas supply and the open ends sealed.

Service Lines to Recreational Vehicles

Service lines shall not be installed to any type of recreational vehicle including but not limited to motor homes, travel trailers, and campers.

Service Lines to Floating Structures

If a gas service is being installed to serve a floating structure, Avista’s service line and MSA must be installed and terminate on solid ground or a solid structure on shore. These types of meters would be considered a “Remote Meter Set”. See additional requirements for these meters in Specification 2.22, Metering & Regulation, Meter Set Location, Protection and Barricades.

Service Pipe Capacities

The following table may be utilized in sizing natural gas services. The tables provide maximum flow rates in SCFH for various lengths, sizes, and piping materials with inlet pressure of 15 psig. Flows are given assuming a 5 psig drop in pressure from the beginning of the service (inlet from main) to the end of service (inlet of the meter). Contact the Gas Planning Department for guidance in situations where the design criteria fall outside of the parameters of the table.

	Plastic (roughness = 0.000060)							Steel (roughness = 0.00180)				
	1/2"	3/4"	1-1/4"	2"	3"	4"	6"	3/4"	1-1/4"	2"	4"	6"
Length (ft)	CTS	IPS	IPS	IPS	IPS	IPS	IPS	Std.	Std.	Std.	Sch. 10	Sch. 10
20	1,513	9,059	27,150	75,300	213,700	414,300	1,140,000	6,443	25,131	72,717	444,231	1,315,231
40	1,031	6,207	18,660	51,890	147,600	286,600	790,400	4,524	17,679	51,208	313,257	928,002
60	822	4,968	14,960	41,670	118,700	230,700	637,100	3,675	14,379	41,683	255,244	756,476
80	700	4,240	12,790	35,650	101,700	197,700	546,400	3,169	12,413	36,008	220,669	654,238
100	617	3,748	11,310	31,570	90,140	175,400	485,000	2,825	11,072	32,136	197,077	584,476
125	544	3,313	10,010	27,960	79,880	155,500	430,300	2,516	9,874	28,674	175,981	522,087
150	492	2,994	9,055	25,310	72,360	140,900	390,200	2,289	8,989	26,119	160,411	476,039
175	450	2,749	8,318	23,260	66,550	129,600	359,100	2,113	8,303	24,135	148,313	440,256
200	418	2,552	7,727	21,620	61,880	120,600	334,200	1,970	7,749	22,536	138,563	411,416
300	322	2,035	6,175	17,310	49,610	96,760	268,500	1,593	6,280	18,289	112,661	334,791
400	282	1,733	5,265	14,770	42,390	82,730	229,800	1,369	5,406	15,762	97,232	289,136
500	248	1,529	4,651	13,060	37,520	73,250	203,600	1,217	4,811	14,039	86,710	257,994
1000	167	1,035	3,159	8,894	25,630	50,130	139,700	841	3,339	9,776	60,643	180,806
1500	132	823	2,517	7,130	20,490	40,110	111,900	675	2,692	7,897	49,128	146,679
2000	111	699	2,141	6,051	17,480	34,230	95,620	578	2,308	6,781	42,280	126,371

Pipe Sizes and Capacities Downstream of Meter

As a matter of standard practice, Avista personnel should not design customer piping systems downstream of the meter. As Avista does not own or maintain stream of customer piping, liability may be incurred by Avista if we design a customer's piping system. Avista's Account Representatives have been provided a list of professional engineering consultants that responded to a request for qualifications solicitation by Gas Engineering to design downstream gas piping for customers. Contact the applicable Account Representative for your area should you need to refer to the aforementioned list.

It is sometimes necessary, when working with customers to verify their piping systems are adequate to meet their load requirements. For this reason, the following tables are provided. The tables give maximum flows for various lengths, sizes, and piping materials with inlet pressures from regulation of 5.0 psig, 2.0 psig, or 7.0-inch WC (water column). Pressure drop allowed from beginning to end of pipe (Delta P) are shown for each table.

Pipe Capacities - Downstream of Meter

Flow in CFH for various lengths, sizes, and piping material

Based on 0.60 S.G. & 95% efficiency factor to account for equiv. length of pipe for fittings

P1 = 2.0 psig
P2 = 1.5 psig
Delta P = 0.5 psig

	Plastic (roughness = 0.000060)						
	1/2"	3/4"	1-1/4"	2"	3"	4"	6"
Length (ft)	CTS	IPS	IPS	IPS	IPS	IPS	IPS
20	314	1,926	5,846	16,392	47,004	91,692	254,561
40	211	1,306	3,977	11,182	32,151	62,817	174,793
60	167	1,039	3,171	8,932	25,722	50,304	140,162
80	142	883	2,699	7,612	21,947	42,951	119,791
100	125	778	2,381	6,723	19,401	37,988	106,030
125	110	685	2,100	5,936	17,147	33,592	93,833
150	99	618	1,895	5,361	15,498	30,377	84,904
175	90	566	1,737	4,918	14,227	27,896	78,014
200	83	524	1,611	4,564	13,210	25,910	72,494
300	66	416	1,281	3,635	10,541	20,696	57,992
400	58	352	1,087	3,091	8,977	17,640	49,480
500	54	310	958	2,726	7,924	15,580	43,740
1000	42	207	644	1,841	5,371	10,581	29,786
1500	31	164	510	1,462	4,274	8,430	23,772
2000	23	138	432	1,240	3,632	7,172	20,249

	Steel (roughness = 0.00180)						
	3/4"	1"	1-1/4"	2"	3"	4"	6"
Length (ft)	**Std.**	**Std.**	**Std.**	**Std.**	**Std.**	**Sch. 10**	**Sch. 10**
20	1,513	2,879	5,965	17,378	49,221	107,100	318,335
40	1,048	1,999	4,151	12,127	34,428	75,025	223,399
60	843	1,611	3,351	9,809	27,892	60,845	181,403
80	722	1,381	2,876	8,432	24,005	52,408	156,401
100	640	1,225	2,553	7,494	21,358	46,659	139,359
125	567	1,086	2,266	6,658	18,995	41,526	124,134
150	513	984	2,054	6,043	17,255	37,744	112,911
175	472	905	1,890	5,566	15,905	34,809	104,199
200	438	841	1,758	5,182	14,819	32,447	97,184
300	350	673	1,411	4,167	11,943	26,190	78,585
400	298	574	1,205	3,567	10,239	22,477	67,539
500	263	508	1,066	3,160	9,082	19,955	60,025
1000	178	344	726	2,162	6,240	13,748	41,506
1500	141	274	578	1,727	4,999	11,035	33,388
2000	120	232	492	1,472	4,268	9,432	28,587

Pipe Capacities - Downstream of Meter

Flow in CFH for various lengths, sizes, and piping material

Based on 0.60 S.G. & 95% efficiency factor to account for equiv. length of pipe for fittings

P1 = 5.0 psig

P2 = 1.5 psig

Delta P = 3.5 psig

	Plastic (roughness = 0.000060)						
	1/2"	3/4"	1-1/4"	2"	3"	4"	6"
Length (ft)	**CTS**	**IPS**	**IPS**	**IPS**	**IPS**	**IPS**	**IPS**
20	986	5,939	17,860	49,679	141,390	274,570	757,277
40	669	4,056	12,234	34,121	97,357	189,351	523,411
60	522	3,241	9,794	27,358	78,177	152,184	421,225
80	453	2,762	8,360	23,378	66,874	130,265	360,892
100	399	2,440	7,391	20,688	59,230	115,431	320,027
125	352	2,154	6,534	18,303	52,447	102,263	283,725
150	317	1,946	5,906	16,558	47,478	92,612	257,102
175	291	1,785	5,422	15,211	43,641	85,157	236,524
200	269	1,656	5,035	14,132	40,565	79,180	220,017
300	214	1,319	4,018	11,296	32,477	63,451	176,546
400	181	1,122	3,422	9,632	27,725	54,203	150,959
500	159	989	3,020	8,510	24,518	47,958	133,665
1000	107	667	2,046	5,785	16,713	32,747	91,487
1500	84	530	1,628	4,611	13,345	26,175	73,230
2000	71	449	1,383	3,924	11,371	22,320	62,509

Steel (roughness = 0.00180)

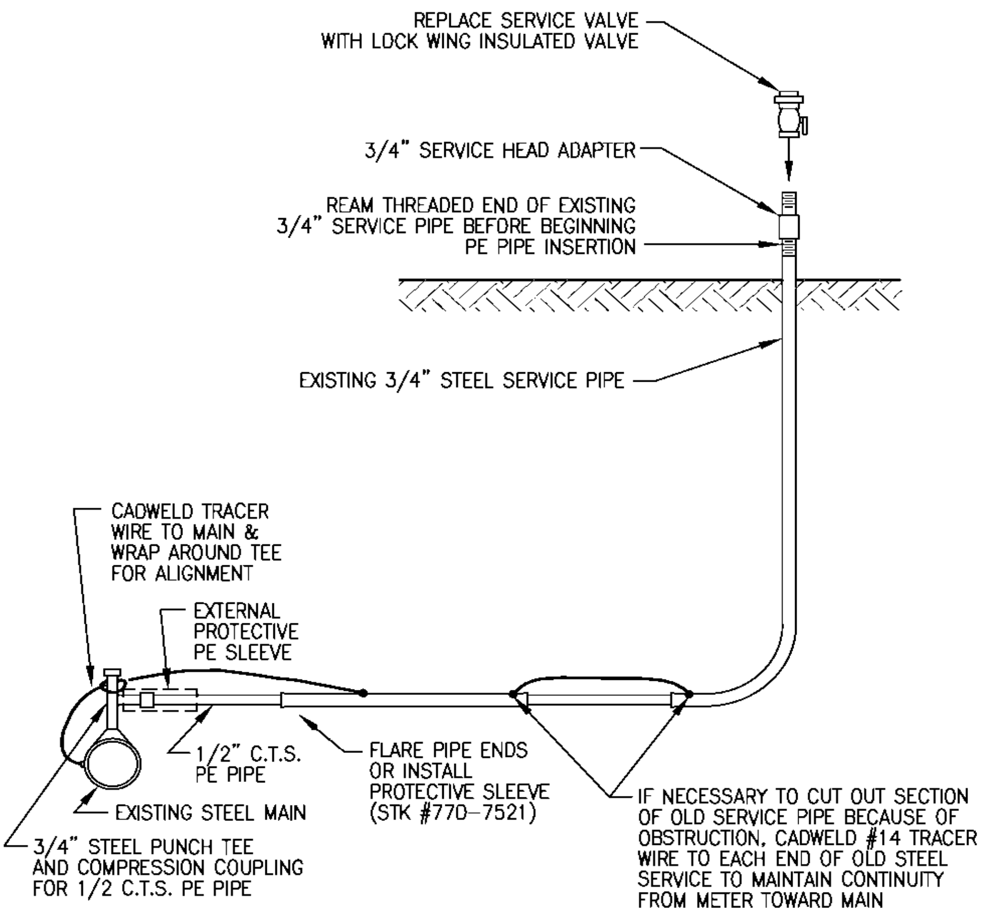
Length (ft)	3/4" Std.	1" Std.	1-1/4" Std.	2" Std.	3" Std.	4" Sch. 10	6" Sch. 10
20	4,341	8,225	16,968	49,157	138,612	300,765	891,068
40	3,040	5,767	11,911	34,558	97,559	211,840	628,129
60	2,465	4,680	9,674	28,096	79,382	172,460	511,673
80	2,123	4,032	8,341	24,247	68,552	148,994	442,269
100	1,889	3,591	7,433	21,621	61,164	132,985	394,916
125	1,681	3,197	6,621	19,275	54,560	118,672	352,574
150	1,527	2,907	6,023	17,544	49,687	108,111	321,326
175	1,408	2,681	5,558	16,200	45,902	99,906	297,047
200	1,312	2,499	5,184	15,117	42,853	93,294	277,481
300	1,058	2,018	4,191	12,243	34,757	75,738	225,511
400	907	1,732	3,601	10,535	29,939	65,286	194,559
500	805	1,538	3,200	9,371	26,656	58,162	173,455
1000	553	1,059	2,210	6,497	18,539	40,535	121,193
1500	443	850	1,776	5,233	14,964	32,763	98,120
2000	378	726	1,519	4,484	12,843	28,147	84,406

Pipe Capacities - Downstream of Meter
Flow in CFH for various lengths, sizes, and piping material
Based on 0.60 S.G. and 95 percent efficiency factor to account for equivalent length of pipe for fittings

P1 = 7.0" W.C.
P2 = 6.5" W.C.
Delta P = 0.5" W.C.

	Plastic (roughness = 0.000060)						
	1/2"	3/4"	1-1/4"	2"	3"	4"	6"
Length (ft)	CTS	IPS	IPS	IPS	IPS	IPS	IPS
20	51	276	856	2,438	7,093	13,950	39,200
40	38	185	575	1,645	4,805	9,471	26,680
60	25	146	455	1,306	3,822	7,543	21,290
80	19	123	385	1,108	3,247	6,416	18,130
100	15	114	339	975	2,861	5,657	16,000
125	12	105	297	857	2,521	4,987	14,120
150	10	100	267	772	2,272	4,499	12,750
175	9	95	244	706	2,081	4,122	11,690
200	8	91	226	654	1,928	3,822	10,850
300	5	74	178	517	1,529	3,035	8,632
400	4	56	165	437	1,296	2,576	7,337
500	3	45	154	384	1,140	2,267	6,466
1000	2	22	115	257	763	1,523	4,361
1500	1	15	78	230	603	1,205	3,460
2000	1	11	59	210	509	1,020	2,934

	Steel (roughness = 0.00180)						
	3/4"	1"	1-1/4"	2"	3"	4"	6"
Length (ft)	**Std.**	**Std.**	**Std.**	**Std.**	**Std.**	**Sch. 10**	**Sch. 10**
20	236	455	956	2,837	8,163	16,840	44,940
40	159	308	650	1,938	5,601	11,580	34,480
60	126	245	517	1,548	4,484	9,290	27,720
80	107	207	439	1,318	3,826	7,936	23,720
100	104	182	387	1,163	3,382	7,020	21,010
125	98	160	341	1,026	2,987	6,208	18,600
150	92	144	307	925	2,698	5,612	16,830
175	87	133	281	848	2,476	5,152	15,470
200	82	131	260	786	2,297	4,784	14,370
300	63	188	206	624	1,829	3,815	11,490
400	47	106	182	529	1,554	3,247	9,799
500	38	95	173	465	1,369	2,864	8,655
1000	19	49	134	311	921	1,934	5,872
1500	13	33	99	286	730	1,534	4,673
2000	10	25	70	243	618	1,301	3,970



DISTRIBUTION - GAS
STANDARD
INSERTING 3/4" STEEL SERVICE PIPE
WITH 1/2" PE PLASTIC

AVISTA CORP
SPOKANE, WASHINGTON

NO	DATE	REVISION	BY	CKD
5	12-4-13	CORRECTED TO DATE	SLG	SRS
4	11-08	CORRECTED TO DATE	DLD	
3	06-00	REVISED TRACER WIRE CONNECTION	CJ	CKD
2	1-97	CORRECTED TO DATE	JW	
1	12-95	REVERSED INSULATED VALVE	RP	MF

SCALE	DATE	APPROVED
NONE	11-17-95	10-18-95

DSN FAULKENBERRY CKD
DR PICKUP NTD
CKD NTD JW
SHT 1 OF 1
A-34735

12/4/2013 9:55 AM

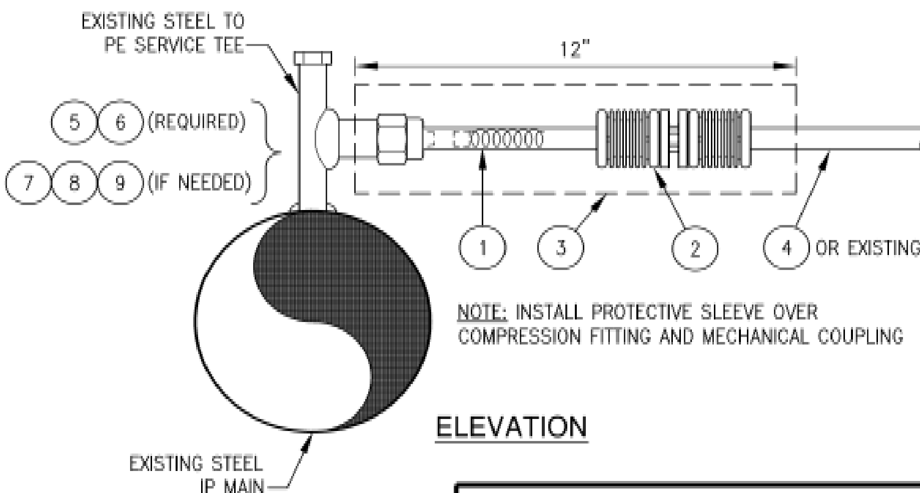
AUTOCAD DWG

MATERIAL LIST

ITEM	½" STOCK NO	¾" STOCK NO	QTY	DECRIPTION
1	771-8300	771-8302	1	EXCESS FLOW VALVE, 775 CFH
2	771-7535	770-5740	1	COUPLING, MECHANICAL
3	578-0264	578-0264	1	2" CONDUIT, PVC GAS SLEEVE, SCH 40, YELLOW
4	770-6340	770-6342	AS REQ'D	PIPE, PE, BI-MODAL
5	770-5550	770-5555	1	O-RING, FOR CONTINENTAL SERVICE TEE
6	770-5560	770-5565	1	SEAL RING, FOR CONTINENTAL SERVICE TEE
7	770-5570	770-5571	IF NEEDED	STEEL PLUG CAP, FOR CONTINENTAL SERVICE TEE
8	770-5580	770-5585	IF NEEDED	STIFFENER, FOR CONTINENTAL SERVICE TEE
9	770-5540	770-5545	IF NEEDED	COMPRESSION NUT, FOR CONTINENTAL SERVICE TEE

CONSTRUCTION NOTES

1	CONSTRUCT AND INSTALL PER COMPANY STANDARDS
2	THIS ASSEMBLY TO BE INSTALLED WHEN RETROFITTING AN EXISTING PE SERVICE FROM A STEEL MAIN, OR INSTALLING A NEW PE SERVICE FROM AN EXISTING STEEL TO PE SERVICE TEE
3	INSTALL EFV AND COUPLING IF APPLICABLE
4	INSTALL YELLOW PVC SLEEVE OVER COMPRESSION FITTING ON SERVICE TEE OUTLET AND MECHANICAL COUPLING
5	REPLACE SERVICE TEE O-RING AND SEAL RING
6	REPLACE SERVICE TEE CAP, STIFFENER, AND COMPRESSION NUT IF NEEDED



ELEVATION

DISTRIBUTION - GAS
STANDARD
UNIT ASSEMBLY
½" & ¾" PE SERVICE AND EFV OFF OF A STEEL IP MAIN
AVISTA CORP
SPOKANE, WASHINGTON

NO	DATE	REVISION	BY	CKD
3	8-24-22	UPDATE EFV STOCK NO	TJH	DRS
2	8-3-17	STANDARDS UPDATE	SJM	DRS
1	8-26-15	STANDARDS UPDATE	CGD	DRS
0	8-12-11	ISSUED FOR STANDARDS	TJH	QQU

SCALE 3" = 1'-0" DATE 07-19-11
DSN J. WEBB CKD QQU
DR TJH NTD
CKD DRS NTD CL
APPROVED David Howell
DATE 08-12-11
SHT 1 OF 1 A-37169

AUTOCAD DWG

3.17 PURGING PIPELINES

SCOPE:

To establish uniform procedures for the purging of air or natural gas from distribution and transmission facilities.

REGULATORY REQUIREMENTS:
§192.629, §192.751

CORRESPONDING STANDARDS:

Spec. 3.12, Pipe Installation - Steel
Spec. 3.13, Pipe Installation - Plastic
Spec. 3.32, Repair for Steel Pipe
Spec. 3.33, Repair for Plastic Pipe
Spec. 3.34, Squeeze-Off PE Pipe and Prevention of Static Electricity

Prevention of Accidental Ignition

It is essential that vented natural gas and air/gas mixtures be diffused into the air without hazard to Company personnel, the general public, or property. Each potential source of ignition must be removed from the area and a fire extinguisher must be provided. In addition to the precautions discussed in this specification, those who work on or near gas pipeline facilities shall be aware of the risks of their activities. In all situations, trained individuals shall be able to identify risks in their immediate area including sources of ignition that may not be obvious. Some factors to consider:

- Cars, trucks, and engine-driven construction equipment: Where are vehicles in relation to a potential gas envelope? Remain upwind of the gas facilities whenever possible.

- Warning Signs: Are passing motorists and pedestrians aware of the presence of gas facilities? Ensure appropriate signage is in place and that it provides sufficient information to warn of the risks of gas-fueled fires. Such warning signs include not only those that are permanently affixed at Gate Stations and Regulator Stations but also temporary signage that may be placed any time the public should be informed of a temporary gas ignition risk in an area.

- Sparks from hand tools: Are precautions being taken when accessing vaults and manhole covers? Avoid glancing blows on metal, concrete, and stone to prevent sparks.

- Sparks from electrical switches, telephones, and flashlights: Do not ring doorbells, operate thermostats, telephones, or light switches when in a potentially explosive environment. Do not use flashlights unless they are of the explosion-proof variety.

- Traffic signals: Are Street lighting and signal control boxes nearby? If possible, request that the appropriate agency temporarily disconnect these devices during a blowing-gas event.

- Welding equipment: Do not permit the use or storage of welding equipment where a dangerous gas-air mixture may exist. Prior to welding, cutting, or other hot work in or around a structure or area including a trench containing gas facilities, a thorough check shall be made with a combustible gas indicator (CGI) for the absence of a combustible gas mixture. CGI readings shall continuously be taken while repairs are being made until the area is made safe.

PURGING REQUIREMENTS:

General

Purging of air or natural gas prevents a combustible mixture of gas and air from occurring in the pipeline.

Purging is required:
- When new facilities are brought into service.
- Post blowdown when existing facilities are brought back into service.
- Post blowdown when existing facilities are temporarily taken out of service and the removal of natural gas is necessary.
- Post blowdown when lines are to be abandoned.

Purging Plan

When necessary, a written plan for purging should be prepared prior to the work and reviewed with the Company personnel involved.

The following items should be discussed:
- The extent of the facility to be purged and points of isolation.
- The purging medium to be used.
- Safe working practices, especially around plastic pipe due to concerns of static charges that may develop. Refer to Specification 3.34, Squeeze-Off of P.E. Pipe and Prevention of Static Electricity.
- Means of communication during purge.
- Means of determining when purge is complete.
- Procedures for handling emergencies, such as gas ignition.
- Notification of local agencies if required (police, fire, air pollution, noise abatement).
- Backup provision, in case of unanticipated occurrences (i.e., compressor failure, insufficient supply of purging gas, etc.).

Purging Main with Laterals

When purging a pipeline which has laterals or branches, care must be taken to remove the air or gas from all sections of the piping system. The main (trunk) section should be purged first, then each lateral.

Injection Rate

Injection of purging medium must be done at a high velocity (100 lineal feet per minute minimum) within the pipeline. A high flow rate will maintain a turbulent interface between the natural gas and air to minimize the mixing of the gas and air in the pipeline.

A purging rate of 100 feet per minute is easily maintained within a pipeline by partially opening a main line valve in all but low pressure systems. The vent stack should be smaller than the piping being purged, where possible. Sizing the vent stack smaller than the pipe helps ensure that the discharge velocity is greater than the flashback velocity, so accidental ignition from outside cannot travel back into the piping.

Venting and Blow Down

A permanent or temporary steel vent stack shall be used that is valved and in the vertical position. It should be of a safe height to keep the natural gas out of the work area and to blow it in a safe direction. The vent pipe shall be grounded using a 12-inch minimum grounding rod. Buildings, overhead lines, aircraft landing patterns, and other obstructions or sources of ignition should be considered when determining the location for venting the gas. Plastic pipe shall not be used as a vent stack as electrical charges on the pipe can cause ignition. An anodeless riser, however, may be used as a vent stack so long as an effective grounding device can and does get installed.

Blow Down Procedure:

Assure a safe work area that prevents the general public, non-essential personnel, and equipment from entering. Access shall be restricted only to personnel required to be within the work area. All other individuals and equipment should be kept a safe distance away. If possible, place no smoking / warning signs, barricades, and yellow plastic warning tape as necessary to assist.

Employ appropriate PPE and safety equipment as required by existing field conditions per Section 4 of the GESH and Part 7, Section 7.5 of the Avista Incident Prevention Manual (Safety Handbook) prior to entering the work area.

Survey the existing field conditions to understand the potential hazards to venting gas at a specific location. Take the necessary precautions to allow the discharge of gas to the atmosphere without hazard. Non-required personnel should be moved to a safe distance from the blow down stack.

On permanent blow down facilities that utilize closure devices or blind flanges on the outlet of the blow down stack, bleed off any pressure that might exist between the operating valve and this fitting prior to removal of the fitting.

Begin the blow down operation by operating the vent stack valve to allow a controlled release of gas from the blow down stack to atmosphere. It is important to monitor the pressure in the line you are intending to blow down and verify the pressure is dropping, indicating that the line is isolated from the system.

Continue to survey the immediate area for changes to existing field conditions and follow strict precautions to prevent accidental ignition of venting gas and to ensure the safety of Company personnel, the general public, and/or property during blow down.

Follow the purging requirements further outlined in this specification. Purging, once started, must be continued until completed so as not to allow combustible mixtures of gas and air to develop.

When possible, consideration must be given to the public with regard to noise and odor as well as to any applicable state and local noise and pollution abatement requirements. Such considerations may include the notification of residents in close proximity to the blow down operations, the use of noise suppressers, reduction of line pressure, reduced rate of venting, etc. Gas Control should be notified prior to the purging procedure so they can react to calls from the public and dispatch crews as necessary.

Static Charges

Polyethylene is a poor conductor of electricity; therefore, precautions must be taken to prevent build-up of static electrical charges on plastic pipe during purging operations. Refer to Specification 3.34, Squeeze-off of PE Pipe and Prevention of Static Electricity.

Bleed Off of Steel Pipe

When bleeding off pressure in steel pipelines that have been stopped-off or valved-off, a steel-valved vent stack shall be installed to bleed-off the pressure remaining in the pipeline prior to cutting the pipe. Refer to "Venting and Blow Down" in this Specification. If the system does not bleed down, shut valve to vent stack and check fittings used to stop the flow. A bonding cable shall be connected across the proposed opening before cutting a steel pipe apart. The cable will carry the electrical current and prevent sparking.

Bleed Off of Plastic Pipe

When bleeding-off pressure in plastic pipelines that have been squeezed-off or valved-off, a steel-valved vent stack (service tee connected to a riser with a valve) shall be installed to bleed off the pressure remaining in the pipeline prior to cutting the pipe**. Do not purge through the squeezers without installing these additional fittings to control the flow and direction of the bleed-off gas.** Refer to "Venting and Blow Down" in this specification. If the system does not bleed down, shut valve to vent stack and check fittings used to stop the flow.

On small diameter pipe (1/2 inch and 3/4 inch) there may not be the ability to install a steel-valved vent stack due to unavailability of fittings to connect to the pipe before making a cut in the pipe. On short sections of pipe in all diameters (for example stubs and transition fittings) there may not be enough clearance to squeeze and install a steel-valved vent stack before making the cut in the pipe. In these cases, the pipe shall be squeezed or shutoff in a location that minimizes the amount of gas to be bled off. For pipe larger than 3/4 inch diameter, the length of pipe being bled off shall not exceed 5 feet without the use of a steel-valved vent stack.

PURGING AIR OUT OF FACILITIES TO BE PLACED IN SERVICE:

NOTE: For any diameter of pipe, it is important to monitor the pressure during the purging process. At no time can the pressure exceed the MAOP. If at any time the pressure exceeds the MAOP plus the allowable build-up, contact Gas Engineering.

Purging Services

Service installations may be purged by opening the riser valve after the service tee been tapped. Care must be taken to blow gas away from structures by connecting a meter bend or street elbow to the riser valve and pointing the stream of gas in a safe direction. The valve should be opened slowly to the fully open position; no person or object should be in the exhaust stream area. The operator shall hold the wrench and keep it in contact with the valve stem at all times. Care must be taken to be aware of all potential ignition sources and direct the purge in a safe direction. See Sheet 1 of this specification for further guidance on "Prevention of Accidental Ignition." A sufficient amount of gas should be blown to atmosphere and a combustible gas indicator used to ensure that all air is removed from the line. Service lines should be purged immediately after the service tee has been tapped and gas is in the service line.

Purging Services with an Excess Flow Valve

As an Excess Flow Valve (EFV) is designed to shut off excess flow, purging of a service with an EFV must be done with care. The purging procedure is outlined in Specification 3.16, Services, "Installation of Excess Flow Valve."

Small Pipelines

Purging of Pipelines 6 inches in Diameter and Smaller.

Small diameter mains should be purged of air by injecting gas at high enough velocities to create a minimum lineal flow of 100 feet per minute within the pipeline (refer to "Injection Rate" above). A slug of nitrogen between the air and gas is required if this velocity cannot be met. It may also be beneficial to use nitrogen for long pipeline purges.

Small diameter plastic gas mains shall be purged by controlling the flow rate with a valve on the vent stack or riser. The vent stack or riser shall be located no further than 5 feet from the end of the pipe being put into service. Avoid squeezing near the venting end as this is the area of concern for static buildup.

Large Pipelines

Purging Pipelines Larger than 6 inches in Diameter.

For mains greater than 6 inches diameter, it is desirable to separate the air from the natural gas with a slug of nitrogen. This technique minimizes mixing which otherwise would be accelerated due to the greater cross-sectional area of the large diameter pipe and reduces required purge time.

When the use of nitrogen is impractical, pipelines with a diameter greater than 6 inches are purged of air by injecting natural gas into the line at high velocities. Mixing of air and gas is more of a problem for larger diameters and the purge will usually take longer.

Purging with Nitrogen

To prevent explosive mixtures when purging long, large diameter lines, a slug of nitrogen can be injected into the line prior to the purging medium. The nitrogen will mix with the air and the gas, but as long as sufficient nitrogen is injected, an explosive mixture will not occur. The following table gives the required volumes of nitrogen for various pipeline diameters and lengths.

NITROGEN PURGING DATA FOR 4" - 20" PIPE
VOLUME OF NITROGEN REQUIRED FOR INERT SLUG FOR VARIOUS PIPE SIZES
AT 100 FT./MIN. MINIMUM INJECTION RATE

Pipe Diameter	Pipe Content Cu. Ft./ Ft.	Cu. Ft. Nitrogen Per Length of Pipe						
		500'	1,000'	2,000'	5000'	10,000'	20,000'	50,000'
4"	0.09	10	10	20	20	20	30	40
6"	0.22	30	30	30	40	50	70	100
8"	0.37	70	70	80	90	120	160	200
10"	0.58	130	140	150	180	230	280	350
12"	0.83	280	300	340	370	400	430	470
16"	1.3	580	630	700	790	850	910	1,000
18"	1.67	740	850	970	1,100	1,200	1,300	1,400
20"	2.08	1,100	1,200	1,400	1,600	1,700	1,800	2,000

This table is based on providing a slug which will reduce to about 100 feet in length at end of purge. To provide an additional safety factor, some operators use double the amount of nitrogen indicated.

NOTE: One cylinder of nitrogen at 2200 psig = 220 cubic feet at atmospheric pressure.
Information from Tables 8-4, "Purging Principles and Practice", AGA, Cat. No. XK0775, 1975.

Immediately following the introduction of the inert gas, natural gas shall be injected into the pipeline in a continuous and rapid manner and vented at the terminal end until the vented gas is free from air. Check for the presence of 93 percent gas or higher with a CGI.

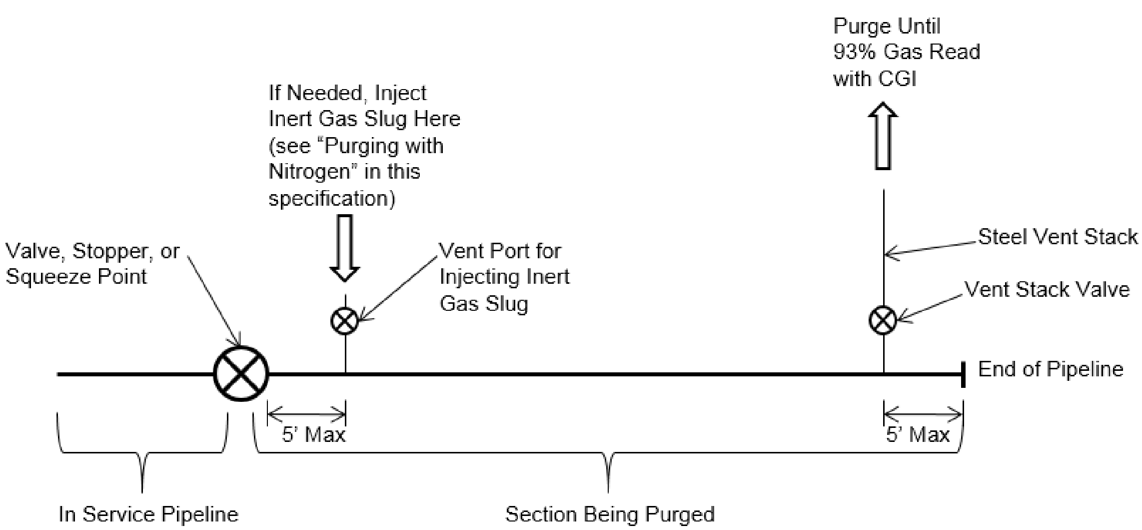
Once a continuous and pure flow of natural gas is obtained through the vent stack, the venting valve shall be closed. Pressure within the main shall be allowed to build up to the available gas pressure. Close the throttling (or control) valve, then the venting valve shall be opened, and the accumulated pressure allowed to dissipate. This procedure should be repeated a minimum of two times to ensure that any pockets of air were not bypassed in the pipeline due to a laminar flow condition.

Following completion of the above steps, the pipeline may be placed in service.

Following are additional facts regarding inert slug purging:

- Purge velocity is extremely important. Avoid a slow purge. Velocities less than 100 feet per minute in large diameter pipe allow stratification between heavier and lighter gases.
- The amount of nitrogen necessary to purge short lengths (500 feet or less) of large-diameter pipe satisfactorily at practical purge velocities exceeds the volume of the line.
- Changes in horizontal or vertical direction because of elbows or return bends do not destroy the nitrogen slug.
- A temperature variation in the order of 20 degrees F has no effect on mixing of the nitrogen slug with combustible gas or air.
- Turbulence, even if it causes mixing, is much less the cause of deterioration of the slug than is stratification, which is the process of layering.

The following illustration shows a guideline for purging a pipeline into service (replacing air with natural gas).



Verifying the Presence of Gas

The use of a combustible gas indicator (CGI) to check for 93 percent gas or higher is the method that should be used when purging air out of facilities to be placed into service.

PURGING NATURAL GAS OUT OF EXISTING FACILITIES:

NOTE: For any diameter of pipe, it is important to monitor the pressure during the purging process. At no time can the pressure exceed the MAOP. If at any time the pressure exceeds the MAOP plus the allowable build-up, contact Gas Engineering.

Small Pipelines

Purging of Pipelines 6-inches Diameter and Less:

Lines 6-inches in diameter and smaller are purged of natural gas using an air mover or by purging with air.

In cases such as services of Can't Gain Entry Cut-offs where both ends of the line are not accessible, gas may be purged out by "flushing" the line several times with nitrogen. This is accomplished by injecting nitrogen to a safe pressure level (at or below the MAOP) in the service, releasing it to atmospheric pressure and repeating as necessary.

The disposal of large volumes of natural gas into the atmosphere should be minimized as far as practical by transferring as much as possible to adjacent systems.

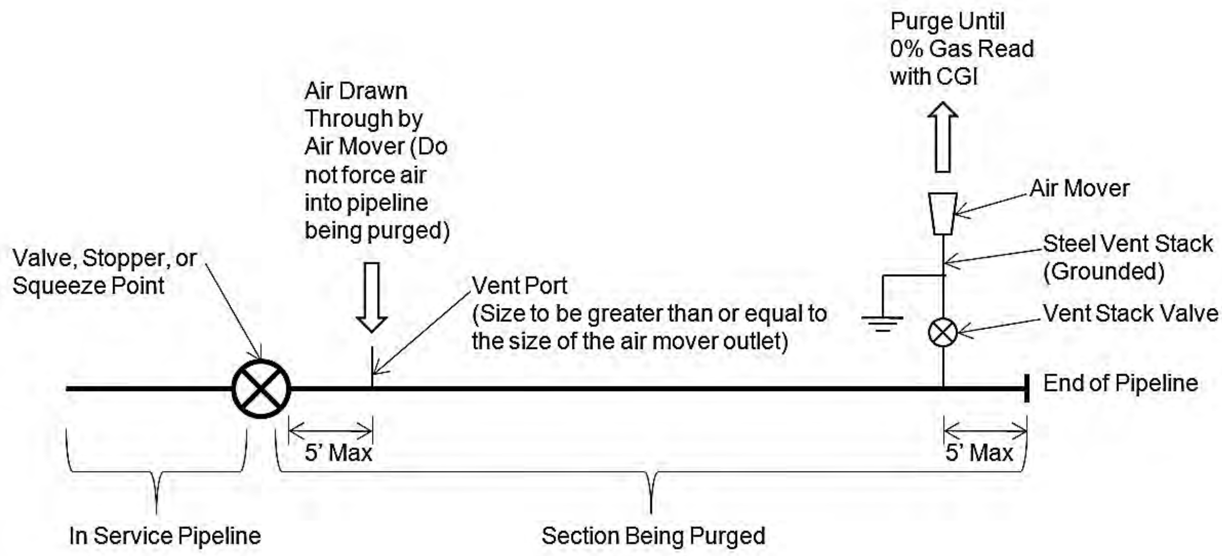
Large Pipelines

Purging of Pipelines Larger than 6-inches Diameter:

For mains greater than 6-inches diameter, it is desirable to separate the natural gas from the air with a slug of nitrogen as detailed in "Purging with Nitrogen" in this specification. This technique prevents mixing which otherwise would be accelerated due to the greater cross-sectional area of the large diameter pipe and reduces purge time.

When it is impractical to use nitrogen, pipelines with a diameter greater than 6 inches can be purged of natural gas with air. Except for short lengths, this should be performed with an air mover. Contact Gas Engineering for further guidance.

The following illustration shows a guideline for purging a pipeline out of service (replacing natural gas with air).



Verifying the Absence of Gas

A combustible gas indicator (CGI) should be used to verify the absence of combustible gas when purging gas from existing facilities or when working around structures that could contain or trap combustible gas. Structures to consider include but are not limited to existing pipelines, abandoned pipelines, casings, sewers, confined spaces, and vaults.

Flaring of Natural Gas

Occasionally, it is desirable to flare (ignite) gas during a purge to eliminate odor, ensure that uncontrolled combustion does not occur, and to reduce methane emissions to the atmosphere. Consideration should be given to the distraction this might create to the public in high visibility areas. If this procedure is to be used, refer to "Venting and Blow Down" in this specification.

Working on Purged Pipeline

When it is necessary to perform work on an existing pipeline which has been purged, precautions shall be taken to verify that a combustible mixture has not developed inside the pipeline due to leakage from a segment of pipeline remaining in service, or from the release of gas from residual liquids in the pipeline. Special care must be taken when performing cutting or welding on such a line. The degree of isolation should be determined by observing any pressure increases within the purged space with all vents closed and by monitoring for the presence of natural gas.

3.18 PRESSURE TESTING

SCOPE:

To provide a procedure that covers the requirements of pressure testing for new, replaced, or re-connected pipelines and facilities.

REGULATORY REQUIREMENTS:

§192.121, §192.143, §192.503, §192.505, §192.506, §192.507, §192.509, §192.511, §192.513, §192.515, §192.619, §192.620, §192.719, §192.725

WAC 480-93-170

OTHER REFERENCES:

ASTM A234 or A860 standards

CORRESPONDING STANDARDS:

Spec. 3.12, Pipe Installation—Steel
Spec. 3.13, Pipe Installation—Plastic
Spec. 3.17, Purging Pipelines
Spec. 3.32, Repair of Steel Pipe
Spec. 3.33, Repair of Plastic (Polyethylene) Pipe

PRESSURE TESTING REQUIREMENTS:

New and Replacement Pipe

New and replaced pipelines and facilities transporting natural gas must be tested and shall maintain a constant test pressure (excluding fluctuations because of temperature and sunlight) for durations in accordance with the tables in this specification.

Dry Line Pipe

"Dry line" pipe (pipe that is installed but not put into service immediately) shall be installed and tested according to the appropriate standard specifications. At the completion of successful pressure testing, the new dry system should be left with approximately 60 psig air remaining in the pipe. Mark the pressure as left on the pipe near the end of the pipe or logical future point of connection with a permanent marker. The presence of this pressure at the time the pipe is put into service will confirm there has been no damage during the time the system was idle. If pressure has been lost, the pipe is assumed to have sustained damage somewhere and any damaged portion must be repaired and then tested as if new before it is put into service. For further guidance on the installation of Dry Line Pipe, refer to Specification 3.12, Pipe Installation – Steel Mains, and Specification 3.13, Pipe Installation – Plastic (Polyethylene) Mains under the heading Dry Line Installations.

Pressure Testing for Steel

Following are general guidelines for pressure testing steel pipelines:

1. Maximum test pressure permitted, expressed as a percent of SMYS:

CLASS LOCATION	1	2	3	4
AIR OR INERT GAS	80	75	50	40
NATURAL GAS	80	30	30	30
WATER	100	100	100	100

2. Leak Tests / Safety: When testing a high-pressure steel installation (including regulator stations and farm taps) with air, inert gas, or natural gas, a leak test shall be performed at 100 psig before increasing to the ultimate required test pressure. This leak test shall be undertaken for the purpose of evaluating any above ground piping joints and fittings for leaks and is documented on the "High Pressure Leak Check Performed at _____ psig" line of the Pressure Test Information sticker. Appropriate safety precautions (limiting access, barricading, warning signs, etc.), depending on the test medium, shall be taken to protect employees involved in the test procedure as well as the general public.

3. Maximum test capabilities of fittings such as valves and elbows must be determined before testing.

4. The minimum test pressure shall not be less than 1.5 times the MAOP. The only exception is for pipelines where testing to 1.5 times the design pressure creates problems due to limitations imposed by valves or fittings (refer to Note 3). Contact Gas Engineering should this condition occur.

5. Pipelines 6-inches in diameter and larger which are designed to operate at more than 40 percent SMYS are to be tested to a minimum of 90 percent SMYS and as close to 100 percent SMYS as practical (tests of ERW pipe should be limited to a maximum of 95 percent SMYS). This will permit them to continue to operate at an established MAOP should a class location change occur. However, a test to 90 percent of SMYS is not to be used as an alternative to designing a pipeline to meet a higher class location which may reasonably be anticipated to occur in the future. Refer to Note 6 for additional information regarding large-diameter pipe testing procedures.

   Pre-Installation Tests: For short sections of pipe for which a post installation test is impractical, such as a section replacement or repair, a pre-installation pressure test may be substituted. A short section of pipe must contain only a single piece of pipe with no girth welds (steel) or fusion joints (PE). The pre-installation test must comply with the pressure requirements and durations for a post installation test and shall be documented on a Pre-Tested Pipe form (N-2743). The form is to be kept with the as-built job construction documents.

   For pre-tested steel pipe, as long as the material has been stored and managed as described in Specification 3.12, Pipe Installation –Steel, and there is no evidence of corrosion or damage to the materials following a successful pressure test, there is no limit to the life of the pressure test and the materials may be considered of reasonable integrity for use. Refer to Specification 3.32, Repair of Steel Pipe, "Pre-tested Steel Pipe" for recordkeeping requirements for pre-tested steel pipe.

If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required if the manufacturer of the component certifies that any of the following are true (however a soap test of the tie in weld/connection shall be performed at no less than the operating pressure of the system):

a. The component was tested by the manufacturer to at least the maximum allowable operating pressure of the pipeline to which it is being added;
b. The component is manufactured under a quality control system that ensures each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the maximum allowable operating pressure of the pipeline to which it is being added (carbon steel fittings and components other than pipe that meet ASTM A105 or ASTM A234, e.g. steel weld caps or threaded fittings); or
c. The component has a pressure rating per an ASME/ANSI classification, MSS specifications, or by strength calculations described in §192.143.
d. Note: Butt weld steel caps with a specification greater than Grade B do not meet any of the above criteria and do require a pressure test.

If a single component is replaced or added with no strength test, the soap test should be documented using "SOAP" as the test medium and showing the date and time the test is performed as well as who performed the test. This should be documented on the job card or yellow pressure test sticker.

6. Full encirclement pressure control type fittings, once welded to large diameter mains, may be leak tested to 100 psig for 20 minutes against a test cap. This may be performed to assure a leak tight weld prior to tying in the pressure control fitting to the remainder of the piping which shall be tested normally in a separate pressure test as required by this specification. This variance from normal testing procedures may be invoked by recommendation of Gas Engineering when the carrier pipe to which the fitting is being welded is of a large enough diameter (generally larger than 8 inches) at a test pressure that might cause deformity of the carrier pipe.

7. Testing of replacement pipe: If a segment of pipeline is repaired by cutting out the damaged portion, the replacement pipe section must be tested to the pressures required for a new line installation.

8. Testing instrument pipelines: Instrument pipelines made of steel pipe and subjected directly to mainline gas pressures shall be tested in accordance with the applicable test requirements in the above table. It is not necessary to test tubing, but all fittings and connections should be checked for leaks.

9. Tests to over 50 percent SMYS should be performed with water as the test medium, unless such a test is impractical. Where a hydrostatic test is impractical, air or inert gas may be used, with the limitations shown in Note 1. Buildings within 300 feet of the test section must be evacuated during the test if air or inert gas is used as the test medium.

10. Without prior approval from Gas Engineering, testing using water, air, or inert gas is not permitted where the test section is isolated from an operating pipeline only by a closed valve, squeeze off equipment, or plugging equipment, since leakage may occur creating an undesirable and potentially hazardous situation.

11. Where pipelines are installed on street or highway bridges under permits from governmental agencies, more stringent testing may be required by the agency than would be required by this gas standard.

12. Pipe for which hydrostatic testing is used shall be pigged to remove all water from within the pipe. It may be necessary to utilize additional means of drying the pipe such as pigging with methanol or introduction of a medium such as nitrogen or desiccated air into the pipeline. Refer to Specification 3.12, Pigging of Pipe, for more information. Contact Gas Engineering for assistance.

13. Care should be taken to address environmental concerns and regulations with respect to the disposal of the test medium.

Notification to Washington UTC Prior to Pressure Testing Transmission Pipelines

WAC 480-93-170(1): In the state of Washington, the commission must be notified in writing at least 3 business days prior to the commencement of any pressure test of a gas pipeline that will have an MAOP that produces a hoop stress of 20 percent or more of the SMYS of the pipe used. Pressure test procedures must be on file with the commission or submitted at the time of notification.

a) Pressure tests of any such gas pipeline built in Class 3 or Class 4 locations, or within 100 yards of a building, must be at least 8 hours in duration.
b) When the test medium is a gas or compressible fluid, the operator must notify the appropriate public officials so that adequate public protection can be provided for during the test.
c) In an emergency situation where it is necessary to maintain continuity of service, the requirements of subsection (1) of this section and subsection (1)(a) of this section may be waived by notifying the commission by calling the emergency notification line (1-888-321-9144) prior to performing the test.

PRESSURE TESTING REQUIREMENTS – HIGH PRESSURE STEEL PIPELINE SYSTEMS[1]

DESCRIPTION	PIPE SIZES (in)	TEST PRESSURE (MINIMUM) IN PSIG	TEST MEDIUM[3]	LENGTH OF MAIN (ft.)	DURATION OF TEST (MINIMUM) (Hours)	TYPE OF GAUGE	REMARKS
High Pressure: Gas Mains, Services [2], Regulator Stations, Farm Taps, and Meter Set Assemblies	≤ 2	As Specified by Gas Engineering	Air, Natural Gas, Inert Gas, Water[3]	0-500	1	Recording Chart	Soap test joints of above grade or exposed pipe and fittings during the test.
	> 2	As Specified by Gas Engineering	Air, Natural Gas, Inert Gas, Water[3]	0-500	4	Recording Chart	
	All	As Specified by Gas Engineering	Air, Natural Gas, Inert Gas, Water[3]	501-2,000	8	Recording Chart	
	All	As Specified by Gas Engineering	Air, Natural Gas, Inert Gas, Water[3]	Over 2,000	24	Recording Chart	
High Pressure: Cans, Barrels & Prefabricated Welded Assemblies or Units[5]	All	As Specified by Gas Engineering	Air, Natural Gas, Inert Gas, Water[3]	N/A	1	Recording Chart	To operate at < 30 percent SMYS
	All	As Specified by Gas Engineering	Air, Natural Gas, Inert Gas, Water[3]	N/A	4	Recording Chart	To operate at ≥ 30 percent SMYS
Tie-in Joints (all pressures)	All	Current Operating Pressure	Soap Test[4]	N/A	N/A	N/A	

[1] For installations less than 20 percent SMYS. Refer to WAC 480-93-170(1) for installations with an MAOP that produces a hoop stress of 20 percent or more of SMYS. Refer to 192.505 for installations with an MAOP that produces a hoop stress of 30 percent or more of SMYS.

[2] Pressure tests of services includes service pipe and service riser. (Does not include customer meter.)

[3] If water is the test medium, then the test must run for at least 24 hours to allow the pipe and water temperatures to stabilize.

[4] When soap testing, the entire joint shall be visually checked to ensure there are no leaks. Use a mirror or other means, if necessary, to inspect the entire joint.

[5] See the section on Pressure Vessels and Prefabricated Units in Specification 2.12 for more information

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PRESSURE TESTING REQUIREMENTS – INTERMEDIATE PRESSURE STEEL PIPELINE SYSTEMS

DESCRIPTION	PIPE SIZES	TEST PRESSURE (MINIMUM) IN PSIG	TEST MEDIUM	LENGTH OF MAIN (Ft)	DURATION OF TEST (Min)	TYPE OF GAUGE	REMARKS
Intermediate Pressure Gas Mains	All	90	Air, Natural Gas, or Inert Gas	0-10	10 Min	Gauge[4]	It is recommended to soap test joints of above grade or exposed pipe and fittings during the test to check for leaks.
	All	90	Air, Natural Gas, or Inert Gas	11-1000	1 Hr.	Gauge[4]	
	All	90	Air, Natural Gas, or Inert Gas	1001-10,000	1 Hr. per 1000 Ft.[1]	Gauge[4]	
	All	90	Air, Natural Gas, or Inert Gas	Over 10,000	24 Hrs.	Recording Chart	
Intermediate Pressure Gas Services[2]	All	90	Air, Natural Gas, or Inert Gas	0-200	10 Min.	Gauge[4]	
	All	90	Air, Natural Gas, or Inert Gas	201- 1000	1 Hr.	Gauge[4]	
	All	90	Air, Natural Gas, or Inert Gas	Over 1000	1 Hr. per 1000 Ft.[1]	Gauge[4]	
Intermediate Pressure: Cans, Barrels & Prefabricated Welded Assemblies or Units[6]	All	90	Air, Natural Gas, or Inert Gas	N/A	15 Min.	Gauge[4]	
Intermediate Pressure Industrial Meter Set Assemblies	All	90	Air, Natural Gas, or Inert Gas	N/A	1 Hr.	Gauge[4]	
Tie-in Joints (all pressures)	All	Current Operating Pressure	Soap Test[3]	N/A	N/A	N/A	

[1] Round up to the next full hour

[2] Pressure tests of services includes service pipe and service riser. (Does not include customer meter.)

[3] When soap testing, the entire joint shall be visually checked to ensure there are no leaks. Use a mirror or other means, if necessary, to inspect the entire joint.

[4] If an analog gauge is used, the gauge shall have a range of 0-150 psi with 1 psi divisions (maximum) and an accuracy of ±0.25 percent of full scale (maximum). If a digital gauge is used, the gauge shall meet or exceed the resolution and accuracy of the analog gauge specified above.

[5] If a pressure test combines both main and service, the total length of main plus the service shall be considered as main (i.e., 800 ft of main plus 600 ft of service tested together shall be tested as 1,400 feet of main)

[6] See Prefabricated Unit and Pressure Vessel section in Specification 2.12 for more information.

Pressure Testing Requirements for PE

Following are general guidelines for pressure testing PE pipelines:

1. Maximum test capabilities of fittings such as valves and elbows must be determined before testing.

2. The minimum test pressure shall not be less than 90 psig.

3. The maximum test pressure for medium density polyethylene pipe shall not exceed 125 psig. Testing in excess of 120 psig should not exceed a duration of 48 hours. Contact Gas Engineering if your test will approach these criteria.

4. <u>Pre-installation Tests</u>: For short sections of pipe for which a post installation test is impractical, a pre-installation test may be substituted. The pre-installation test must comply with the pressure requirements for a post installation test and shall be documented on a Pre-Tested Pipe form (N-2743) and the form kept with the as-built job construction documents. The following definition shall apply:

   A **Short Section of Pipe** is defined as a single piece of pipe containing no girth welds (steel) or fusion joints (PE).

   If a component other than pipe is the only item being replaced or added to a pipeline, a strength test after installation is not required if the manufacturer of the component certifies that any of the following are true (however a soap test of the tie in connection shall be performed at no less than the operating pressure of the system):

   a. The component was tested by the manufacturer to at least the maximum allowable operating pressure of the pipeline to which it is being added;
   b. The component is manufactured under a quality control system that ensures each item manufactured is at least equal in strength to a prototype and that the prototype was tested to at least the maximum allowable operating pressure of the pipeline to which it is being added (PE fittings that meet ASTM D2513 standards, e.g., end caps); or
   c. The component has a pressure rating per an ASME/ANSI classification, MSS specifications, or by strength calculations described in §192.143.

   If a single component is replaced or added with no strength test, the soap test should be documented using "SOAP" as the test medium and showing the date and time the test is performed as well as who performed the test. This should be documented on the job card or yellow pressure test sticker.

5. Where feasible, plastic pipe must be installed and backfilled prior to pressure testing to expose any potential damage that could have occurred during the installation process. During the testing the pipe shall not be exposed to temperatures above 140 degrees F per the requirements of §192.121 and §192.513.

For pre-tested plastic pipe, as long as the pipe and fitting materials have not reached or exceeded their useful life per Specification 3.13, Pipe Installation – Plastic, and the pre-tested materials show no evidence of damage following a successful pressure test then there is no limit to the life of the pressure test and the materials may be considered of reasonable integrity for use (refer to Specification 3.33, Permanent Repair Sleeves, "Pre-tested PE Pipe" for recordkeeping requirements for pre-tested PE pipe).

PRESSURE TESTING REQUIREMENTS - PLASTIC PIPELINE SYSTEMS

DESCRIPTION	PIPE SIZES	OPERATING PIPELINE PRESSURE PSIG	TEST PRESSURE (MINIMUM)	TEST MEDIUM	LENGTH OF MAIN FEET	DURATION OF TEST (MINIMUM)	TYPE OF GAUGE	REMARKS
Intermediate Pressure Gas Mains	All	Up to 60	90	Air, Natural Gas, or Inert Gas	0-10	10 Min.	Gauge[4]	It is recommended to soap test joints of above grade or exposed pipe and fittings during the test to check for leaks.
	All	Up to 60	90	Air, Natural Gas, or Inert Gas	11-1000	1 Hr.	Gauge[4]	
	All	Up to 60	90	Air, Natural Gas, or Inert Gas	1001-10,000	1 Hr. per 1000 Ft.[1]	Gauge[4]	
	All	Up to 60	90	Air, Natural Gas, or Inert Gas	Over 10,000	24 Hrs.	Recording Chart	
Intermediate Pressure Gas Services[2]	All	Up to 60	90	Air, Natural Gas, or Inert Gas	0-200	10 Min.	Gauge[4]	
	All	Up to 60	90	Air, Natural Gas, or Inert Gas	201-1000	1 Hr.	Gauge[4]	
	All	Up to 60	90	Air, Natural Gas, or Inert Gas	Over 1000	1 Hr. per 1000 Ft.[1]	Gauge[4]	
Tie-in Joints	All	All	Current Operating Pressure	Soap Test[3]	N/A	N/A	N/A	

[1] Round up to the next full hour

[2] Pressure testing of services includes service pipe and service riser. (Does not include customer meter.)

[3] When soap testing, the entire joint shall be visually checked to ensure there are no leaks. Use a mirror or other means, if necessary, to inspect the entire joint

[4] If an analog gauge is used, the gauge shall have a range of 0-150 psi with 1 psi divisions (maximum) and an accuracy of ±0.25 percent of full scale (maximum). If a digital gauge is used, the gauge shall meet or exceed the resolution and accuracy of the analog gauge specified above.

[5] If a pressure test combines both main and service, the total length of main plus the service shall be considered as main (i.e., 800 ft of main plus 600 ft of service tested together shall be tested as 1,400 feet of main)

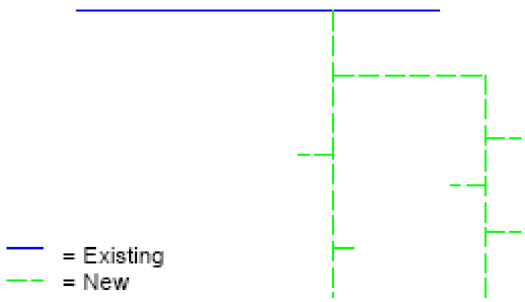
Reinstating Service Lines

A service line that has been broken, pulled, or damaged resulting in the interruption of gas supply to the customer shall be pressure tested from the break back to the meter location for the same duration and to the pressures required for a new service.

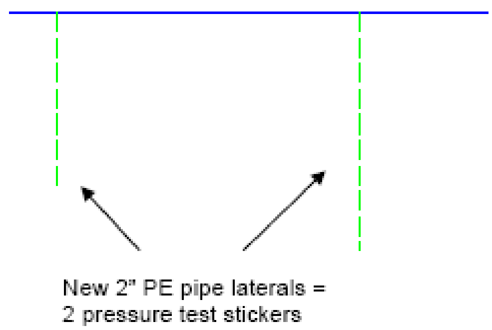
If damage is not the cause for service disconnection, then any part of the original service line that is disconnected (meaning any part of the service that was physically separated or detached from the system) must be tested in the same manner as a new service line from the point of disconnect to the meter valve with the exception of, any part of the original service line used to maintain pressure and continuous service to the customer need not be tested.

Recordkeeping

Pressure test information and/or charts must be completed and retained for the life of the facility. If only a spring gauge is required for a pressure test, consideration should be given to avoid complicating the project records by completing a pressure test chart as well.
Where multiple pressure tests are performed on a single installation, there shall be a record for each test. An example of this would be any continuous on-going job or installation such as a new plat or long main installed where more than one pressure test was conducted during construction.



Example of a single unit/assembly tested together.



Example of multiple facilities on same job.

Record the following information on the appropriate pressure test form, sticker, chart, or electronic service order / work order as applicable. (Note: The recording of the following data is required for both initial pressure tests of newly installed pipe and pressure tests for retested existing pipe after a damage / repair.)

- Operator's name
- Employee's name performing the test
- Test medium used
- Test pressure
- Test duration
- Date of test
- Time of day (use military time)
- Chart Box Setting (as applicable)
- Pipe diameter and footage for each diameter of pipe on a single test.
- Failed test information - If a pressure test fails, fill out the initial pressure information and mark the "test failed" box, then make repairs, re-pressure test and record the information on a new Pressure Test Information sticker (Form N-2490).
- Elevation variations, whenever significant (typically applicable for hydro testing)

Care must be utilized to ensure that the time period of the test agrees with the type of test chart being used.

Refer to Specification 3.33, Repair of Plastic Pipe, "Pre-Tested PE Pipe" for further information of recordkeeping requirements for pre-tested piping.

Below is an example of the Pressure Test Information sticker (Form N-2490) that should be filled out. These stickers can also be used on a pressure chart by placing sticker on back of chart (Ensure "Time of Day" is recorded in military time).

Only individuals who are Operator Qualified on Task 221.120.075, Pressure Testing Gas Pipelines, shall sign off on pressure testing charts and/or test stickers.

Furthermore, only the person actually performing the pressure test shall sign off on the applicable documentation.

AVISTA PRESSURE TEST INFORMATION

Test Medium Used ______________________
Pressure Tested To ____________________ PSIG
Gauge Number GPG-______________________
Time of Day Test Started ______________ (MilitaryTime)
For ______________ Hr. ______________ Min.
Diameter of Pipe ______ Footage ______________
Diameter of Pipe ______ Footage ______________
Diameter of Pipe ______ Footage ______________
Test Failed ☐ (repair, retest, record info on new form)
☐ High Pressure Leak Check Performed at ______ psig
The "As Constructed" information indicated on this print is correct. All construction complied with current Avista standards/ specifications

______________ ______________________
Date of Test Test Performed By (Print Name)
N-2490 (01-17)

PRESSURE TEST PROCEDURES:

1. Isolate the test segment by sealing any open ends such as with a fused cap, welded cap, or a blind flange, etc.

2. Connect the pressure testing equipment and assemblies to the line.

3. Pressurize the line to the test pressure minimum per the requirements of this specification. Test pressure should be slightly higher than the specified minimum to assure that the temperature changes during the test do not cause the test pressure to fall below the minimum allowed to establish the required design MAOP. If the line to be pressure tested is at a high-pressure facility, the test must be held at approximately 100 psig and a leak test performed of above ground pipe joints, and fittings prior to pressurizing the line to the ultimate test pressure.

4. Maintain the test for the duration as specified in the charts per this specification. For long segments of pipe, maintain the test long enough to be certain that the temperature of the test medium has stabilized.

5. It is recommended to soap test joints of above grade or exposed pipe and fittings during the test to check for leaks.

6. Compare the readings before and after the test. If there is no pressure drop during the test, the pipe has passed the pressure test.

7. If the pressure cannot be maintained, there is a leak that needs to be located and repaired. If a test fails, record the information from the test on the form, sticker, or chart and note that it has failed. Fluctuations in ambient temperature during the test may cause the pressure to either increase or decrease during the test. If a pressure fluctuation occurs and if it is suspected to be contributed to an ambient temperature change, consult Gas Engineering for further guidance before concluding the test. Ensure Gas Engineering documentation of the influence of temperature on a pressure test is stored with the job file.

8. Make repairs and then repeat the pressure test and record the new pressure test information on another pressure test form, sticker, or chart.

9. When the pressure test shows no sign of leakage, purge the line per company procedures, Specification 3.17, Purging of Pipelines, and tie in the pipe.

10. Record the test data as outlined in the Recordkeeping section of this specification on the appropriate pressure test form, sticker, or chart.

3.19 TRENCHLESS PIPE INSTALLATION METHODS

SCOPE:

To provide a procedure that covers trenchless pipe installation methods such as Horizontal Directional Drilling (HDD), Pipe Splitting and Pneumatic Missiling/Piercing.

REGULATORY REQUIREMENTS:

§192.303

CORRESPONDING STANDARDS:

Spec. 3.12, Pipe Installation – Steel
Spec. 3.13, Pipe Installation – Plastic
Spec. 3.15, Trenching and Backfill
Spec. 3.18, Pressure Testing

GENERAL:

Tracking and Potholing when Crossing Utilities

In order to help prevent a cross bore from occurring, existing underground utilities that cross a trenchless installation path (regardless of the angle of the crossing) must be verified using depth measurement, as-built records (i.e., sewer), potholing and/or exposing to protect the existing facilities prior to installation. Tracking the location and depth of the bore head should be utilized for directional boring installations. Reasonable means of tracking the location (and depth when possible) of the pneumatic missile are recommended for missile installations (for example using a metal detector, pipe locator, or feeling ground surface vibration).

Approved methods for verifying the location and depth of existing utilities within road right-of-way, public or private utility easement include:

1. Natural gas, petroleum, power, phone, cable TV and fiber optic lines believed to be within 24” of the full diameter of the proposed bore or ream hole (whichever is greater) shall be potholed to verify their exact location before crossing and these types of existing utilities shall be exposed within the proposed bore path. An additional 24” on the underside of the utility shall be exposed in the pothole if the proposed bore path is beneath the existing utility. This should allow adequate clearances to be visually verified. If these existing utilities are deeper than 24” below the full diameter of the proposed bore or ream hole (whichever is greater) then exposure of the utility may not be required as long as the pothole extends a minimum of 24” below the proposed bore or ream hole within the bore path and reasonable effort is made to verify the accuracy of the locate during potholing.
2. Existing gravity fed sanitary/storm sewer, pressurized sewer and water utilities that have structures (manholes, catch basins, inlets/outlets, valve boxes, clean-outs, etc.) that can be measured and verified to be more than 24” above or below the full diameter of the proposed bore or ream hole may not need to be potholed. If these existing utilities cannot be verified for depth in the area that the bored crossing will take place, then the existing utility shall be potholed per item.
3. Use additional information on sewer maps and as-built records, if available, in combination with items 1 and 2 above.
4. If incomplete information persists, either an alternative bore path must be chosen, or the facilities installed via open trench.

Approved methods for verifying the location and depth of existing customer owned utilities within private property include:

1. Use a fish tape to locate any unconfirmed drainpipe or conduit.
2. Use sewer as-built/card records for information on depth and location, if available. It is recommended to also look for visual indicators such as a cleanout, locate marks, pipes inside the structure, etc. to support the information on the card.
3. Use technologies such as GPR (Ground Penetrating Radar) or in pipe camera technology.
4. If incomplete information persists, an alternative bore path must be chosen, or the facilities installed via open trench.

Pipe camera technology may be used after installation to verify that the utility has not been damaged. If at any point it is suspected that a sewer cross-bore situation has occurred, then a camera inspection of that facility shall be completed within the area of concern.

Longitudinal Separation

To account for locate inaccuracy and a wandering drill head, cutting tool or missile, gas pipeline, including services, should be installed with a 4-foot minimum longitudinal separation from other underground utilities. When using trenchless installation methods close to other utilities, consideration should be made to pothole them at regular intervals to verify location and separation. Gravity sewer lines, drain fields, steam, and hot water lines require further separation. Refer to Specification 3.15, Trenching and Backfill, “Clearances – Steel and PE Pipelines” for details regarding separation from these utilities.

Depth of Cover

Minimum depth of cover for trenchless pipe installations shall be consistent with Avista standards as outlined in Specification 3.15, Trenching and Backfill, except at waterways. With respect for future accessibility and maintenance of pipe facilities, it is recommended that a maximum depth of cover of 8-feet be established most specifically during HDD operations unless conflicts or conditions exist that require pipe be installed at greater depth (i.e., water crossings, utility conflicts, or geographical features). When crossing waterways, the depth of cover will be dependent upon a number of factors including the length of the bore, geological features, size of crossing, obstructions, etc. Consult Gas Engineering for guidance regarding appropriate depths of cover. To reduce the potential for hydro-fracture extreme care should be exercised when boring at depths less than 20-foot of cover.

Future Locatability

Pipe installed by any form of trenchless technology must be locatable. PE main shall have a tracer wire installed in conjunction with the installation as detailed in Specification 3.13, Pipe Installation – Plastic (Polyethylene) Mains. Steel main shall have a locate wire bonded to the main near the entry or exit location or have other means of attaching locating equipment to identify the pipe. Refer to Specification 3.12, Pipe Installation – Steel Mains for additional information. In situations where traditional locating methods will not be capable of locating the main, due to extreme pipe depths, (>12 feet) marker balls should be located over the pipe installation path. The marker balls should be placed, when possible, at approximately 10-foot spacing and at a depth of approximately 24 inches. The marker balls will be used as a reference, in addition to traditional locating methods, to identify the pipe location. Marker balls should be mapped in GIS to indicate where they have been installed for locating assistance.

Steel – Minimum Radius of Curvature

The following formula is used to determine the minimum radius of curvature (in feet) for steel pipe:
Minimum radius of curvature (feet) = Nominal pipe diameter (inches) x 100
Example: Minimum radius of curvature for 6 inch steel pipe = 6 x 100 = 600 feet

PE – Minimum Radius of Curvature

For plastic pipe, the minimum radius of curvature during trenchless installation is summarized in the table titled Minimum Permanent Bending Radius in Specification 3.13, Pipe Installation, Plastic (Polyethylene) Mains.

HORIZONTAL DIRECTIONAL DRILLING:

General

Horizontal Directional Drilling (HDD) may be suitable for areas in which it is beneficial the avoid excavation at the ground surface.

Permits

Proper permits shall be in place as required by state and local jurisdictions before beginning any HDD project.

Pilot Hole Alignment

The pilot hole alignment shall be established with the desired entry and exit points, desired depth of cover, and consideration to the final pipe curvature during the design phase.

HDD Bore Path

HDD bore site and path selection shall consider several factors including but not limited to the identification of underground obstacles, soil conditions, and suitable bore path alignment. Enough area must be available at the site to allow for the layout of drilling equipment and materials, as well as enough room to allow for proper containment of drilling mud and water. For creek, river, and environmentally sensitive areas, special considerations must be made to prevent hydrofracture and a mitigation plan must be in place to prevent and/or contain any lost fluids. Refer to "Discharge Mitigation Plan" in this specification for additional information regarding what to do in the event of a spill or hydrofracture.

Reaming

For pipe less than 4-inch in diameter, reaming is usually not necessary if soil conditions are good, and the pilot hole has not collapsed. For pipe 4-inch in diameter and larger, once the pilot hole is established it should be enlarged with a reamer. Reaming should be accomplished using push- or pull-reaming passes and large quantities of drilling mud to flush tailings from the hole.
The drill operator is responsible to determine and implement a final reamed hole diameter and other applicable actions that will ensure a successful bore and a pullback of the pipe that results in minimizing damage to the pipe and pipe coating. As a rule of thumb, the size of the final reamed hole should be a minimum of 1.5 times the pipe diameter; however, the size of the reamed hole should not create settlement or cave-in issues. If the bore path is made up of boulders, gravel, and/or cobble, additional swabbing passes and/or a larger final ream pass may be required to prevent damage to the carrier pipe and its coating as applicable.

Pullback

The pipe should be pulled through the bore hole using a pulling head with a swivel joint installed between the pipe and drill stem. The pulling head is typically shaped like a bullet and is one or two pipe diameters larger than the pipe being pulled in. The leading end of the carrier pipe being pulled through the bore hole shall be closed prior to starting pullback to prevent any debris from entering the carrier pipe during installation. The pipe should be supported on rollers or booms at the aboveground work site as it is pulled through the bore hole to prevent buckling or damage caused from dragging along the ground. When possible, it is desirable to fully assemble the product pipe and complete the pullback without stopping to minimize the risk that the pipe will become stuck in the bore hole or that the bore hole will collapse. If there is a delay between the establishment of the reamed pilot hole and the pullback step, swab passes may be required to re-establish the bore hole.

During the pulling operation, both the pulling end and trailing end of the gas pipe should be monitored for continuous and smooth movement. Also, the leading end should be pulled past the termination point, approximately 3 percent of total length being pulled and observed to assure that excessive damage has not occurred to the pipe and to allow for any potential contraction or recovery of the pipe.

When pulling in plastic (polyethylene) pipe, constant monitoring of pullback forces should be performed using a calibrated pressure gauge if available on the pullback equipment. The use of a break-away device or a “weak link” is required. Refer to Specification 3.13, Pipe Installation – Plastic, for pullback force limitations and use of a break away device or “weak link” and pipe recovery.

HDD Discharge Mitigation Plan

The drilling operator shall monitor the drilling operation for any uncontrolled discharge of drilling products. When a risk exists for an undesirable discharge of drilling fluids to the environment the operator shall follow an established discharge mitigation plan that includes at a minimum the following preventative and mitigative measures:

1. Implementation of appropriate silt screening or barriers to prevent release of drilling fluids.
2. Work above the high water mark.
3. Monitor waterways during the drilling operation for any signs of hydrofracture.
4. In the event of an uncontrolled discharge stop the drilling operation.
5. Suspend pumping drilling mud into the bore hole.
6. In the event of a hydrofracture, minimize the hydraulic pressure in the bore hole by removing accessible drilling fluids.
7. Clean up (where possible) the discharged fluid.
8. Immediately notify the Avista Cultural/Environmental Permits Coordinator, at 509-495-2559.
9. Do not resume drilling without the approval of the permit coordinator and the project manager.

PIPE SPLITTING:

General

The trenchless pipe splitting method is suitable for the trenchless replacement of existing steel and PE gas pipelines with existing diameters ranging from 1/2-inch to 8-inches. The newly inserted pipe must be the same nominal size or smaller than the existing host pipe.

The splitting of an existing steel or PE pipeline is to be accomplished with a dedicated cutter assembly and expanding head. An expanding head coupled behind the cutter assembly further opens the split pipe and compresses any displaced ground material into the surrounding ground.

The expanding head incorporates a new pipe attachment coupling or device that enables the new replacement pipe to be secured and towed behind the expanding head. The cutter assembly is pulled by a small diameter rigid steel rod or cable controlled by an approved pulling device.

Determining Factors

When determining whether an existing gas line (host pipe) should be considered for replacement by this method, the following shall be considered:

- Pipe size
- Pipe Material
- Pipe repair clamps on existing line
- Bends in the line
- Length of line to be replaced
- Burial depth
- Surrounding ground material
- Suitable insertion and pull pit locations
- Existing utility locations
- Any other condition that may prevent successful pipe replacement by this method

Equipment Requirements – Steel or PE

The equipment suitable for performing the pipe splitting process depends upon the application. For steel or PE pipe splitting it is acceptable to use a hydraulically operated rod pulling machine complete with engine or electrically driven hydraulic power supply unit such as a Hammerhead HydroBurst HB3038 or HB5058 static rod pulling system coupled to dedicated Pipe Splitter or equivalent. A directional boring machine may also be utilized for this process.

Each individual rigid steel pull rod section shall have its outside diameter small enough to be inserted into the host pipe to be replaced. The pull rod shall have adequate flexibility to negotiate gradual bends in existing host pipe during push out and pull back operation. The pipe splitter assembly shall consist of a robust steel body housing the appropriate steel roller cutter disks or fins and rear expander head with new pipe attachment device.

Equipment Requirements - PE

For PE pipe, the equipment suitable for performing the splitting process must be of sufficient size and type for the work being performed. It is acceptable to use the following mechanical devices:

- Backhoe, excavating equipment
- Hydraulically operated bore equipment
- Mechanical cable puller

A pipe splitter assembly shall consist of either a robust steel body housing the appropriate steel roller cutter disks or fins and rear expander head or a robust steel body larger than the diameter of the pipe with fin/knife like barbs welded to the expanding body. Both options will incorporate a new pipe attachment device.

Procedure

During the operation, there must be constant communication between the operator of the mechanical pulling device and the person at the entry pit, either by means of hand signals or two-way communication. Do not enter the receiving pit while the pulling device is in operation.

Refer to “Pullback” in this section for additional information, but a break away device or a “weak link” (refer to Specification 3.13) shall be used ahead of the new PE pipe being pulled. Install a minimum of two tracer wires with the new pipe.

Before beginning the operation, insert a camera to verify the location of known fittings. Excavate and expose identified fittings and remove, if possible, prior to splitting. Cut the services from the main and remove the mechanical fittings if possible. On locations where services will be tied back in to the main, cut out the existing host pipe in this vicinity to aid the installation of the new service tee.

PNEUMATIC MISSILING/PIERCING:

General

The use of pneumatic missiles or piercing tools as a trenchless installation method is suitable for gas main and service pipes with diameters ranging from 1/2-inch up to 2-inches in size if ground conditions support this installation method. Typically, this method is used for PE installations less than 100 feet in length.

Determining Factors

When determining whether a new gas line should be installed by this method, the following shall be considered:

- New pipe size
- Length of installation
- Burial depth
- Surrounding ground material (Ground fill, layering, compaction, etc.)
- Suitable insertion and pull pit locations
- Existing utility locations
- Any other condition that may prevent successful pipe installation by this method

Missile Alignment Procedure

The missile alignment shall be established with the desired entry and exit points defined and desired depth of cover established prior to installation. Prior to the operation of a pneumatic missile or piercing tool, all required tools and equipment should be inspected to ensure they are safe for use. Inspect the project site to identify any potential hazards or obstructions. Call for locates, pothole and verify existing utilities per the “Tracking and Potholing” section of this Specification. Excavate the entry and exit pits and determine the length of the bore. It is recommended that the air hose be marked to aid in tracking and monitoring of progress. Use the appropriate alignment tools to line up the missile or piercing tool. Operate the tool per the manufacturer’s instructions. During operation, walk the bore path and track the progress of the pneumatic tool. Once the bore hole is complete pullback or insert the new carrier pipe as necessary. Protect the leading end of the pipe being installed to prevent debris from entering the pipe during pullback or insertion.

3.2 JOINING OF PIPE

3.22 JOINING OF PIPE - STEEL

SCOPE:

To establish a uniform method for initial and renewal qualification of welders, weld procedure qualification, and to define acceptable welding practices. Welding performed on the pipeline system shall be in compliance with the Code of Federal Regulation, Title 49, Part 192. Welding performed in the state of Washington shall comply with WAC 480-93-080.

REGULATORY REQUIREMENTS:

§192.221, §192.225, §192.227, §192.229, §192.231, §192.235, §192.241, §192.243, §192.245

WAC 480-93-080

OTHER REFERENCES:

API 1104 – Welding of Pipelines and Related Facilities
API 1104 Appendix B – In Service Welding
ASME/ANSI B31.8 – Gas Transportation and Distribution Piping Systems

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design – Steel
Spec. 3.12, Pipe Installation – Steel
Spec. 3.32, Repair of Damaged Pipelines – Repair of Steel Pipe

WELDER QUALIFICATION REQUIREMENTS:

General

Pipeline welding shall be performed by welders or welding operators tested and qualified by Avista and qualified to API 1104*. Employees qualified to complete production welds shall be qualified to this standard and applicable sections of API 1104. Welders qualified to complete in-service welds shall be qualified to API 1104 and may also be qualified to applicable sections of API 1104 – Appendix B. Individuals qualified to this standard also satisfy the skills required for Visual Inspection of the Weld (221.130.005). Welds that will not be exposed to the test pressure or that will not be a part of the gas carrying system need not be completed by a qualified welder or to a qualified weld procedure.

Welding processes commonly used in pipeline welding procedures include shielded metal arc (SMAW) and gas metal arc (GMAW).

(*) Denotes the edition of API-1104 currently adopted under CFR 49, Part 192, 192.7(b)(9).

Qualification of Welders

No welder may weld with a particular welding process unless, within the preceding 6 calendar months, the welder has engaged in welding with that process. Alternatively, welders may demonstrate they have engaged in a specific welding process if they have performed a weld with that process that was tested and found acceptable under section 6, 9, 12, or Appendix A of API 1104 within the preceding 7-1/2 months. Welders may maintain an ongoing qualification status by performing full circumferential welds, tested, and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7-1/2 months. If the initial welder qualification occurs after June 30th, the welder does not need to requalify the same calendar year. Initial qualification welds shall be evaluated by destructive testing. Re-qualification welds may be determined acceptable by non-destructive (radiographic) or destructive testing. If non-destructive testing is used to re-qualify a welder, the technician evaluating the weld must include the name of the welder being re-qualified on the non-destructive testing evaluation form. Welders who fail to re-qualify within the 7-1/2 month interval shall complete the initial qualification requirements when qualifying to weld.

Welders shall be initially qualified per Section 6.3, “Multiple Qualification” of API 1104 and by welding process (GMAW and/or SMAW). If a welder desires to weld with multiple processes a successful initial qualification or re-qualification test shall be completed with all desired processes. One of the following qualification tests shall be completed as appropriate for the welder’s area of service and qualifications.

Welders shall be qualified by the following variables:

1) Process (GMAW and/or SMAW)
2) Direction of welding (Vertical Uphill and/or Vertical Downhill)
3) Diameter (6.625-inches or 12.75 inches for All Diameters)
4) When welding with the SMAW process a change of filler metal classification from Group 1 or 2 to Group 3 or from Group 3 to Group 1 or 2.

A welder shall only weld within the parameters of their qualifications. Re-qualification is required if any of the above essential variables is changed.

<u>Recommended Initial Qualification Test – Production and In-service <60 psig</u>

Process: GMAW or SMAW
Qualification Procedure: E6010* or ER-70-S* and as determined by material yield strength and process.
*Note: The qualification will only qualify the welder to weld downhill.
Qualification Material: 6.625 inch or 12.750 inch Diameter with a wall thickness ≥ 0.250 inches.
Yield Strength: ASTM A53, Grade B thru API 5L Grade X52
Weld Test 1: Butt Weld, Horizontal Fixed Position
Weld Test 2: Layout, Cut, Fit, and Weld a full-sized branch on pipe connection. A full-size hole shall be cut into the run. Weld shall be completed in the horizontal fixed position with the branch down.
Acceptance Criteria:
<u>Butt-</u>

A) Visual per API 1104, Section 6.4
B) Destructive testing per API 1104, Section 6.5

<u>Branch -</u>

A) Weld shall exhibit a neat, uniform workman like appearance.
B) Weld shall exhibit complete penetration around entire circumference.
C) Complete root beads shall not contain any burn through of more than ¼ inch. The sum of the maximum dimensions of separate unrepaired burn-through in any continuous 12 inch length of weld shall not exceed 1/2 inch.
D) Destructive testing per API 1104, Section 6.3.1 (4 Nick Breaks).

Welder Qualifications: A welder who has successfully completed both of the qualification welds shall be qualified to complete welds on all non-pressurized piping and weld on in-service piping with a Maximum Allowable Operating Pressure (MAOP) less than or equal to 60 psig with the Process qualified (SMAW or GMAW) in all positions, wall thicknesses, joint designs, fittings, and diameters ≤ 6.625 inches or all diameters if test completed on 12.750 inch material.

Recommended Initial Qualification Test – In-Service Welding >60 psig

Process: GMAW or SMAW
Qualification Procedure: E7018* or ER70-S as appropriate and as determined by material yield strength and process.
*Note: This qualification will qualify the welder to weld uphill for E7018.
Qualification Material: 12.750 inch Diameter with a wall thickness ≥ 0.250 inches.
Yield Strength: ASTM A53, Grade B through API 5L Grade X52
Weld Test 1: Layout, Cut, Fit, and Weld a 12.750 inch diameter sleeve 8 inches long onto a 12.75 inch diameter pipe 1 inch long. Weld shall be completed at an angle 45 degrees from the Horizontal (6G Position).
Welder Qualifications: A welder who has successfully completed the qualification weld and subsequent destructive testing as outlined in API 1104, shall be qualified to weld with the Process Qualified (SMAW or GMAW), on all pressurized systems, in all positions, all diameters, all wall thicknesses, all material grades, and all branch connection sizes.

Recommended Re-Qualification Test – Production and In-Service

Process: GMAW or SMAW
Qualification Procedure: E6010, E7018, or ER-70-S and as determined by material yield strength and process.
Qualification Material: 6.625 inch or 12.750 inch Diameter with a wall thickness ≥ 0.250 inches.
Yield Strength: ASTM A53, Grade B through API 5L Grade X52
Weld Test 1: Butt Weld, Horizontal Fixed Position
Welder Qualifications: A welder who has successfully completed the re-qualification weld shall be qualified to weld within the variables of their original qualification.

Weld Testing

Pressure Controlmen of Avista are the only personnel authorized to administer weld testing. The person administering the weld test shall also be the inspector. Each weld test shall be completed using an approved welding procedure. The individual administering the weld test shall document all appropriate information on the Welder Qualification Test Report (Form N-2562), including results of the destructive test as outlined in API 1104. Records of welder qualification shall be retained for at least 6 years from the date of qualification.

Retesting after Failure

A welder who has failed the qualification test may be allowed to retest no sooner than 48 hours later and after completing further practice and/or training. A welder who has failed the qualification test shall not perform any welding on gas facilities until they pass the qualification test.

Welder Certification Card

Welders passing the qualification test and destructive testing shall be issued a company Welder Certification card by the evaluator performing the weld evaluation test. This certification card should indicate the name of the qualified individual, date of qualification, expiration date, process qualified (SMAW or GMAW), Qualification Parameters (In-service ≤ 60 psig and Production or High Pressure), Qualified Diameter (≤ 6.625-inches or All Diameters), approved weld direction, approved filler metal groupings when appropriate, and the name of the evaluator. The qualified individual must have the card available for inspection when performing welding in the field. Welder Certification cards shall be valid for 6 months.

WELD CERTIFICATION CARD

Front of Card:

AVISTA

WELDER CERTIFICATION

Welder ______________________ No. __________

Certification Date ______________________

Expiration Date* ______________________

Qualified for Welding Process

SMAW ☐

(See back of card) GMAW ☐

*Card holder must call for test 2 weeks in advance.

Qualified By: ______________________

N-2691 (9-20)

Back of Card:

Process	Diameters	Direction of Welding	Filler Metal Grouping	Pressure Class
☐ SMAW	☐ ≤ 6.625 ☐ All Dia.	☐ Uphill ☐ Downhill ☐ All	☐ Group 1 E6010 ☐ Group 2 E8010 ☐ Group 3 E7018	☐ ≤ 60 psig ☐ All Pressures
☐ GMAW	☐ ≤ 6.625 ☐ All Dia.	☐ Downhill	☐ Group 5 ER70-S	☐ ≤ 60 psig ☐ All Pressures

Note: Welder is qualified to the variables listed above. The welder may complete a weld using any qualified Avista weld procedure within the parameters of the employees' qualifications.

WELD PROCEDURE QUALIFICATION REQUIREMENTS:

General

Detailed weld procedures shall be developed and qualified in accordance with API 1104, Section 5 and copies of these procedures shall be on site where welding is being performed. Procedures shall be retained and followed when completing welds.

Weld Procedure Qualification

Details of each qualified procedure shall be recorded on a Procedure Qualification Record (PQR). The qualification record shall include the details as outlined in Section 5.3, API 1104. The PQR shall be maintained as long as the procedure is in use.

The quality of the welds used to qualify the procedures shall be determined by destructive testing as detailed in API 1104, Section 5.6 for Butt Welds and Section 5.8 for Fillet Welds.

A procedure must be re-established as a new procedure specification and must be re-qualified when any of the essential variables listed in API 1104 Section 5.4.2 are changed as listed below:

- Welding Process – Change in weld process
- Base Material Yield Strength Grouping – Change in base metal grouping
- Joint Design – Major change in joint design
- Position – A change from roll to fixed, or vice versa
- Wall Thickness Grouping – A change from one wall thick group to another
- Filler Metal – Change in filler metal group
- Electrical Characteristics – Change from DC electrode positive to DC electrode negative or vice versa. A change in current from DC to AC or vice versa
- Time between Passes – An increase in the maximum time between passes
- Direction of Welding – Change from uphill to downhill
- Shielding Gas Flow Rate – Change in shielding gas
- Shielding Flux – A change in shielding flux that changes the AWS classification number
- Speed of Travel – Change in speed range
- Preheat – Decrease in specified minimum preheat temperature

Procedure changes other than those listed above are allowed when specifically authorized by the company, as provided for in Section 5.4 of API 1104. Authorized changes shall be noted on a revised procedure specification.

Weld Procedure Groupings

Production weld procedures shall be grouped as specified in API 1104 and as follows:

1) Process – (SMAW, GMAW)
2) Base Material – (Yield Strength ≤ 42,000 psi, Yield Strength >42,000 psi and < 65,000 psi, Yield Strength > 65,000 psi requires a separate procedure for each pipe grade)
3) Diameter – (Dia. < 2.375 inches, Dia. 2.375 inches through 12.750 inches, Dia. >12.75 inches)
4) Wall Thickness – (w.t. < 0.188 inches, w.t. 0.188 inches through 0.750 inches, w.t. > 0.750 inches)
5) Weld Position – Fixed or Rolled

In-service welding procedures will be grouped as follows:

1) Process – (SMAW, GMAW)
2) Base Material – (Yield Strength ≤ 42,000 psi, Yield Strength >42,000 psi and < 65,000 psi, Yield Strength > 65,000 psi requires a separate procedure for each pipe grade)
3) Diameter – (Dia. < 2.375 inches, Dia. 2.375 inches through 12.750 inches, Dia. >12.750 inches)
4) Wall Thickness – (w.t. < 0.188 inches, w.t. 0.188 inches through 0.750 inches, w.t. > 0.750 inches)

When qualifying a weld procedure, the procedure qualification material shall be of the highest yield strength material in the category. When material of lower yield strength is selected the procedure shall only be qualified to the maximum yield strength tested.

WELDING CONTROL REQUIREMENTS:

Weld Type/Procedure Selection

Prior to the welding of pipe or fittings, the welder must first select the proper welding procedure. When welding pipe or fittings of two different yield strengths the procedure for the material of the highest yield strength shall apply. If welding on intermediate pressure pipe and the grade is unknown, select the welding procedure for material grade X46 ≤ X52. If welding on high pressure pipe and the grade is unknown, contact Gas Engineering for assistance determining the correct welding procedure.

Weld procedures shall be located on-site where welding is being performed.

Piping, fittings, and appurtenances to be arc welded shall be welded using one of the following arc welding processes:

- Shielded metal arc welding (SMAW)
- Gas metal arc welding (GMAW)

This standard covers the SMAW process using cellulose electrodes (E6010) for production welding or in-service welding on systems with an operating pressure of 60 psig or less and GMAW or SMAW using a cellulose electrode (E6010) for the root pass followed by a low-hydrogen (E7018) electrode for the filler and cap pass for production welding or in-service welding on systems operating at any pressure or stress level.

Welding on pipe greater than 12 inch diameter (nominal) should be welded simultaneously by a minimum of 2 welders on opposite sides of the pipe (often referred to as brother-in-law welding). If this is not possible, the single welder shall weld one quadrant (1/4 of circumference) at a time, moving to the opposite quadrant after each pass, and welding the opposite quadrant to offset expansion/contraction stresses due to welding.

Weld Preparation

Tools and equipment used for welding shall be of a capacity suited to the work to be performed.

The welding operation must be protected (shielded) from weather conditions (rain, snow, ice, or high winds) that would impair the quality of the completed weld.
Prior to the welding, the weld groove and the adjacent surfaces shall be cleaned and kept free of all dirt, paint, rust, scale, moisture, oil, grease, or other foreign material harmful to welding. Cleaning should be performed by filing, hand or power wire brushing or grinding, and/or using approved solvents.

Before sections of pipe and fittings are assembled for welding, all rust, scale, slag, dirt, liquids, or other foreign matter shall be removed from the inside surface of the pipe by swabbing with clean rags or by other acceptable methods. Responsible person(s) on the job shall ensure compliance with this requirement.

Non-Destructive Pre-Inspection

Prior to welding or cadwelding on a pipeline, a visual inspection of the carrier pipe shall be completed. Visual inspection shall ensure the surface is free of manufacturing defects, corrosion, dents, scrapes, gouges, or other anomalies that may be detrimental to the pipeline.

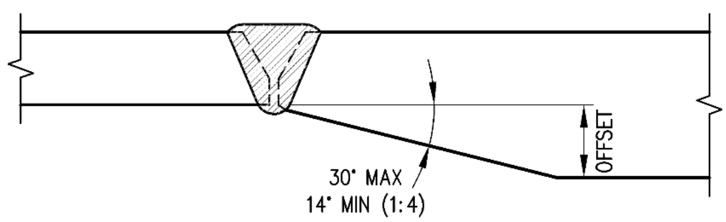
When welding appendages, stopper fittings, service tees, cadwelding, etc. to high pressure in-service (> 60 psig) piping, the area of the carrier pipe to be welded should be inspected to verify wall thickness and verify for the absence of laminations using ultrasonic test equipment prior to welding. If inspection of the carrier pipe is required in the area of the long seam weld protrusion, the cap of the weld may be removed to a smooth contour with the adjacent pipe using a powered sanding disk.

On pipe with suspected or known long seam anomalies, the long seam weld should be inspected using an X-Ray, shear-wave ultrasonic or magnetic particle inspection prior to welding to verify the integrity of the carrier pipe and the absence of subsurface cracks, discontinuities, or inclusions.

Pipe End Alignment

ASME B31.8, Appendix I shall govern the end preparations for butt welding regarding internal and external offset. Pipe and/or fittings joined by welding shall be aligned to minimize any offset (high-low) of pipe wall surfaces around the circumference of the pipe. For pipe designed at less than 20 percent SMYS and the nominal wall thickness of the adjoining ends does not vary more than 1/8-inch, no special treatment is necessary provided adequate penetration and bond is accomplished in welding.

If the internal offset exceeds 1/8-inches for pipe designed at < 20 percent SMYS or 3/32-inches for ≥ 20 percent SMYS, a piece of transition pipe with a wall thickness between the two shall be used or the use of a back bevel (14 degrees minimum and 30 degrees maximum) made on the inside end of the thicker section. External offset shall be limited to the out-of-roundness and pipe and fitting end diameter tolerances given in the material specifications. The illustration below shows the use of a back bevel.



If the pipe or fitting ends are defective or damaged (scratches, gouges, dents, etc.), the ends shall be re-beveled.

The joint design and fit up shall be governed by the appropriate weld procedure. The Root-opening gap for SMAW and GMAW welds shall preferably be 1/16 of an inch, not to exceed 3/32 of an inch. The joint design for Fillet welds shall ensure a full penetration weld.

Hammers used for aligning pipe and fittings must be bronze or brass faced. Care should be exercised to avoid denting, gouging, or scratching the pipe and/or fittings.

When aligning abutting lengths of pipe for welding, the longitudinal seams shall be staggered (no closer than 3 inches).

The pipe or component must be aligned to provide the most favorable condition for depositing the root bead and the alignment must be maintained while the root bead is being deposited. A lineup clamp should be used for butt welds on pipe in the field with a nominal diameter of 2-inches or larger. If a lineup clamp is used it shall be left in place until the root bead is at least 50 percent completed and equally deposited around the weld groove. No stress (pipe movement) shall be placed on the weld until the weld is complete.

Miter Joints

Miter joints are not allowed. Inflections are to be completed using an appropriate pipe bending machine or fittings. Refer to Specification 3.12, Pipe Installation - Steel Mains for details related to mitering weld elbows.

Circumferential Weld Separation

The minimum separation between any two circumferential welds, wherever possible, shall be:

One pipe diameter for welds on pipelines other than station piping, but never less than 3 inches (Note: Fittings may be welded back to back)

Six inches for station piping or fabricated assemblies 6 inch nominal O.D. and larger. One pipe diameter for piping smaller than 6 inch nominal O.D.

One inch, as measured along the inside arc radius of any welding elbow and transverse segments of these elbows, 2 inch or more in nominal diameter

Adequate working clearance shall be provided and maintained around the pipe and/or fittings at all points to be welded so that the work can be performed safely.

Branch connection welds including reinforcing member welds, should be located at least 3 inches away from circumferential welds whenever possible.

Maintaining minimum weld separation assures adequate ductility of the welded assembly and avoids stress concentrations.

Preheating

Preheating pipe prior to completing a weld helps ensure a superior weld by removing moisture and contaminates from the surface of the steel. Preheating pipe ensures a proper temperature can be maintained when completing in-service welds and reduces the potential for cracking.

Refer to the individual welding procedures for when preheating is required.

The preheated area shall be at least 6 inches wide, centered about the weld, and shall extend around the entire circumference of the pipe or fitting.

Preheat temperature shall be checked with temperature sensitive crayons, such as "Tempilstick", pyrometer or infrared gun, at the weld area outside of the weld groove.

If welding is interrupted, the weld area shall again be preheated before welding is resumed.

Post Heat Weld Treatment

Avista's current welding procedures do not require post heat weld treatment.

Over-Cooling

Welding on pipelines experiencing high gas flow rates should be avoided as high gas flow rates may cool welds too quickly and cause weld defects including weld cracking.

Welds shall be allowed to air cool in ambient conditions unless a post heat treatment is specified in the welding procedure. Water, forced air, or other means of expediting cooling shall not be used.

Grounding Devices

Grounding devices shall be positively attached to the pipe in such a manner to prevent arcing between the grounding device and pipe. No welding electrode or grounding device shall be permitted to arc to the pipe except in the actual bevel being welded. Grounds should not be located on flanges or threaded components such as caps or plugs as this may cause arcing across the threads. Grounds should be located as near as practical to the weld and should not be placed on the opposite side of a valve.

Butt Welding Technique

Horizontal and vertical fixed position shielded metal-arc welding with cellulose electrodes (AWS Exx10,) or wire electrode (ER70S-2, 6) shall be performed by the "Downhill" method. Welding with low-hydrogen electrodes (AWS Exx18) shall be performed by the "Uphill" method.

Pipes to be welded shall be aligned and the root opening (gap) shall be aligned as in the weld procedure specification and should suit the preference of the welder responsible for the integrity of the root bead. During alignment and tacking, the joint is held together by a lineup clamp. Care must be taken during joint alignment and preparation to ensure full penetration and complete fusion during root bead (first pass) deposit.

Depositing Root Bead and Hot Pass

Strike the arc in the weld groove only. Thoroughly clean the root before applying hot pass (second bead). Disc grinding shall be used to remove bumpy starts and slag, improve bead contour, or remove excessive "wagon tracks" before applying the hot pass. Wagon tracks are slag-filled crevices on either side of the root bead.

Applying the hot pass with sufficient heat (amperage) will melt out shallow wagon tracks and float any remaining slag to the surface. Start the hot pass immediately after completion of the root bead as delineated in the Weld Procedure, typically within 5 minutes.

Filler and Cover Passes

A side-to-side weave motion is used when applying the filler passes. Filler metal shall be added to any concave portion of the filler passes, before applying the cover pass.

On heavy wall pipe and fittings (greater than standard wall thickness) where the welding groove is wide, more than one bead per layer shall be used for filling in the "downhill" direction.

Strip capping shall be used for making the cover pass when welding in the vertical fixed position. Wash passes are not acceptable when welding in this position.

Filler and cover passes made using the weave motion when welding downhill on horizontally fixed pipe and fittings shall be no wider than four times the electrode diameter. Welds shall be uniform and without undercutting.

Two beads shall not be started at the same location. The face of the completed weld should be approximately 1/8 inch greater than the width of and centered on the original groove. At no point shall the crown surface be below the outside surface of the pipe, nor should it be raised above the parent metal more than 1/16-inch.

Filler and cover passes made using the weave motion welding uphill on horizontally fixed pipe and fittings shall be no wider than 5/8-inch using 3/32-inch diameter rod and 1-inch using 1/8-inch diameter rod.

On pipe or fittings in the vertical fixed position, each weld layer shall be deposited with multiple passes in the horizontal plane. Wash passes shall not be permitted.
The completed weld shall be thoroughly brushed and cleaned.

Roll Welding

Roll welding is not permitted. Repositioning of the pipe joint is permitted as long as all welding is performed while the pipe is in a fixed position.

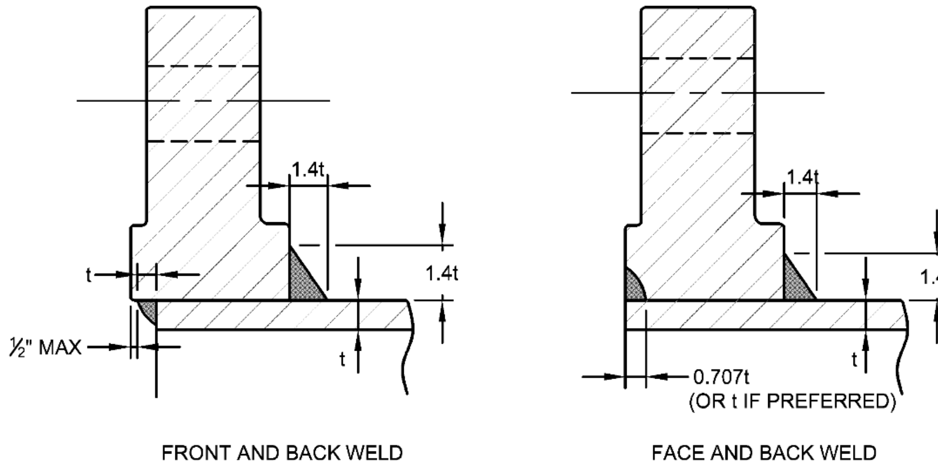
Fillet Welding

In-service circumferential fillet welds on sleeves for high-pressure transmission pipelines with an MAOP of 20 percent SMYS or greater shall be made using low-hydrogen electrodes E7018 or GMAW using ER70S-2, 6 wire. Fillet welds on sleeves and fittings for high pressure pipelines operating at an MAOP less than 20 percent SMYS may be completed using an E6010 root with E7018 filler and cap however an all low hydrogen process (GMAW) is preferred. For intermediate pressure distribution pipelines with and MAOP 60 psig or less, AWS A5.1 (E6010) electrodes are acceptable for fillet and longitudinal welds.

Fillet welds shall be essentially flat with full throat and legs of uniform length in accordance with the welding procedure. Undercutting in the fillet weld where the leg meets the parent metal is prohibited. If undercutting occurs in this area, it shall be ground out and a reinforcing pass applied in the undercut area.

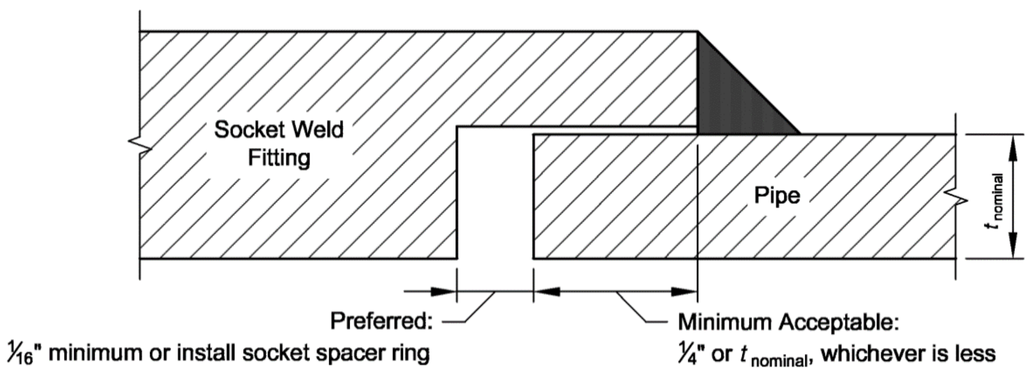
The welder shall use caution and experience when welding on pressurized piping. It is prudent to know the wall thickness of the carrier pipe when welding so that Speed of Travel, Voltage, and Amperage can be controlled properly within the parameters of the procedure to produce a satisfactory weld without burn through. Extreme care shall be exercised by an experienced welder when welding large fittings to thin wall pipe to ensure the proper control of heat input to ensure good penetration without burn through.

As recommended per ANSI B31.8, slip flanges should be fillet welded on both the front and the back of the fitting per the diagrams below.



Socket Welding

Socket welds shall be made with a space between the pipe and socket weld fitting within the ranges and dimensions shown in the diagram below. This will help eliminate stresses in the weld metal due to thermal expansion of the pipe during the welding process. If the end of the pipe is cut, the end should be square so the space between the pipe and socket weld fitting is uniform. Refer to the diagram below for an illustration.



Non-Destructive Testing (NDT) Requirements

Welds on pipelines with an MAOP that results in a pipe stress level of 20 percent or more of SMYS shall be non-destructively tested by any process other than trepanning that will clearly indicate defects that may affect the integrity of the weld. NDT inspection should also be considered for gas pipelines being installed on a bridge with an MAOP of 250 psig or more. The NDT results shall be interpreted by a person certified to Level II in accordance with recommendations by the American Society for Nondestructive Testing or other recognized organization when practical. The acceptability of a weld that is non-destructively tested or visually inspected shall be in accordance with API 1104 Section 9. The person evaluating the weld must include the name of the welder on the non-destructive testing evaluation form.

When NDT testing is required, the following percentages of each day's field welds selected at random by the Operator must be examined using NDT over their entire circumference (when there is more than one welder, a sample of each welder's work for each day must be included in the random selection):

- 10 percent (at a minimum) of welds - Class 1 locations
- 15 percent (at a minimum) of welds - Class 2 locations
- 100 percent of welds - Class 3 and 4 locations and at crossings of major or navigable rivers, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings. Exception: Where 100 percent is impractical, at least 90 percent of the welds shall be non-destructively inspected. (Any girth weld not tested must have been impracticable to test)
- 100 percent of welds at pipeline tie-ins, including tie-ins of replacement sections.

When NDT testing is required, a record must be retained for the life of the pipeline showing by milepost or by geographic feature, the number of girth welds made, the number non-destructively tested, the number rejected, and the disposition of the rejects.

Non-destructive testing of welds shall be completed by a third party contractor. Contractor work shall be completed in accordance with contractor qualified procedures accepted by Avista. Contractor shall maintain qualified procedures in accordance with industry standards and must be available on the job site. Avista shall maintain a copy of current contractor qualified procedures.

Welds shall be visually inspected by an individual qualified in visual inspection. A welder may visually inspect their own welds when qualified to do so. Inspection by the welder does not preclude external inspection to ensure conformance and acceptability by the company. Visual Inspection Criteria are listed within this specification for reference.

In addition to visual inspection of the weld, the welder or weld inspector shall ensure that the weld is completed in a workmanlike manner and in accordance with the procedure. Procedure inspection criteria should include the following:

1. Inspect the joint alignment and fit up.
2. Preheat requirements are being met, if required.
3. Use of proper electrodes for the procedure being used.
4. Check the amperage settings with an ammeter and verify the voltage settings to make sure that they fall within the ranges specified for the electrode size and type for the weld procedure being used.
5. Verify the speed of travel is within the parameters of the procedure by timing and recording the actual welding time for each pass needed for the procedure and calculate the speed of travel in inches per minute.
6. Check for potential weld defects as listed within this specification.
7. On completion of weld, check for appearance and cap size.

Determining Speed of Travel

Use the following formulas to determine the speed of travel in inches per minute:

Speed of Travel (inches per minute) = Distance (inches) ÷ Total Seconds x 60

Example: Determine the speed of travel if a 5-1/2" long weld was made in 39 seconds.

Travel Speed = 5.5 inches ÷ 39 seconds x 60
= 8.46 inches per minute

If the welding time was over a minute, use the following formula to convert welding time to seconds:

Total Seconds = Minutes x 60 + Seconds

> Example: Determine the welding time in seconds if the weld took 2 minutes and 12 seconds to complete.
>
> Total Seconds = 2 minutes x 60 + 12
> = 132 seconds

Removal or Repair of Weld Defects or Cracks

With the exception of shallow crater cracks, no weld containing cracks, regardless of size or location shall be acceptable. Welds containing cracks and other unacceptable defects that are detected during or immediately after welding shall be repaired or removed.

Cracks to be repaired in butt welds or fillet welds of branch connections or sleeves that are more than 8 percent of the weld length must be cut out and replaced.

Cracks to be repaired of any length in longitudinal welds in pipe operating with an MAOP of 20 percent or more of SMYS or 500 psig or greater must be repaired by replacing the pipe segment. Cracks in longitudinal welds in pipe operating with an MAOP below 20 percent of SMYS or 500 psig may be repaired using the patching, sleeving, or canning repair methods given in Specification 3.32, Repair of Steel Pipe.

If a longitudinal or branch connection weld has a crack that is 8 percent or less of the weld length, the weld may be repaired by grinding, filling, or machining the repair cavity to bright clean base metal, and fill welding. Refer to Specification 3.32, Repair of Steel Pipe for other permissible repair methods.

Repair of a crack or defect in a previously repaired area can only be repaired by an appropriate sleeve or the section cut out and replaced.

Electrode Storage

Cellulose electrodes including E6010 shall be stored in protected dry storage areas and shall not be heated. (Store at room temperature 60-80 degrees F).

To perform properly, Low-Hydrogen E7018 electrodes must be stored and handled in a manner which will prevent absorption of moisture. Low hydrogen electrodes shall be either stored in their manufacturer's unopened container or a holding oven or electrode warmer which must be maintained at 250-350 degrees F. If used immediately, low-hydrogen electrodes may be issued for use directly from freshly opened hermetically sealed containers. Low hydrogen electrodes which have been exposed to high moisture conditions or have been removed from the holding oven or electrode warmer for a length of time exceeding four hours shall be discarded.

Electrodes in unopened sealed containers remain dry indefinitely under good storage conditions. The storage area should be enclosed, clean, dry, and have adequate facilities for safe storage to prevent deterioration.

Welders who become qualified to use low-hydrogen electrodes shall be thoroughly instructed in storage and handling requirements.

Visual Inspection

WELD DEFECTS / CAUSES / VISUAL CHECK:

Inadequate Penetration without high-low is an incomplete filling of the weld root.

Causes – Improper welding technique, insufficient joint space, or improper fit-up.

Visually check - Joint space and fit-up, and conformance to the weld procedure.

Inadequate Penetration Due to High/Low is defined as the condition that exists when one edge of the root is exposed (or unbonded).

Cause - Because adjacent pipe or fitting joints are misaligned.

Visually check - For proper use and adjustment of clamps.

Incomplete Fusion is defined as a surface imperfection between the weld metal and the base material that is open to the surface. It can be in the root or in the cap.

Cause – Improper welding technique.

Visually check - For conformance to welding procedure including amperage and travel speed and joint design.

Incomplete Fusion Due to Cold Lap is defined as an imperfection between two adjacent weld beads or between the weld metal and base metal that is not open to the surface.

Cause - Improper welding technique.

Visually check - For conformance to the welding procedure, proper interpass cleaning. Welding angle can contribute to this defect.

Internal Concavity is defined a bead that is properly fused to and completely penetrates the pipe wall thickness along both sides of the bevel, but whose center is somewhat above the inside surface of the pipe wall.

Cause – Excessively wide joint space and improper welding technique.

Visually check - For conformance to the welding procedure including joint space.

Burn-Through is defined as a portion of the root bead where excessive penetration has caused the weld puddle of the root or hot pass to be blown into the pipe causing a rounded contour in the middle of the root pass.

Causes – Root pass too thin, excessive, or improper grinding of root pass, pipe out of alignment.

Visually check - For conformance to the welding procedure including pipe alignment.

Slag Inclusions is defined as a nonmetallic solid entrapped in the weld metal or between the weld metal and the parent metal. Elongated slag inclusions are usually called “wagon tracks”.

Cause – Flux coating particles trapped between weld passes or between the pipe bevel and the weld metal.

Visually check - Proper cleaning between passes, proper amperage for the electrode diameter, and proper voltage.

Porosity is defined as gas trapped by solidifying weld metal before the gas has a chance to rise to the surface of the molten puddle and escape. (A “gas pocket” is a term of porosity that is intended to describe a pore within the body of the weld while a “pinhole” describes porosity on or near the edge of the cap pass).

Visually check - For proper cleaning of pipe bevels and root face. Electrodes that may have absorbed excessive moisture or been frozen can produce porosity.

Undercutting is defined as a groove melted into the parent metal to the toe or root of the weld and left unfilled by weld material.

Cause –High amperage and a long arc; incorrect electrode position.

Visually check - For conformance to the welding procedure and proper machine setting for arc force (open circuit voltage).

APPENDIX A - WELD PROCEDURE INDEX

BUTT WELDS - PRODUCTION (NON-PRESSURIZED)					
PROCEDURE NUMBER	**WELDING PROCESS**	**FILLER MATERIAL**	**PIPE/FITTING O.D. DIAMETER RANGE**	**PIPE/FITTING WALL THICKNESS RANGE**	**MATERIAL GRADE[2]**
B1	SMAW	E6010	< 2.375”	< 0.188”	Gr. B
B3	SMAW	E6010	2.375” ≤ 12.750”	< 0.188”	Gr. B ≤ X42
B4	SMAW	E6010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
B5	SMAW	E6010	>12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
B6	SMAW	E6010	2.375” ≤ 12.750”	< 0.188”	X46 ≤ X52
B7	SMAW	E6010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52
B8	SMAW	E6010	>12.750”	0.188” ≤ 0.750”	X46 ≤ X52
B9	SMAW	E7018	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X65
B17	SMAW	E8010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52
B19	SMAW	E8010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X65
B21	GMAW	ER-70-S-6	< 2.375”	< 0.188”	Gr. B
B23	GMAW	ER-70-S-6	2.375” ≤ 12.750”	< 0.188”	Gr. B ≤ X42
B24	GMAW	ER-70-S-6	2.375” ≤ 12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
B26	GMAW	ER-70-S-6	2.375” ≤ 12.750”	< 0.188”	X46 ≤ X52
B27	GMAW	ER-70-S-6	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52
B29	GMAW	ER-70-S-6	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X65
FILLET WELDS - PRODUCTION (NON-PRESSURIZED) -or- IN SERVICE PRESSURIZED ≤ 60 PSIG					
PROCEDURE NUMBER	**WELDING PROCESS**	**FILLER MATERIAL**	**PIPE/FITTING O.D. DIAMETER RANGE[1]**	**PIPE/FITTING WALL THICKNESS RANGE[1]**	**MATERIAL GRADE[2]**
F2	SMAW	E6010	< 2.375”	0.188” ≤ 0.750”	Gr. B
F3	SMAW	E6010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F4	SMAW	E6010	< 2.375”	< 0.188"	Gr. B ≤ X42
F5	SMAW	E6010	< 2.375”	0.188” ≤ 0.750”	Gr. B ≤ X42
F6	SMAW	E6010	< 2.375”	< 0.188"	X46 ≤ X52
F7	SMAW	E6010	< 2.375”	0.188” ≤ 0.750”	X46 ≤ X52
F9	SMAW	E6010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52
F12	SMAW	E8010	< 2.375”	< 0.188"	Gr. B ≤ X42
F13	SMAW	E8010	< 2.375”	0.188” ≤ 0.750”	Gr. B ≤ X42
F14	SMAW	E8010	< 2.375”	< 0.188"	X46 ≤ X52
F15	SMAW	E8010	< 2.375”	0.188” ≤ 0.750”	X46 ≤ X52
F17	SMAW	E8010	< 2.375”	0.188” ≤ 0.750”	X65
F19	SMAW	E8010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F21	SMAW	E8010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52
F23	SMAW	E8010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X65
FILLET WELDS - PRODUCTION (NON-PRESSURIZED) -or- IN SERVICE ALL PRESSURES, ALL %SMYS					
PROCEDURE NUMBER	**WELDING PROCESS**	**FILLER MATERIAL**	**PIPE/FITTING O.D. DIAMETER RANGE[1]**	**PIPE/FITTING WALL THICKNESS RANGE[1]**	**MATERIAL GRADE[2]**
F41	GMAW	ER-70-S-6	< 2.375”	< 0.188"	Gr. B ≤ X42
F42	GMAW	ER-70-S-6	< 2.375”	0.188” ≤ 0.750”	Gr. B ≤ X42
F43	GMAW	ER-70-S-6	2.375” ≤ 12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F45	GMAW	ER-70-S-6	< 2.375”	< 0.188"	X46 ≤ X52
F46	GMAW	ER-70-S-6	< 2.375”	0.188” ≤ 0.750”	X46 ≤ X52
F47	GMAW	ER-70-S-6	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52
F49	GMAW	ER-70-S-6	< 2.375”	0.188” ≤ 0.750”	X65
F61	SMAW	E7018	< 2.375”	0.188” ≤ 0.750”	Gr. B ≤ X42
F62	SMAW	E7018	2.375” ≤ 12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F64	SMAW	E7018	< 2.375”	0.188” ≤ 0.750”	X46 ≤ X52
F65	SMAW	E7018	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52

Table continued on following page

APPENDIX A - WELD PROCEDURE INDEX CONTINUED

REPAIR SLEEVE - PRODUCTION (NON-PRESSURIZED) -or- IN SERVICE PRESSURIZED ≤ 60 PSIG					
PROCEDURE NUMBER	**WELDING PROCESS**	**FILLER MATERIAL**	**PIPE/FITTING O.D. DIAMETER RANGE[1]**	**PIPE/FITTING WALL THICKNESS RANGE[1]**	**MATERIAL GRADE[2]**
F24	SMAW	E6010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F25	SMAW	E6010	>12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F28	SMAW	E6010	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52
F29	SMAW	E6010	>12.750”	0.188” ≤ 0.750”	X46 ≤ X52

REPAIR SLEEVE - PRODUCTION (NON-PRESSURIZED) -or- IN SERVICE ALL PRESSURES, ALL %SMYS					
PROCEDURE NUMBER	**WELDING PROCESS**	**FILLER MATERIAL**	**PIPE/FITTING O.D. DIAMETER RANGE[1]**	**PIPE/FITTING WALL THICKNESS RANGE[1]**	**MATERIAL GRADE[2]**
F31	SMAW	E7018	2.375” ≤ 12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F32	SMAW	E7018	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52
F33	SMAW	E7018	>12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F34	SMAW	E7018	>12.750”	0.188” ≤ 0.750”	X46 ≤ X52
F44	GMAW	ER-70-S-6	2.375” ≤ 12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F48	GMAW	ER-70-S-6	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X46 ≤ X52
F51	GMAW	ER-70-S-6	2.375” ≤ 12.750”	0.188” ≤ 0.750”	X65
F53	GMAW	ER-70-S-6	>12.750”	0.188” ≤ 0.750”	Gr. B ≤ X42
F54	GMAW	ER-70-S-6	>12.750”	0.188” ≤ 0.750”	X46 ≤ X52

Full encirclement fitting, “barrel”, and “can” installation requirements: The longitudinal seam weld shall be done by following the appropriate butt weld procedure applicable to the material specifications for the fitting, barrel or can. The fillet weld shall be done by following the appropriate fillet weld procedure applicable to the material specifications for the fitting, barrel or can and not the gas carrying pipe.

[1] For fillet welds, pipe/fitting O.D. and wall thickness ranges are referring to the branch pipe or fitting specifications.

[2] Select welding procedure based on the higher of the two material grades. If welding on intermediate pressure pipe and the grade is unknown, select the welding procedure for material grade X46 ≤ X52. If welding on high pressure pipe and the grade is unknown, contact Gas Engineering for assistance determining the correct welding procedure.

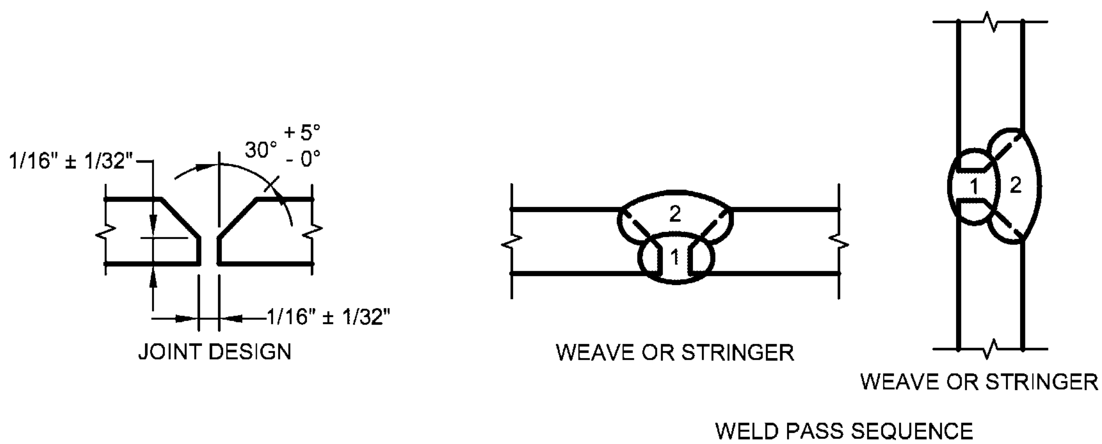
.

PROCEDURE NUMBER: B1
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375” O.D. / < 0.188” W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS			
PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	3/32”	E6010	50-100	18-32	4-14	N/A
2	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, All Passes)	50-100	18-32	4-14
1/8” (E6010, All Passes)	60-130	18-38	4-15

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 9-6-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

PROCEDURE NUMBER: B3

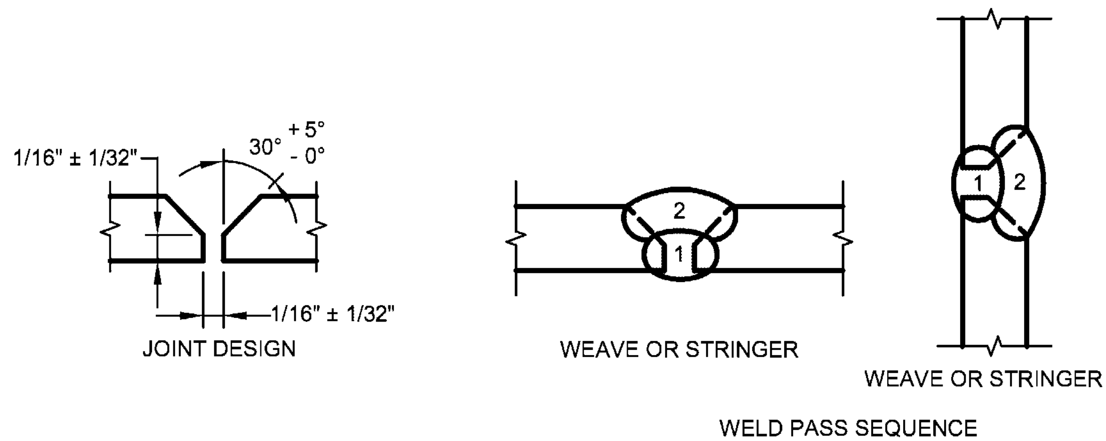
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / < 0.188” W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	3/32”	E6010	50-100	18-32	4-14	N/A
2	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, All Passes)	50-100	18-32	4-14
1/8” (E6010, All Passes)	60-130	18-38	4-15

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature]	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

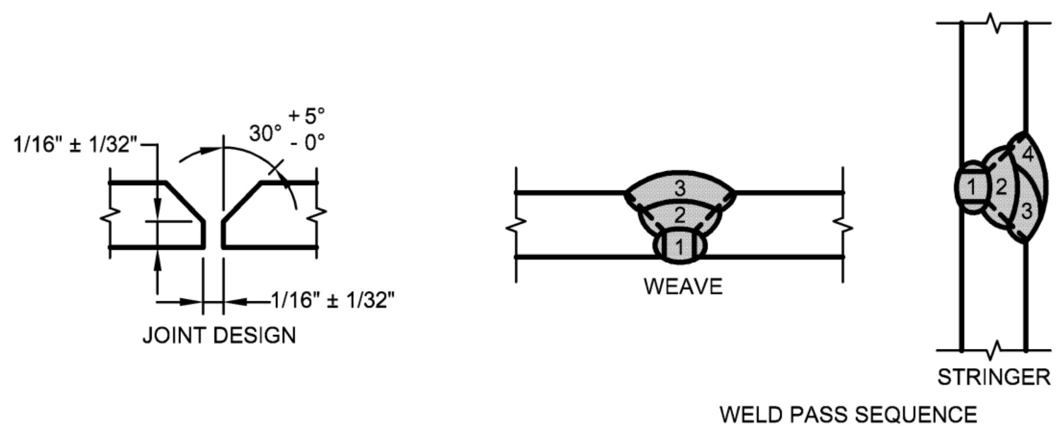
PROCEDURE NUMBER: B4
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
5/32” (E6010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A. Webb	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192**.**

AVISTA Utilities

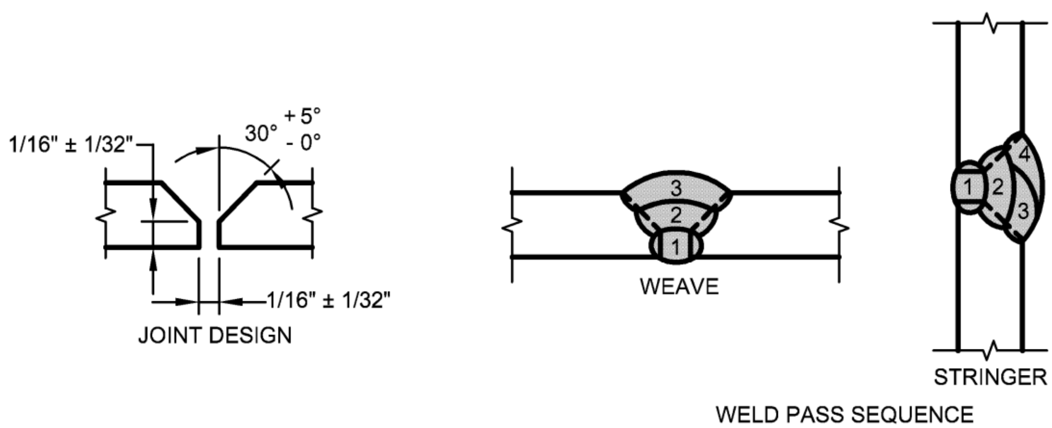
PROCEDURE NUMBER: B5
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	> 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	Two Preferred, One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
3	SMAW	5/32”	E6010	100-180	18-40	4-16	N/A
Rem.*	SMAW	3/16”	E6010	140-225	28-36	5-18	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
1/8” (E6010, All Passes)	60-130	18-38	4-15
5/32” (E6010, Pass 2 – Remaining)	100-180	18-40	4-16
3/16” (E6010, Pass 3 – Remaining)	140-225	28-36	5-18

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffry a W[illegible] | Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

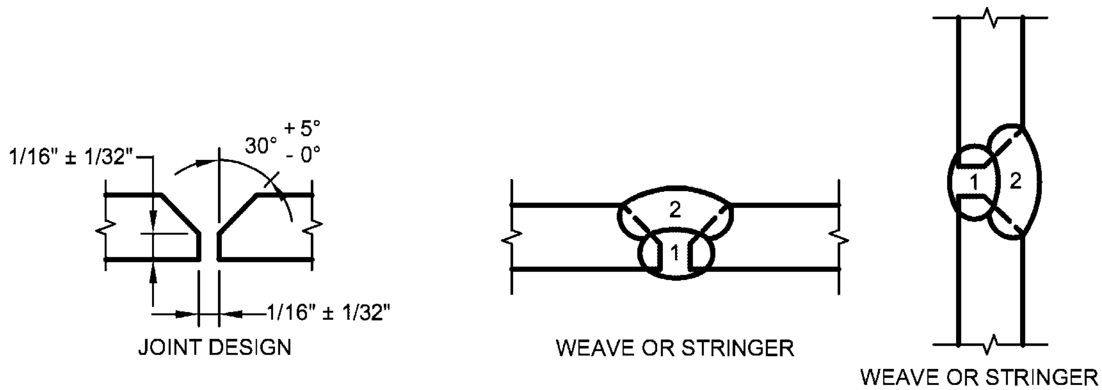
AVISTA Utilities

PROCEDURE NUMBER: B6
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / < 0.188” W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS			
PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELD PASS SEQUENCE

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	3/32”	E6010	50-100	18-32	4-14	N/A
2	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, All Passes)	50-100	18-32	4-14
1/8” (E6010, All Passes)	60-130	18-38	4-15

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature]	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: B7
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)

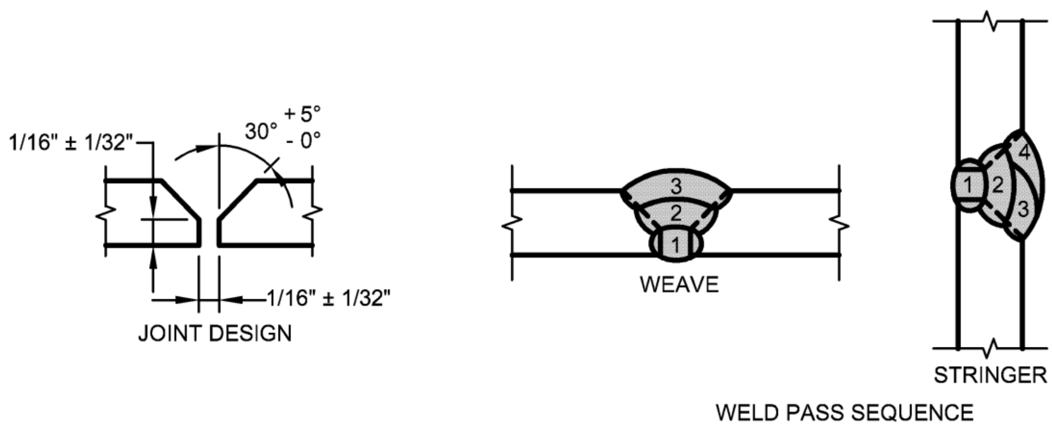
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
5/32” (E6010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: B8
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)

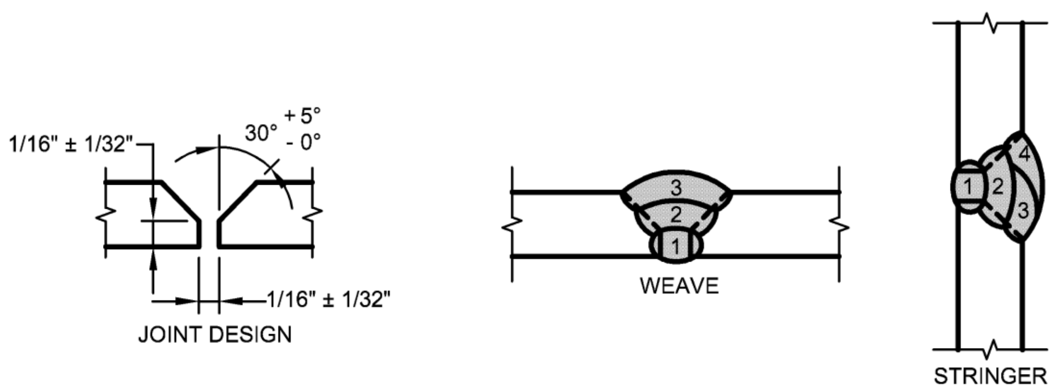
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	> 12.750" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	Two Preferred, One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELD PASS SEQUENCE

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
3	SMAW	5/32"	E6010	100-180	18-40	4-16	N/A
Rem.*	SMAW	3/16"	E6010	140-225	28-36	5-18	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
1/8" (E6010, All Passes)	60-130	18-38	4-15
5/32" (E6010, Pass 2 – Remaining)	100-180	18-40	4-16
3/16" (E6010, Pass 3 – Remaining)	140-225	28-36	5-18

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

PROCEDURE NUMBER: B9

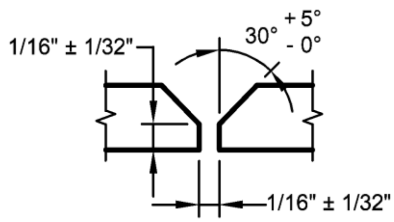
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X65
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E7018 Hot and Filler Passes

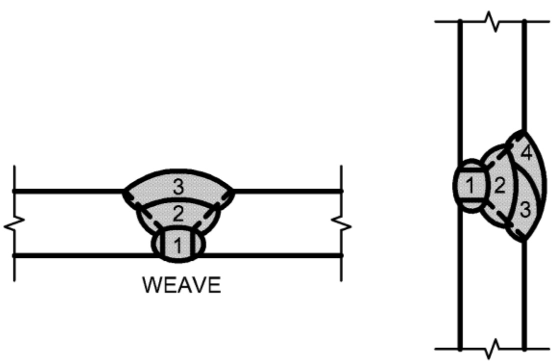
PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	E6010 Downhill E7018 Uphill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum (preheat pipe and fitting)		

JOINT AND WELD DESIGN



JOINT DESIGN



WELD PASS SEQUENCE

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
3	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
Rem.*	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
1/8” (E7018, Pass 2 – Remaining)	90-160	20-40	4-12
5/32” (E7018, Pass 2 – Remaining)	110-200	20-40	4-14

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeff a Wlt	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

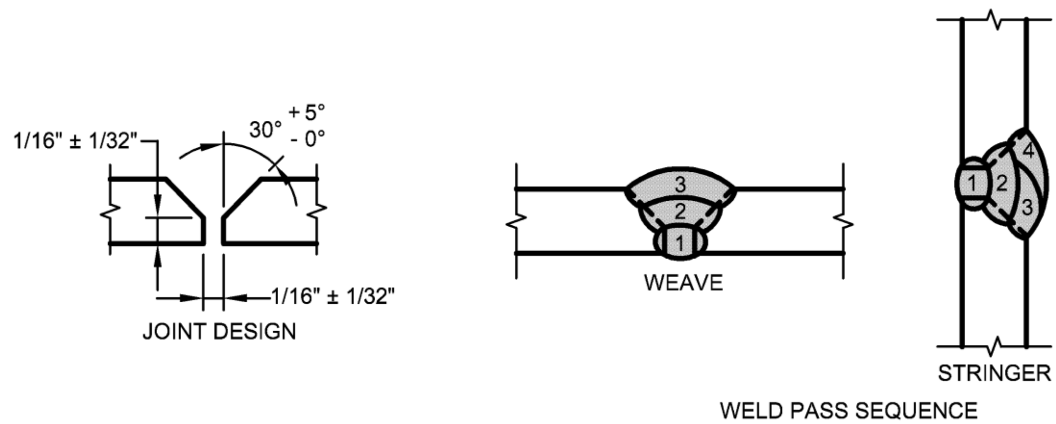
PROCEDURE NUMBER: B17
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
5/32” (E8010, Pass 2 – Remaining)	100-180	18-40	4-16
3/16” (E8010, Pass 2 – Remaining)	110-225	18-40	5-18

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 5-29-20

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

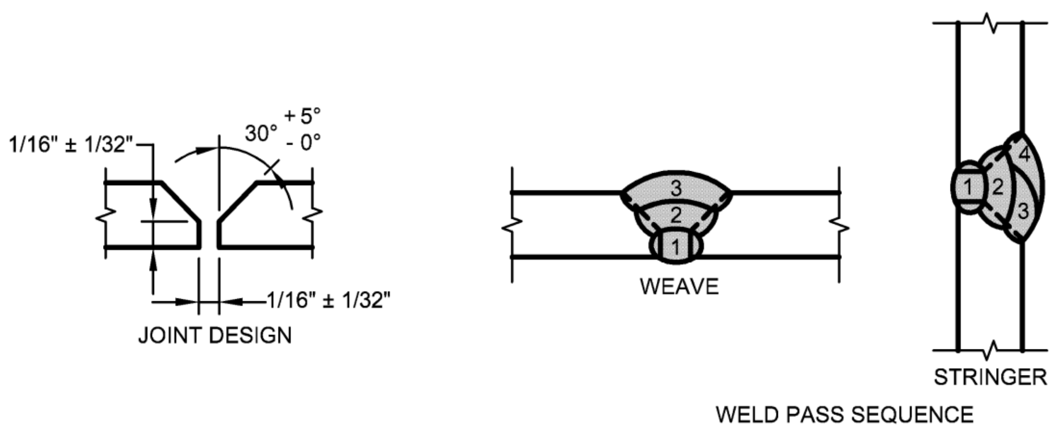
AVISTA Utilities

PROCEDURE NUMBER: B19
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X65
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS			
PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
5/32” (E8010, Pass 2 – Remaining)	100-180	18-40	4-16
3/16” (E8010, Pass 2 – Remaining)	110-225	18-40	5-18

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 8-25-20

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: B21
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)

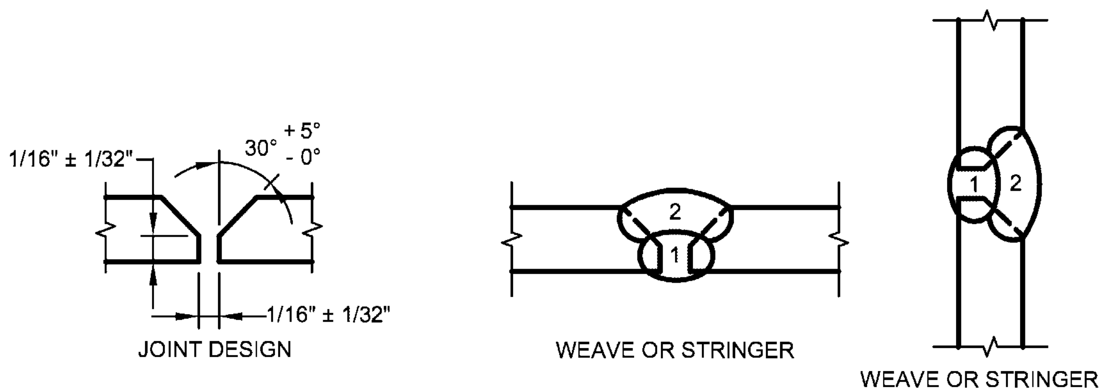
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	Gr. B
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375” O.D. / < 0.188” W.T.
FILLER MATERIAL:	AWS 5.18 ER-70-S-6 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELD PASS SEQUENCE

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-17	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-17	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-17	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffy a Wll	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

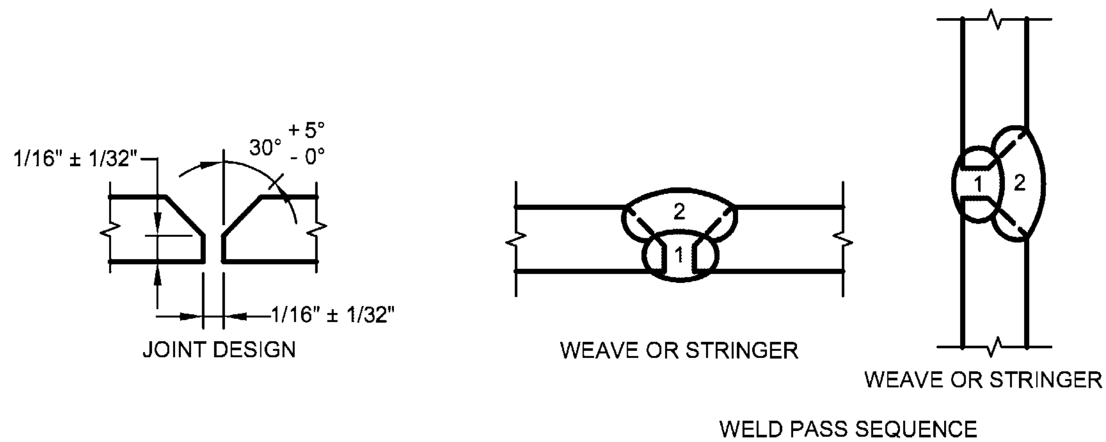
PROCEDURE NUMBER: B23
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Grd. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / < 0.188” W.T.
FILLER MATERIAL:	AWS 5.18 ER-70-S-6 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem*	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: B24
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)

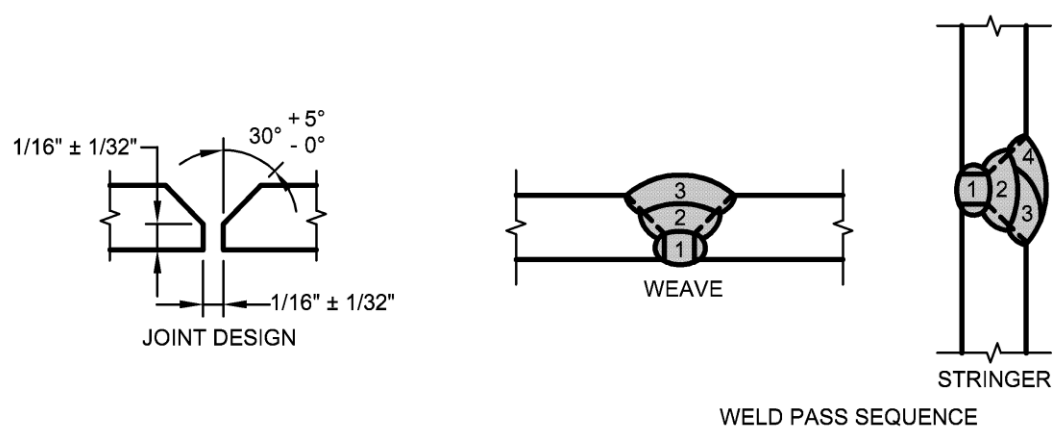
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS 5.18, ER-70-S-2,6 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
3	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey a Webb	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

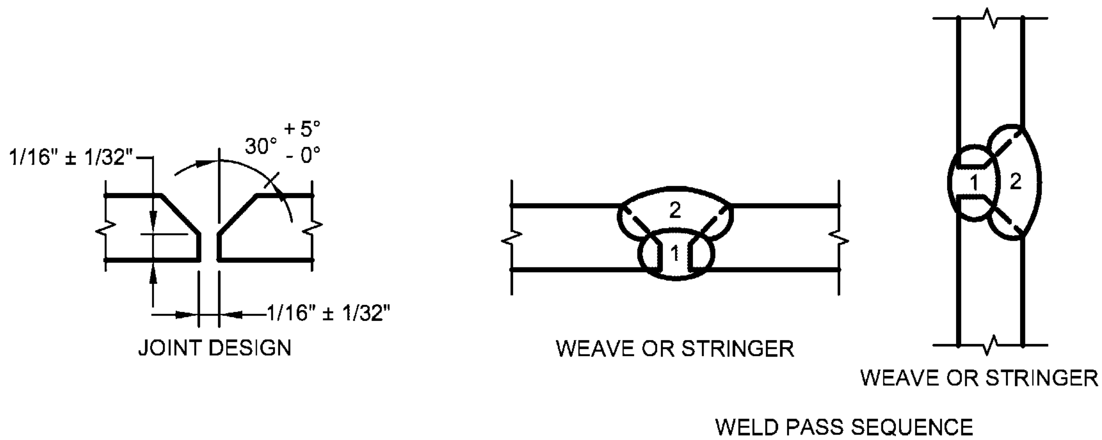
PROCEDURE NUMBER: B26
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375" ≤ 12.750" O.D. / < 0.188" W.T.
FILLER MATERIAL:	AWS 5.18 ER-70-S-6 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey a Wall	Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

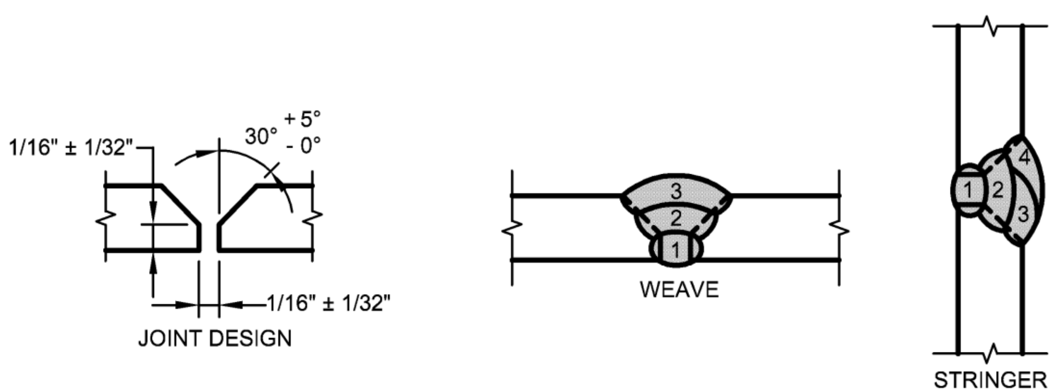
PROCEDURE NUMBER: B27
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS 5.18, ER-70-S-2,6 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELD PASS SEQUENCE

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
3	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature]	Date: 9-12-19

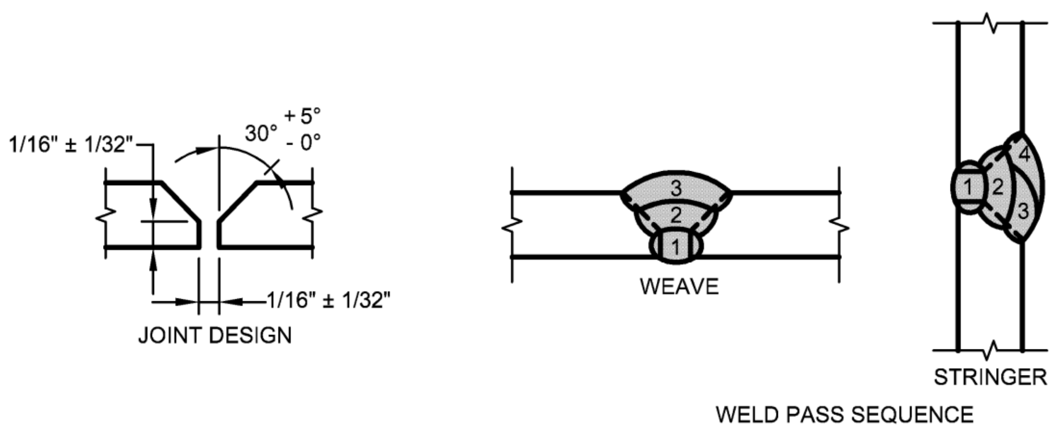
This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: B29
Weld Category: Production, Non Pressurized

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)		
PIPE AND FILLER MATERIAL REQUIREMENTS			
PIPE GRADES QUALIFIED:	X65		
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375" ≤ 12.750" O.D. / 0.188" ≤ 0.750" W.T.		
FILLER MATERIAL:	AWS 5.18, ER-70-S-2,6 Root, Hot and Filler Passes		
PRODUCTION WELDING CONDITIONS			
PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Lineup clamp should be used for welds in the field. If clamp is used it shall be kept in place until root bead is at least 50% complete.		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOWRATE
1	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
3	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature] Date: 9-12-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

Avista Utilities

PROCEDURE NUMBER: F2

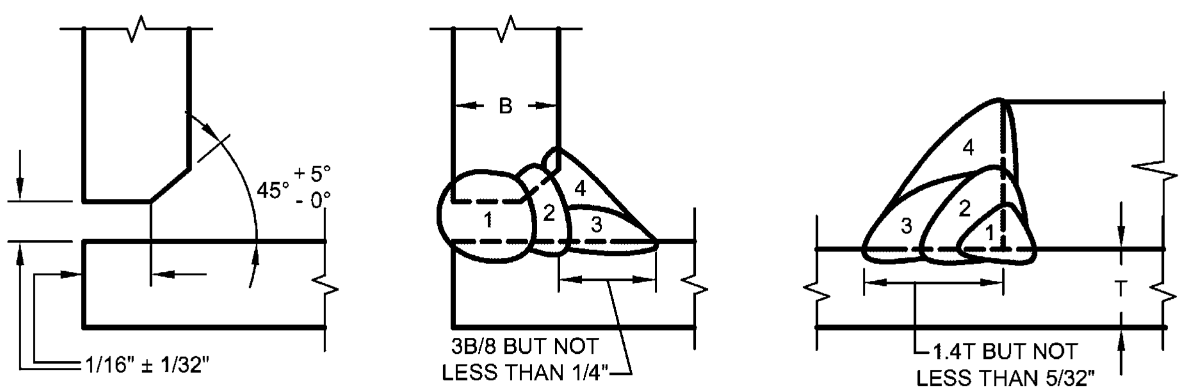
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	3/32"	E6010	50-100	18-32	4-14	N/A
2	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
3	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32" (E6010, All passes)	50-100	18-32	4-14
1/8" (E6010, All passes)	60-130	18-38	4-15
5/32" (E6010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F3

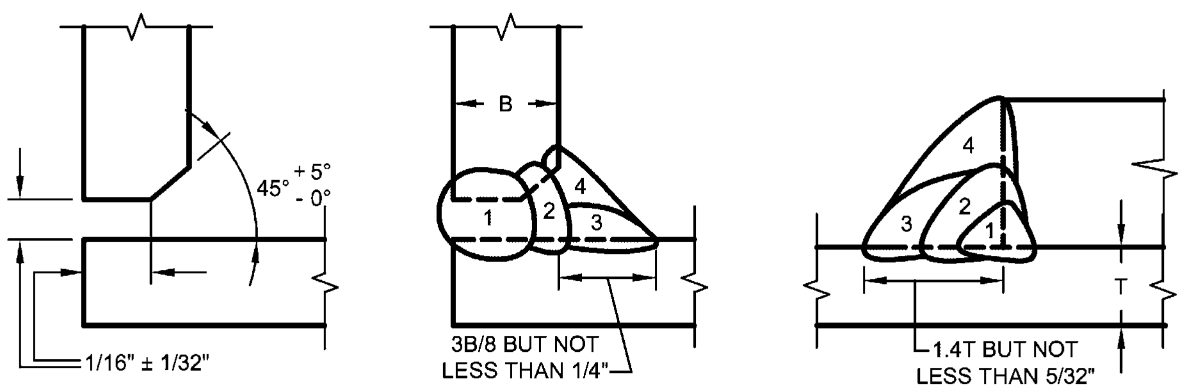
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS 5.1, E6010 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, All passes)	50-100	18-32	4-14
5/32” (E6010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F4

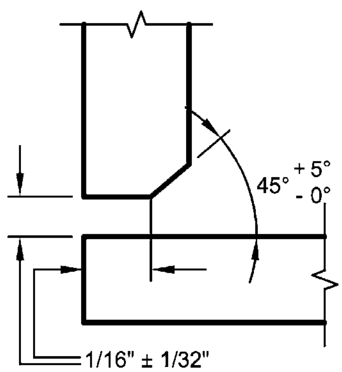
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / < 0.188" W.T.
FILLER MATERIAL:	AWS 5.1 - E6010 Root, Hot, and Filler Passes

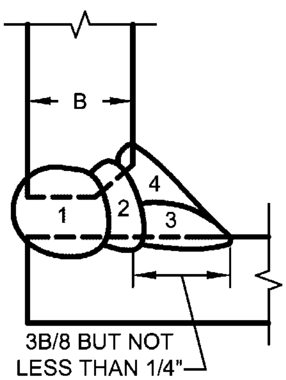
PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum)		

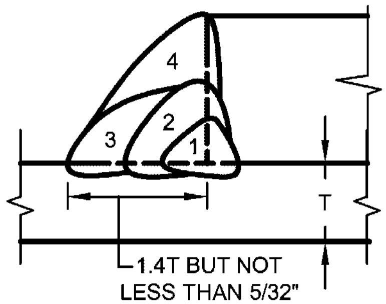
JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH)



WELD PASS SEQUENCE (BRANCH)



WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	3/32"	E6010	50-100	18-32	4-14	N/A
2	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
3	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32" (E6010, All passes)	50-100	18-32	4-14
1/8" (E6010, All passes)	60-130	18-38	4-15

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffry A. Webb	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F5

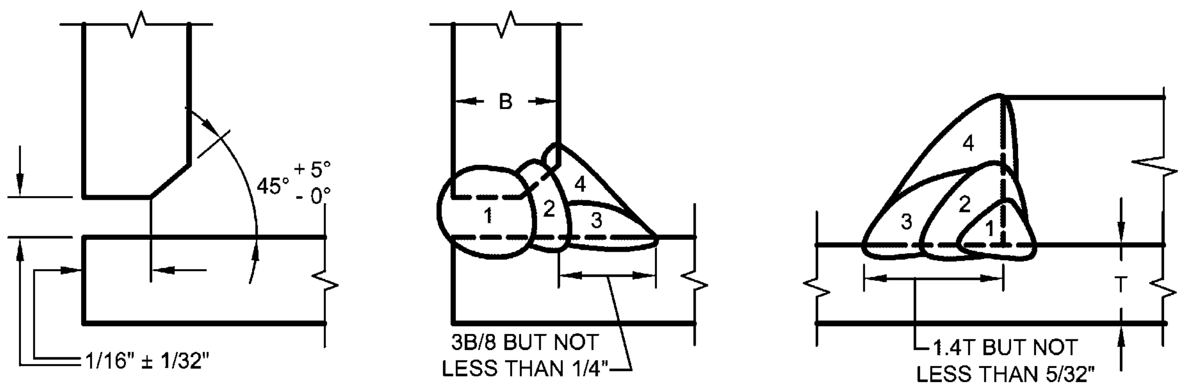
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS 5.1 - E6010 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, All passes)	50-100	18-32	4-14

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F6

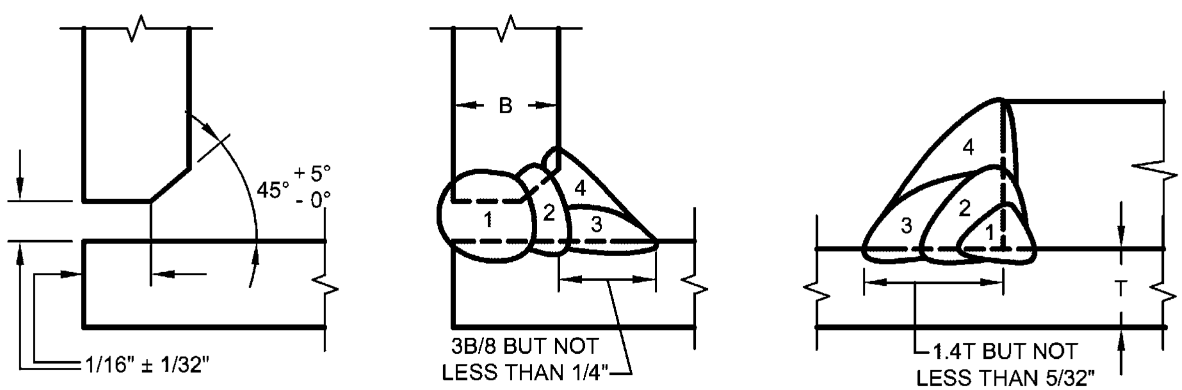
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / < 0.188" W.T.
FILLER MATERIAL:	AWS 5.1 - E6010 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELCTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	3/32"	E6010	50-100	18-32	4-14	N/A
2	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
3	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32" (E6010, All passes)	50-100	18-32	4-14
1/8" (E6010, All passes)	60-130	18-38	4-15

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 1-21-19

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F7

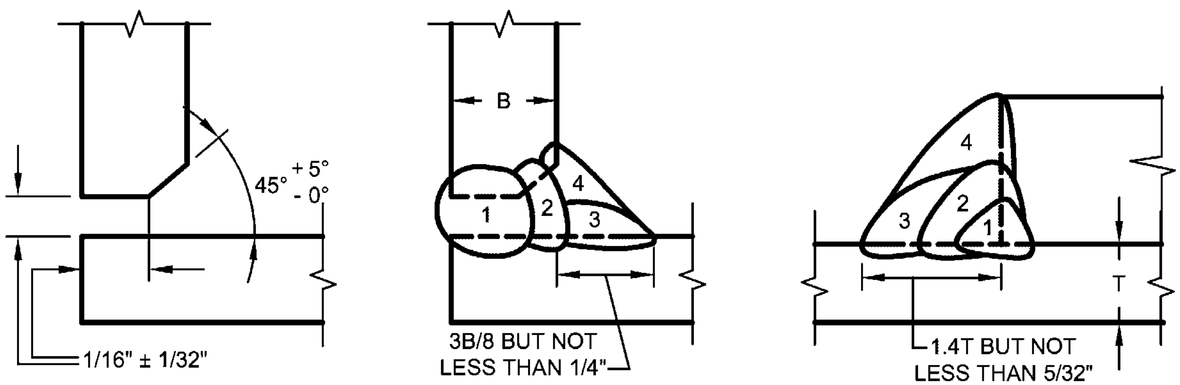
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS 5.1 - E6010 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	3/32"	E6010	50-100	18-32	4-14	N/A
2	SMAW	3/32"	E6010	50-100	18-32	4-14	N/A
3	SMAW	3/32"	E6010	50-100	18-32	4-14	N/A
Rem.*	SMAW	3/32"	E6010	50-100	18-32	4-14	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
1/8" (E6010, All passes)	60-130	18-38	4-15

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey a Wall	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F9
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)

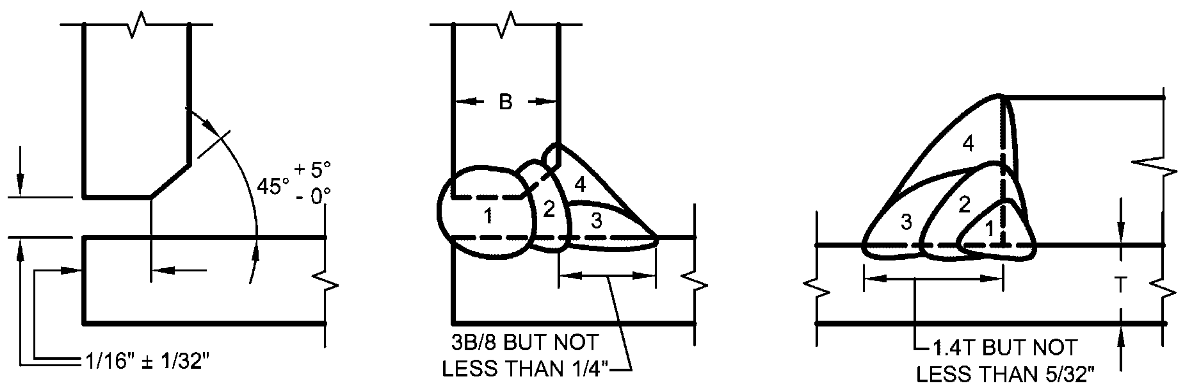
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS 5.1, E6010 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, All passes)	50-100	18-32	4-14
5/32” (E6010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature]	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

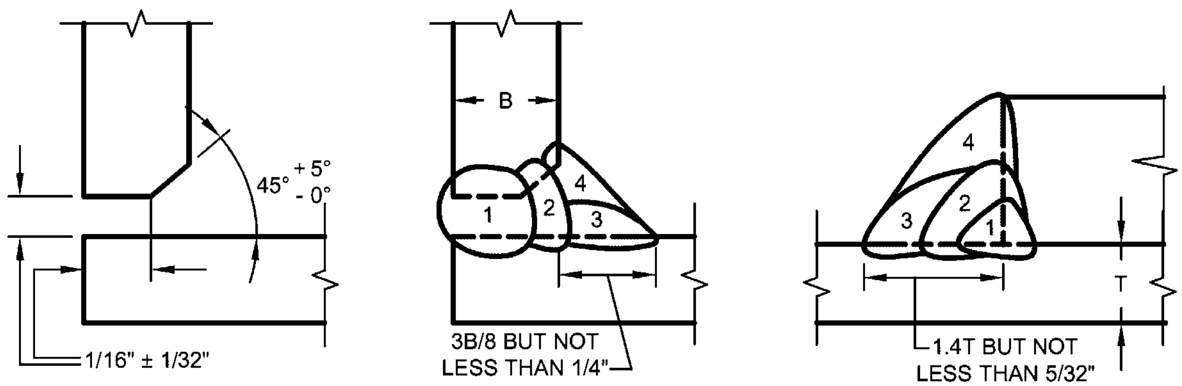
AVISTA Utilities

PROCEDURE NUMBER: F12

Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)		
PIPE AND FILLER MATERIAL REQUIREMENTS			
PIPE GRADES QUALIFIED:	Gr. B ≤ X42		
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375” O.D. / < 0.188” W.T.		
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes		
PRODUCTION WELDING CONDITIONS			
PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	3/32”	E6010	50-100	18-32	4-14	N/A
2	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
1/8” (E6010, Pass 1)	60-130	18-38	4-15
3/32” (E8010, Pass 2 – Remaining)	50-100	18-32	4-14
5/32” (E8010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffy a Webb — Date: 11-1-21

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F13

Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)

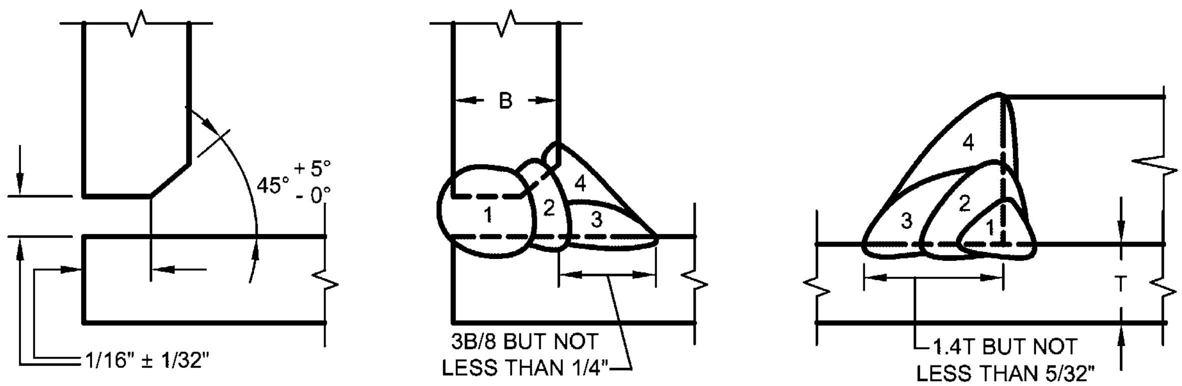
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8"	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8"	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8"	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32" (E6010, Pass 1)	50-100	18-32	4-14
3/32" (E8010, Pass 2 – Remaining)	50-100	18-32	4-14
5/32" (E8010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffy a Wel	Date: 11-1-21

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F14
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)

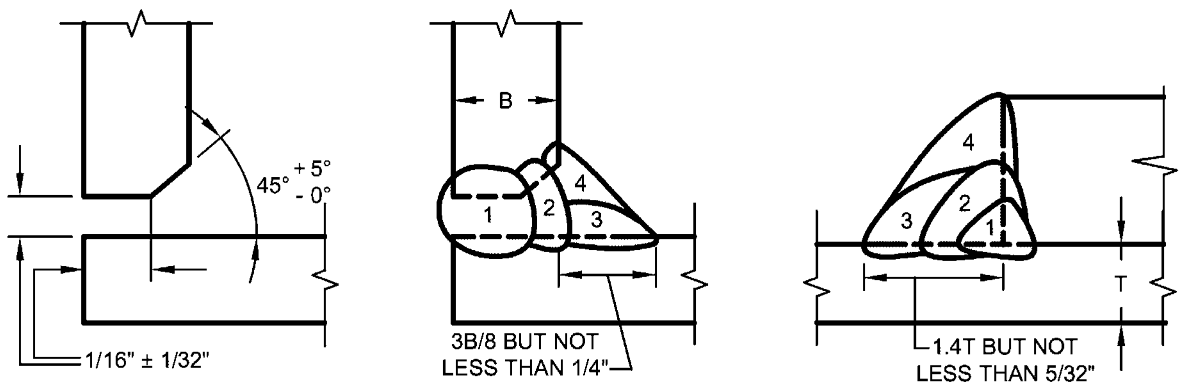
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / < 0.188" W.T.
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	3/32"	E6010	50-100	18-32	4-14	N/A
2	SMAW	1/8"	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8"	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8"	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
1/8" (E6010, Pass 1)	60-130	18-38	4-15
3/32" (E8010, Pass 2 – Remaining)	50-100	18-32	4-14
5/32" (E8010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey a Webb	Date: 11-1-21

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F15

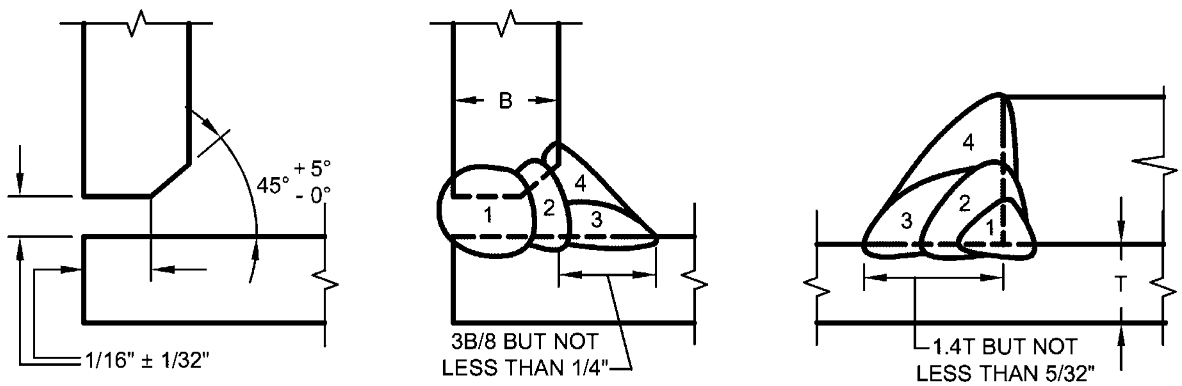
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
3/32” (E8010, Pass 2 – Remaining)	50-100	18-32	4-14
5/32” (E8010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 11-1-21

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F17

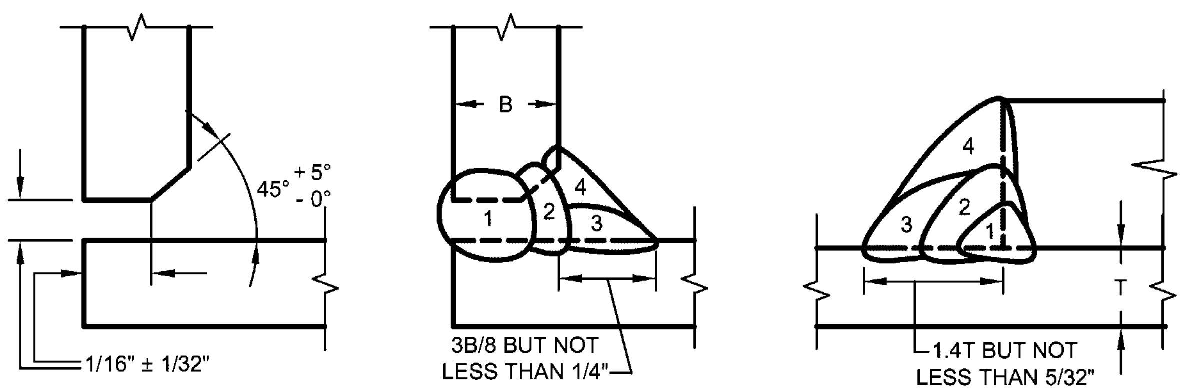
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X65
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8"	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8"	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8"	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32" (E6010, Pass 1)	50-100	18-32	4-14
3/32" (E8010, Pass 2 – Remaining)	50-100	18-32	4-14
5/32" (E8010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: *Jeffy A Webb*	Date: 11-1-21

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

PROCEDURE NUMBER: F19

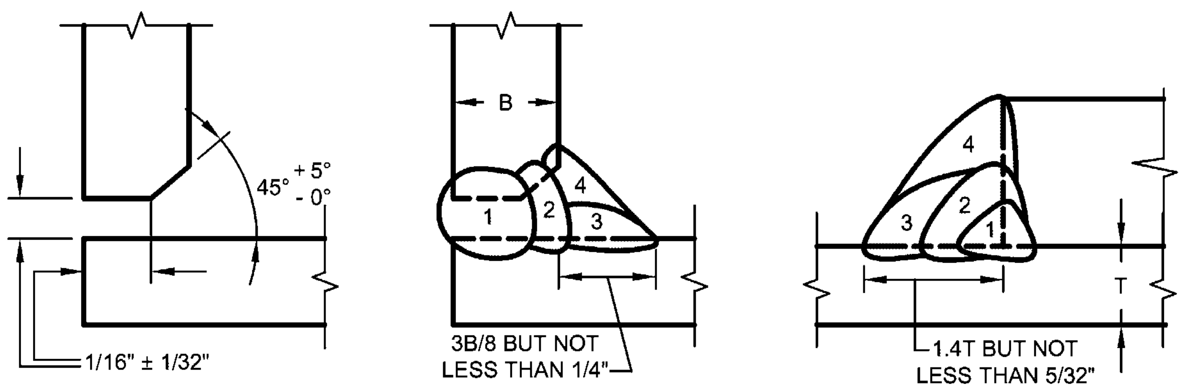
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
3/32” (E8010, Pass 2 – Remaining)	50-100	18-32	4-14
5/32” (E8010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeff a W[illegible]	Date: 11-1-21

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

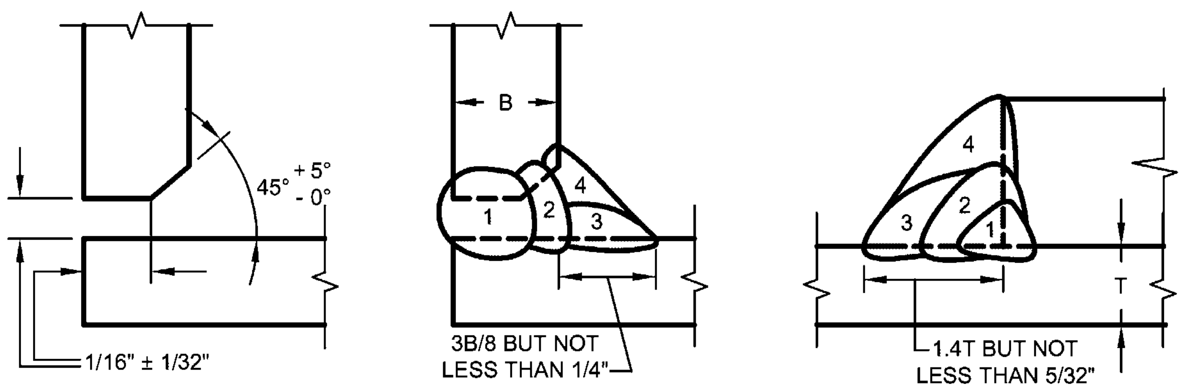
PROCEDURE NUMBER: F21

Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS			
PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
3/32” (E8010, Pass 2 – Remaining)	50-100	18-32	4-14
5/32” (E8010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 11-1-21

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F23

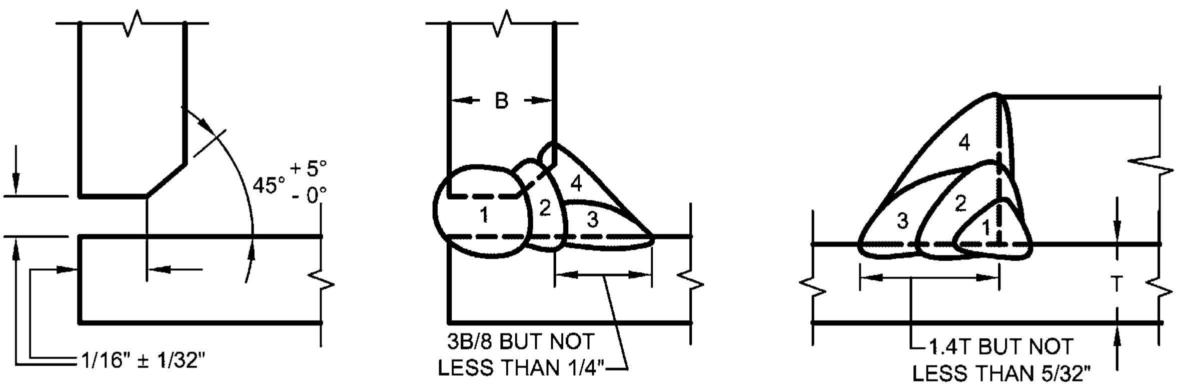
Weld Category: Production and In-Service, (Pressurized ≤ 60 PSIG)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X65
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E8010 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
3	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A
Rem.*	SMAW	1/8”	E8010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
3/32” (E8010, Pass 2 – Remaining)	50-100	18-32	4-14
5/32” (E8010, Pass 2 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 11-1-21

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F24

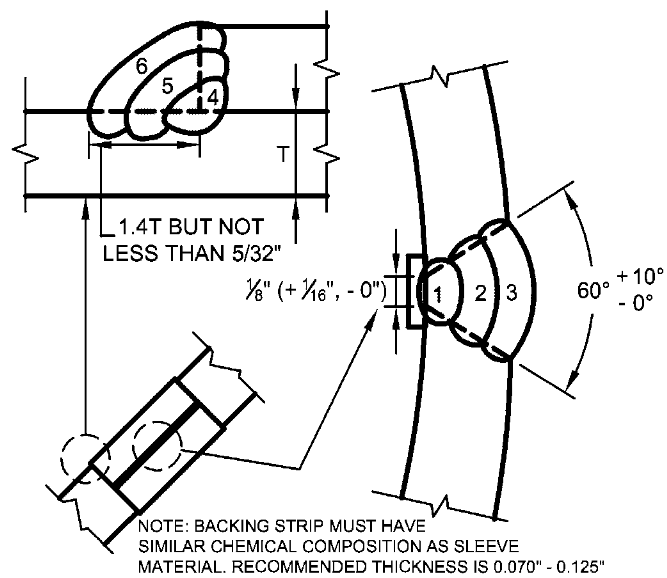
Weld Category: Production and In-Service (Pressurized ≤ 60 psig)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill for fillet and groove
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1,4	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2,5	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
3,6	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1,4)	50-100	18-32	4-14
5/32” (E6010, Pass 2,5 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

PROCEDURE NUMBER: F25

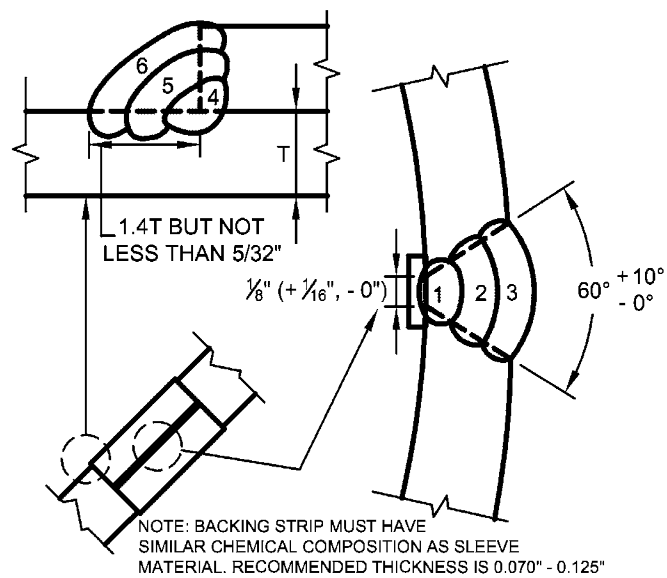
Weld Category: Production and In-Service (Pressurized ≤ 60 psig)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	> 12.750" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill for fillet and groove
NUMBER OF WELDERS:	Two Preferred, One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1,4	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
2,5	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
3,6	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
Rem*	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32" (E6010, Pass 1,4)	50-100	18-32	4-14
5/32" (E6010, Pass 2,5 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeff a Webb	Date: 9-5-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F28

Weld Category: Production and In-Service (Pressurized ≤ 60 psig)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)

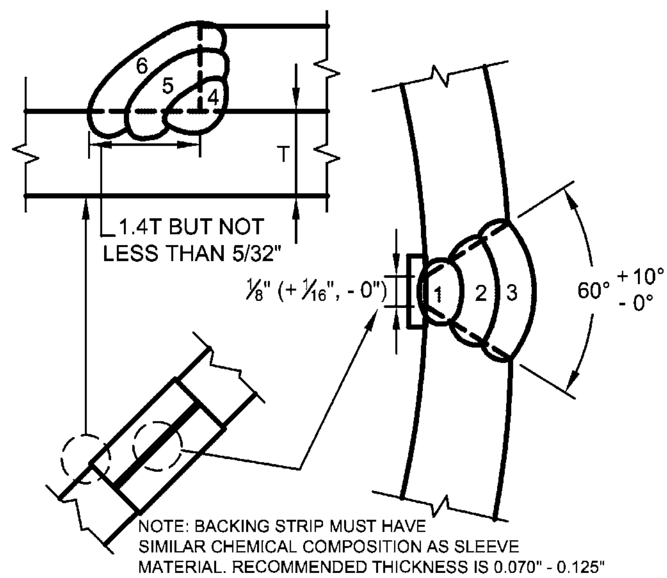
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill for fillet and groove
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1,4	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2,5	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
3,6	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
Rem*	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1,4)	50-100	18-32	4-14
5/32” (E6010, Pass 2,5 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F29

Weld Category: Production and In-Service (Pressurized ≤ 60 psig)

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)

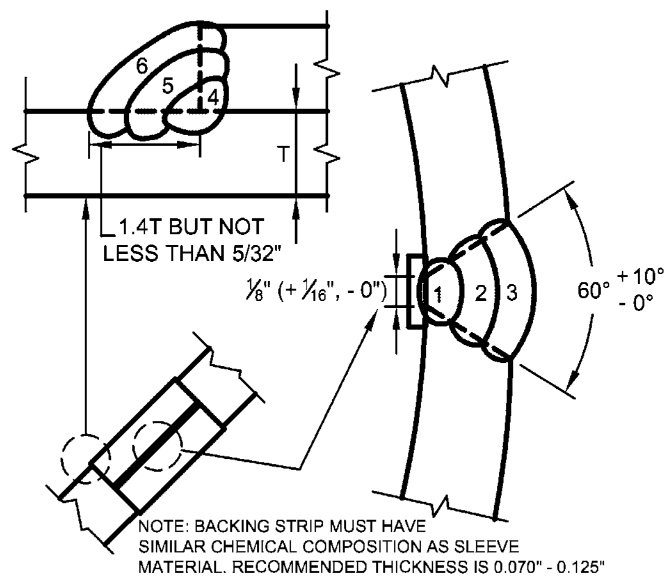
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	> 12.750" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS E6010 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill for fillet and groove
NUMBER OF WELDERS:	Two Preferred, One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	If ambient temperature above 40°F: No preheat required unless to remove moisture from pipe/fitting If ambient temperature 40°F and below: 200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1,4	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
2,5	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
3,6	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
Rem*	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32" (E6010, Pass 1,4)	50-100	18-32	4-14
5/32" (E6010, Pass 2,5 – Remaining)	100-180	18-40	4-16

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 9-5-18

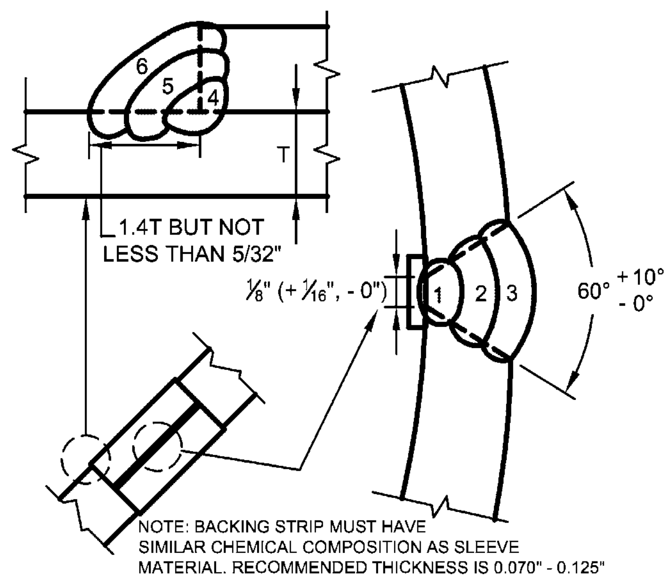
This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F31
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)		
PIPE AND FILLER MATERIAL REQUIREMENTS			
PIPE GRADES QUALIFIED:	Gr. B ≤ X42		
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375" ≤ 12.750" O.D. / 0.188" ≤ 0.750" W.T.		
FILLER MATERIAL:	AWS E6010 Root, E7018 Hot and Filler Passes		
PRODUCTION WELDING CONDITIONS			
PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	E6010 Downhill E7018 Uphill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1,4	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
2,5	SMAW	3/32"	E7018	70-110	20-35	2-10	N/A
3,6	SMAW	3/32"	E7018	70-110	20-35	2-10	N/A
Rem.*	SMAW	3/32"	E7018	70-110	20-35	2-10	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32" (E6010, Pass 1,4)	50-100	18-32	4-14
1/8" (E7018, Pass 2,5 - Remaining)	90-160	20-40	4-12

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A. Webb	Date: 3-23-17

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

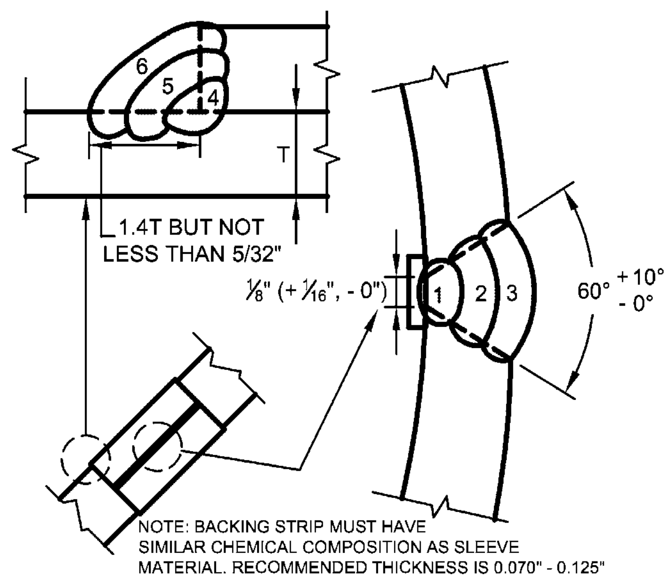
PROCEDURE NUMBER: F32
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E7018 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	E6010 Downhill E7018 Uphill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1,4	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2,5	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
3,6	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
Rem.*	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1,4)	50-100	18-32	4-14
1/8” (E7018, Pass 2,5 - Remaining)	90-160	20-40	4-12

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature]	Date: 3-23-17

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

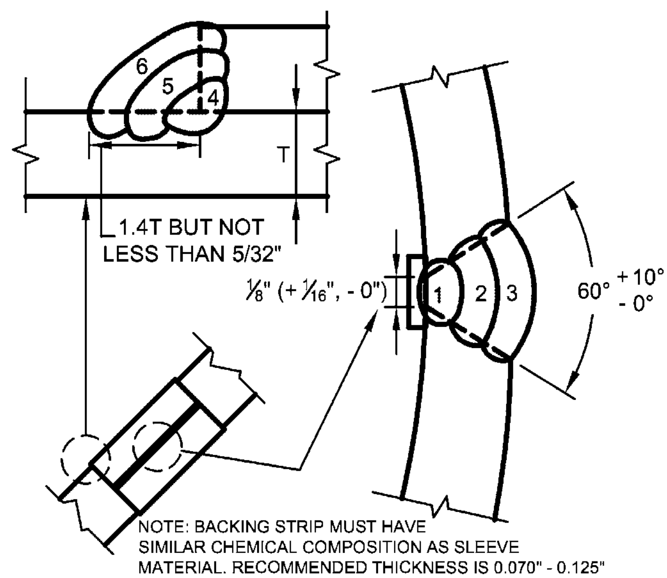
PROCEDURE NUMBER: F33
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	> 12.750" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS E6010 Root, E7018 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	E6010 Downhill E7018 Uphill
NUMBER OF WELDERS:	Two Preferred, One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1,4	SMAW	1/8"	E6010	60-130	18-38	4-15	N/A
2,5	SMAW	3/32"	E7018	70-110	20-35	2-10	N/A
3,6	SMAW	3/32"	E7018	70-110	20-35	2-10	N/A
Rem.*	SMAW	3/32"	E7018	70-110	20-35	2-10	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32" (E6010, Pass 1,4)	50-100	18-32	4-14
1/8" (E7018, Pass 2,5 - Remaining)	90-160	20-40	4-12

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature]	Date: 9-5-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

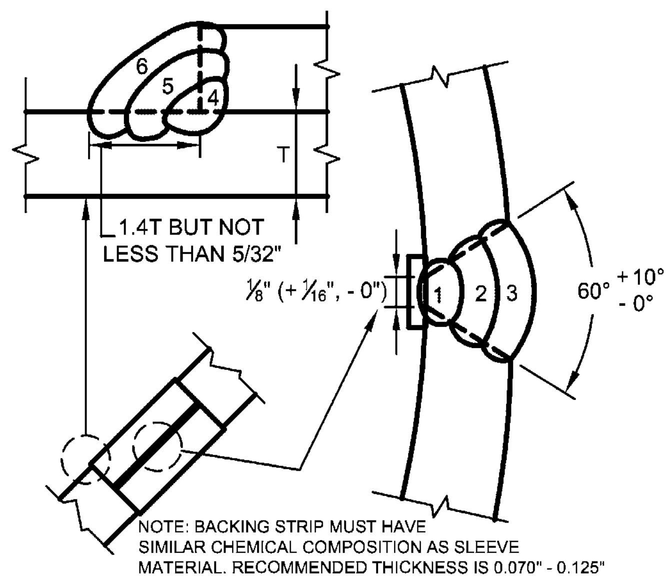
PROCEDURE NUMBER: F34
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	> 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E7018 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	E6010 Downhill E7018 Uphill
NUMBER OF WELDERS:	Two Preferred, One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1,4	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2,5	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
3,6	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
Rem.*	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1,4)	50-100	18-32	4-14
1/8” (E7018, Pass 2,5 - Remaining)	90-160	20-40	4-12

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 9-5-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

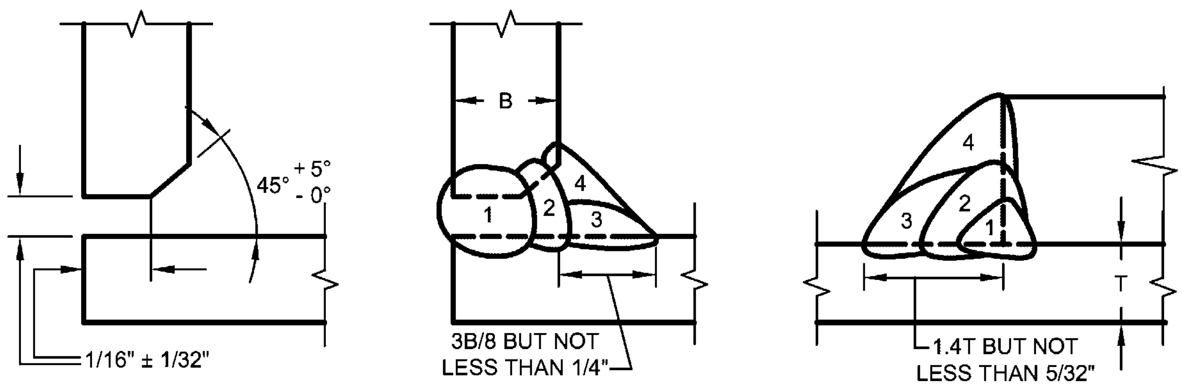
PROCEDURE NUMBER: F41
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375” O.D. / < 0.188” W.T.
FILLER MATERIAL:	AWS 5.18 – ER70-S-2,6* - Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 4-9-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

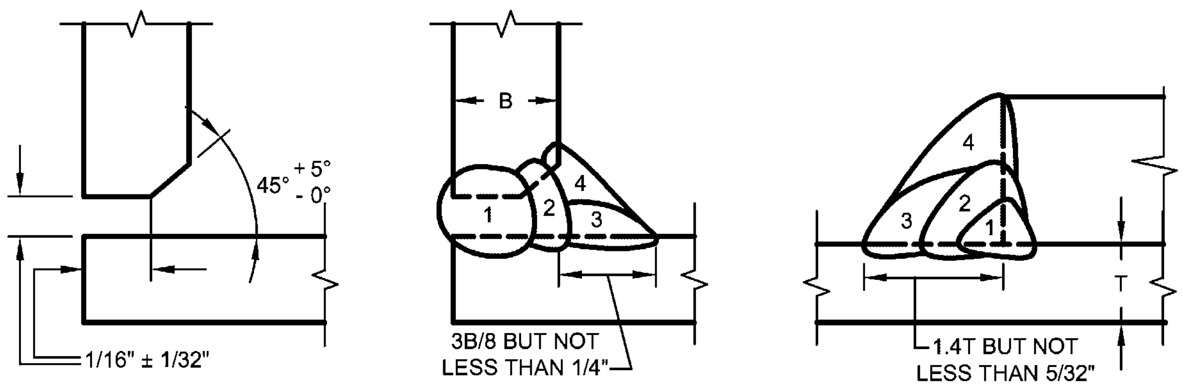
PROCEDURE NUMBER: F42
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS 5.18 - ER-70-S-2,6 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 4-9-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

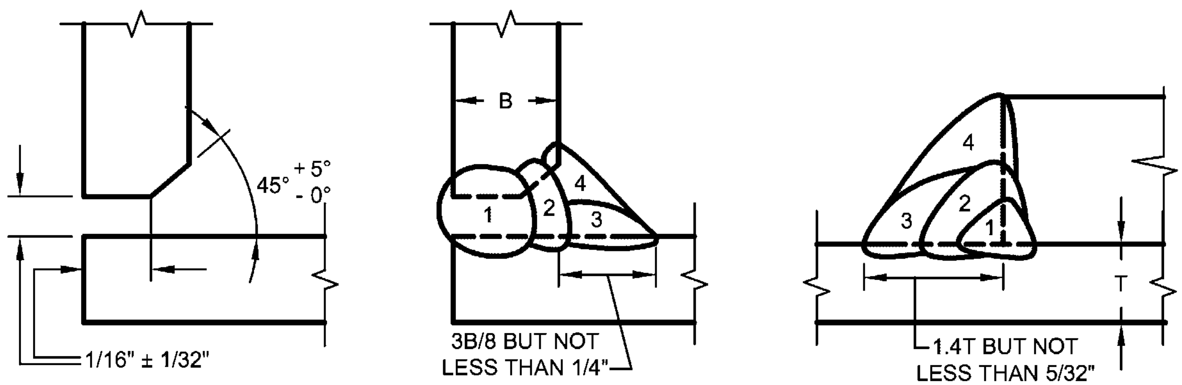
PROCEDURE NUMBER: F43
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375" ≤ 12.750" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS 5.18, ER-70-S-2,6 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature]	Date: 4-9-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

PROCEDURE NUMBER: F44
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)

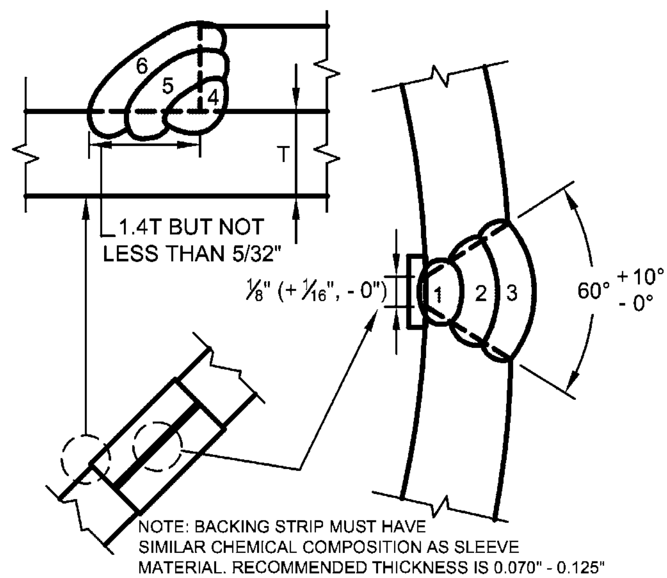
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS 5.18 ER-70-S-6 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill for fillet and groove
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1,4	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2,5	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
3,6	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem*	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

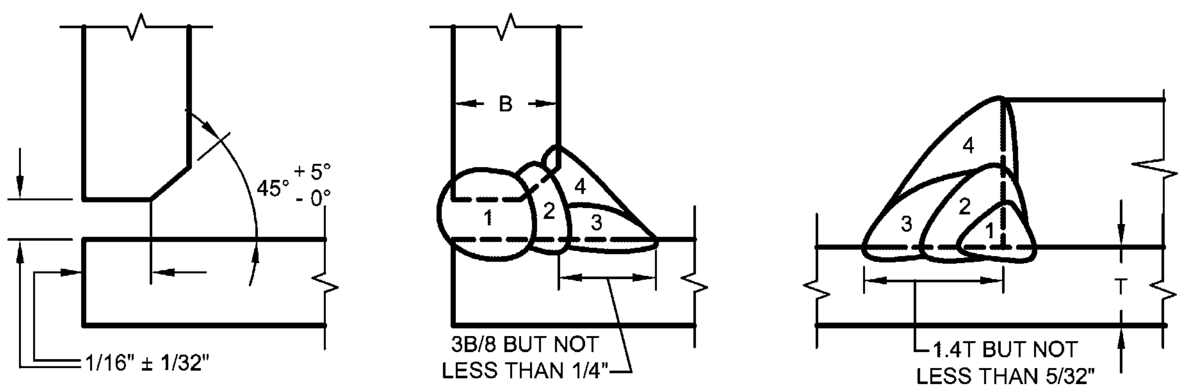
PROCEDURE NUMBER: F45
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / < 0.188" W.T.
FILLER MATERIAL:	AWS 5.18 - ER-70-S-2,6 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 4-9-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

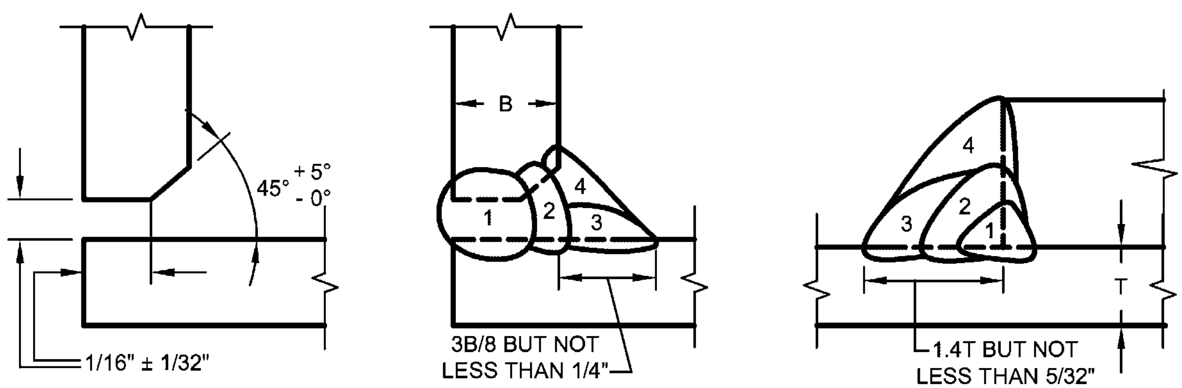
PROCEDURE NUMBER: F46
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS 5.18 - ER-70-S-2,6 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 4-9-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

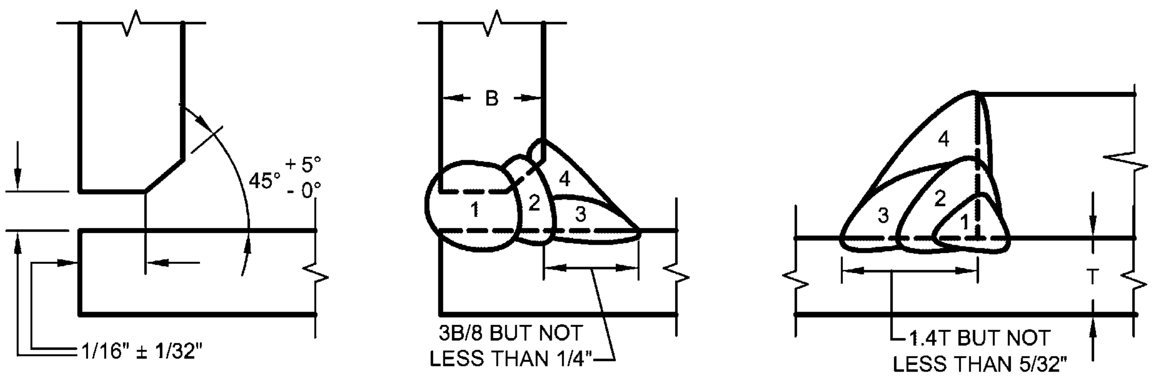
PROCEDURE NUMBER: F47
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS 5.18, ER-70-S-2,6 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP.:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 4-9-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

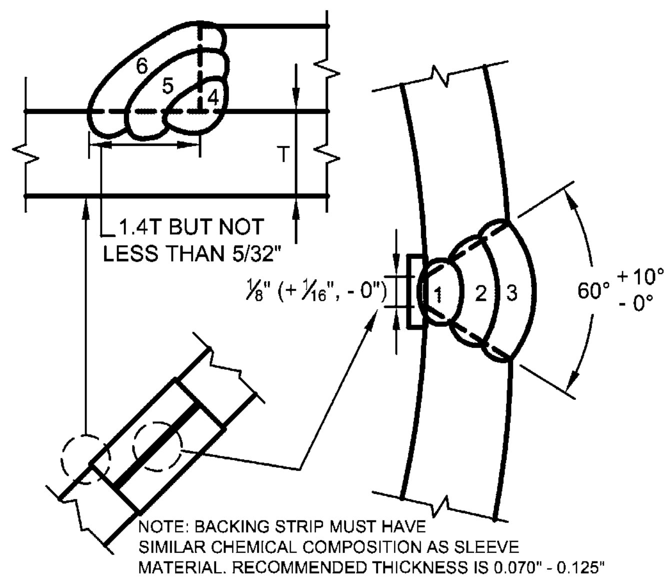
PROCEDURE NUMBER: F48
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375" ≤ 12.750" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS 5.18 ER-70-S-6 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill for fillet and groove
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1,4	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2,5	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
3,6	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem*	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature]	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F49
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc (GMAW)

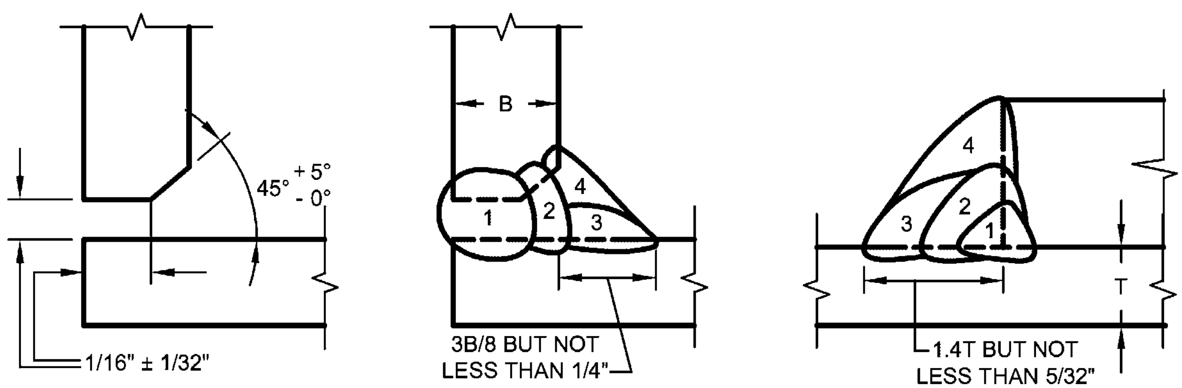
PIPE AND FILLER MATERIAL REQUIREMENTS

PIPE GRADES QUALIFIED:	X65
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS 5.18 - ER-70-S-2,6 Root, Hot, and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem.*	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey a Webb	Date: 4-9-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

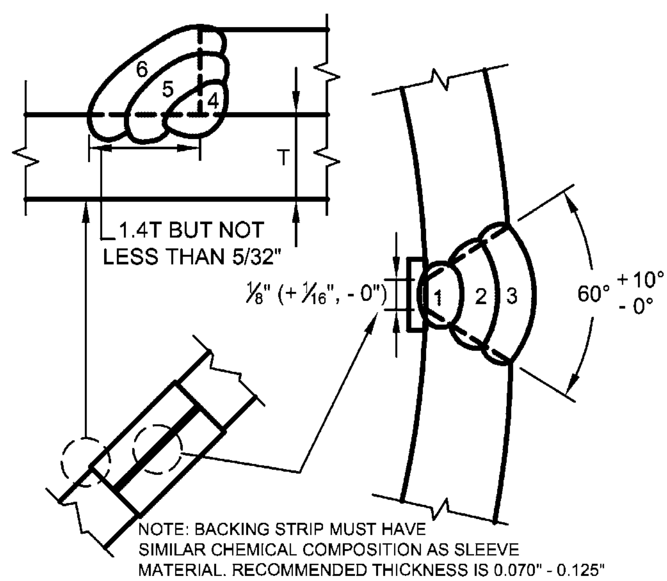
PROCEDURE NUMBER: F51
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X65
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS 5.18 ER-70-S-6 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill for fillet and groove
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F. Minimum - 400° F Maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1,4	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2,5	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
3,6	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem*	GMAW	0.03”	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

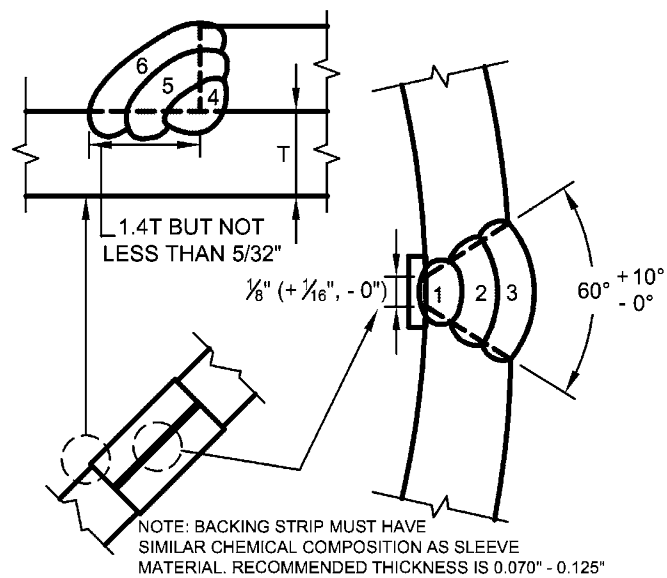
PROCEDURE NUMBER: F53
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	> 12.750" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS 5.18 ER-70-S-6 Root, Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill for fillet and groove
NUMBER OF WELDERS:	Two Proffered, One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1,4	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2,5	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
3,6	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem*	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

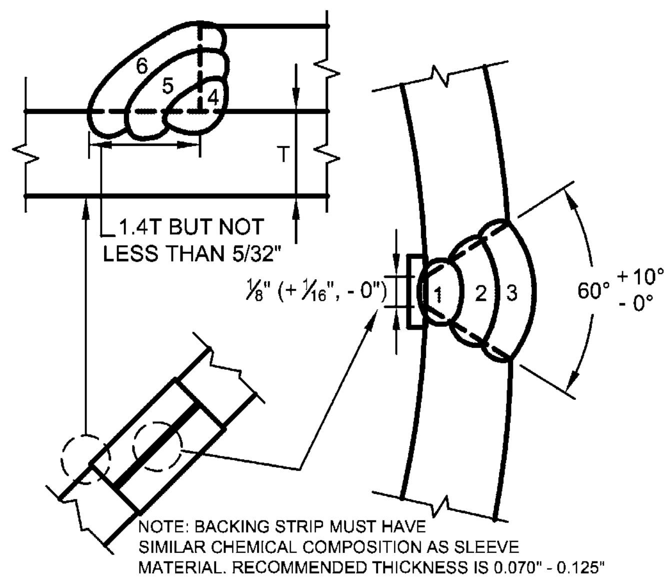
Approved: Jeffry a Wall | Date: 9-5-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F54
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Gas Metal Arc – (GMAW)		
PIPE AND FILLER MATERIAL REQUIREMENTS			
PIPE GRADES QUALIFIED:	X46 ≤ X52		
PIPE DIAMETER / W.T. RANGE QUALIFIED:	> 12.750" O.D. / 0.188" ≤ 0.750" W.T.		
FILLER MATERIAL:	AWS 5.18 ER-70-S-6 Root, Hot and Filler Passes		
PRODUCTION WELDING CONDITIONS			
PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	Downhill for fillet and groove
NUMBER OF WELDERS:	Two Preferred, One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	Jack and Chain or Similar		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		
JOINT AND WELD DESIGN			



WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE, FLOW RATE
1,4	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
2,5	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
3,6	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH
Rem*	GMAW	0.03"	ER-70-S-6	85-130	16-25	4-13	75% Ar, 25% CO2, 20-40 CFH

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Webb	Date: 9-5-18

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

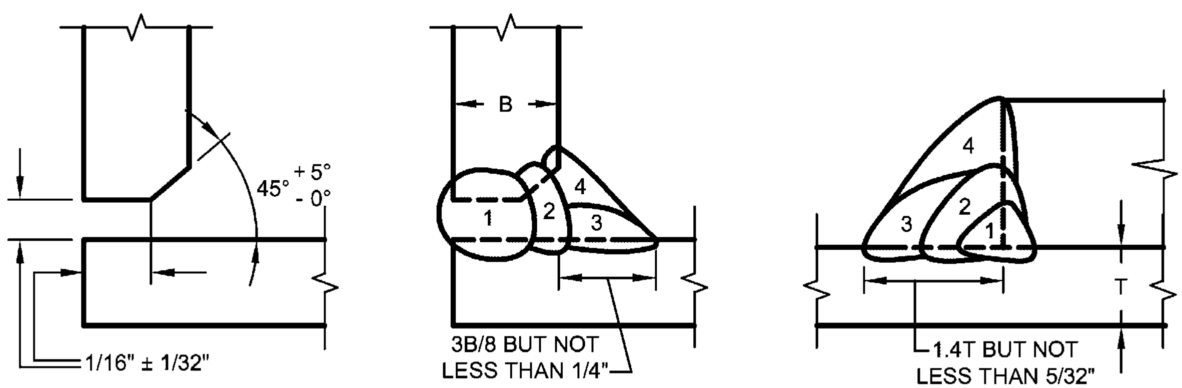
PROCEDURE NUMBER: F61
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E7018 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	E6010 Downhill E7018 Uphill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	3/32”	E6010	50-100	18-32	4-14	N/A
2	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
3	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
Rem.*	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
1/8” (E6010, Pass 1)	60-130	18-38	4-15
1/8” (E7018, Pass 2 – Remaining)	90-160	20-40	4-12

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved:	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

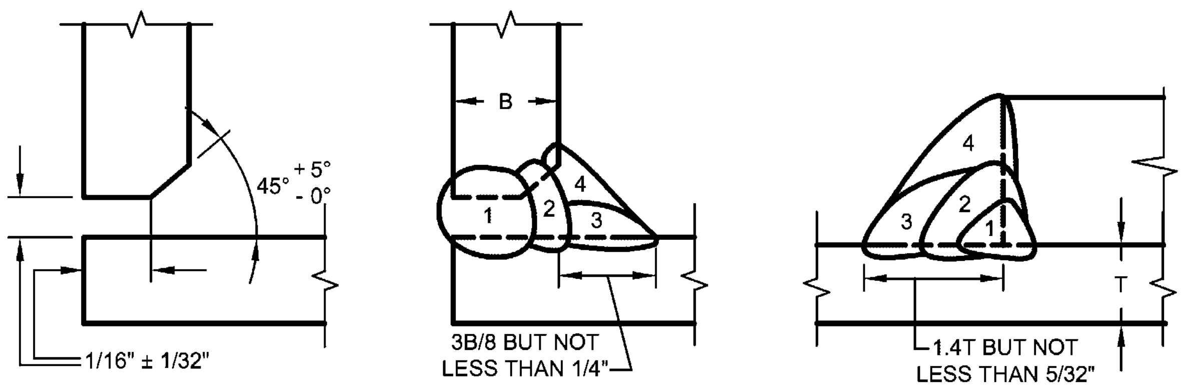
PROCEDURE NUMBER: F62
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	Gr. B ≤ X42
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.75” O.D. / 0.188” ≤ 0.750” W.T.
FILLER MATERIAL:	AWS E6010 Root, E7018 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	E6010 Downhill E7018 Uphill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	Gas Mixture and Percent
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
3	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
Rem.*	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, All passes)	50-100	18-32	4-14
1/8” (E7018, Pass 2 - Remaining)	90-160	20-40	4-12

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey a Webb	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

PROCEDURE NUMBER: F64

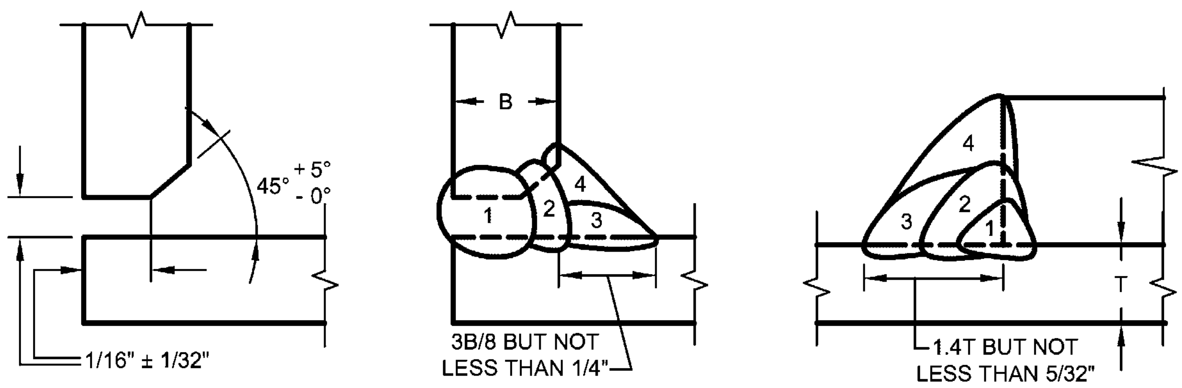
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)
PIPE AND FILLER MATERIAL REQUIREMENTS	
PIPE GRADES QUALIFIED:	X46 ≤ X52
PIPE DIAMETER / W.T. RANGE QUALIFIED:	< 2.375" O.D. / 0.188" ≤ 0.750" W.T.
FILLER MATERIAL:	AWS E6010 Root, E7018 Hot and Filler Passes

PRODUCTION WELDING CONDITIONS

PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	E6010 Downhill E7018 Uphill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL		WELDING PARAMETERS		TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
		SIZE	CLASSIFICATION	AMPERAGE	VOLTAGE		
1	SMAW	3/32"	E6010	50-100	18-32	4-14	N/A
2	SMAW	3/32"	E7018	70-110	20-35	2-10	N/A
3	SMAW	3/32"	E7018	70-110	20-35	2-10	N/A
Rem.*	SMAW	3/32"	E7018	70-110	20-35	2-10	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
1/8" (E6010, All passes)	60-130	18-38	4-15
1/8" (E7018, Pass 2 – Remaining)	90-160	20-40	4-12

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: [signature]	Date: 10-7-16

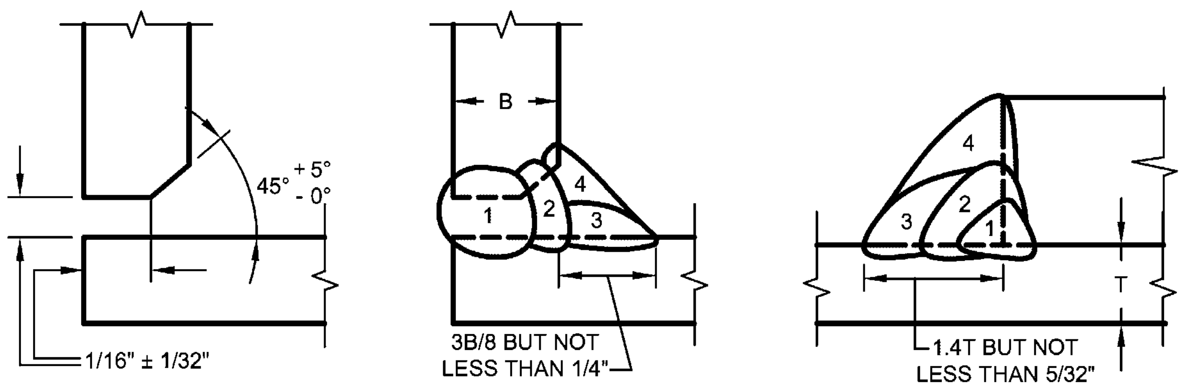
This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

AVISTA Utilities

PROCEDURE NUMBER: F65
Weld Category: All Pressures, All % SMYS

WELDING PROCESS:	Manual Shielded Metal Arc – (SMAW)		
PIPE AND FILLER MATERIAL REQUIREMENTS			
PIPE GRADES QUALIFIED:	X46 ≤ X52		
PIPE DIAMETER / W.T. RANGE QUALIFIED:	2.375” ≤ 12.750” O.D. / 0.188” ≤ 0.750” W.T.		
FILLER MATERIAL:	AWS E6010 Root, E7018 Hot and Filler Passes		
PRODUCTION WELDING CONDITIONS			
PRODUCTION PIPE POSITION:	Pipe in Horizontal or Vertical Fixed Position	DIRECTION OF WELDING:	E6010 Downhill E7018 Uphill
NUMBER OF WELDERS:	One Minimum	WELDING TECHNIQUE:	Stringer or Weave
PREHEAT METHOD:	Propane or Oxy-acetylene	TEMP. MEASUREMENT:	Pyrometer, Infrared Gun, or Temperature Sticks
METHOD OF WELD CLEANING:	Power Brushing or Grinding		
WELD CURRENT / POLARITY:	Direct Current / Reverse Polarity	POSTHEAT TREATMENT:	None Required
TYPE / REMOVAL OF CLAMP:	As Needed		
TIME BETWEEN PASSES:	5 Minutes Max. Between Root/Hot Pass and One Fill Pass; Remaining Passes within 24 hrs.		
PREHEAT / INTERPASS TEMP:	200° F minimum - 400° F maximum		

JOINT AND WELD DESIGN



JOINT DESIGN (BRANCH) WELD PASS SEQUENCE (BRANCH) WELD PASS SEQUENCE (SOCKET)

WELDING PARAMETERS AND ELECTRICAL CHARACTERISTICS

PASS NO.	PROCESS	FILLER MATERIAL SIZE	FILLER MATERIAL CLASSIFICATION	WELDING PARAMETERS AMPERAGE	WELDING PARAMETERS VOLTAGE	TRAVEL SPEED (IPM)	GAS MIXTURE AND PERCENT
1	SMAW	1/8”	E6010	60-130	18-38	4-15	N/A
2	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
3	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A
Rem.*	SMAW	3/32”	E7018	70-110	20-35	2-10	N/A

OPTIONAL APPROVED WELDING PARAMETERS FOR USE WITHIN ABOVE SPECIFIED CLASIFICATION

ELECTRODE DIAMETER	AMPERAGE RANGE	VOLTAGE RANGE	TRAVEL SPEED RANGE (IPM)
3/32” (E6010, Pass 1)	50-100	18-32	4-14
1/8” (E7018, Pass 2 - Remaining)	90-160	20-40	4-12

*Remaining number of passes needed to achieve joint and weld design requirements as shown above.

PROCEDURE CERTIFICATION

Approved: Jeffrey A Wolf	Date: 10-7-16

This procedure was conducted in accordance with and meets the requirements of API 1104, Twentieth Edition and DOT Part 192.

3.23 JOINING OF PIPE - PLASTIC (POLYETHYLENE) - HEAT FUSION

SCOPE:

To establish a uniform heat fusion procedure to produce sound, homogeneous joints which adhere to the applicable manufacturer and regulatory codes.

REGULATORY REQUIREMENTS:

§192.271, §192.273, §192.281, §192.283, §192.285, §192.287, §192.756

WAC 480-93-080

OTHER REFERENCES:

ASTM F2620
Performance Pipe Bulletin PP-750
Plastics Pipe Institute (PPI) Reference 33 (TR-33)
Plastics Pipe Institute (PPI) Technical Note 13 (TN-13)

CORRESPONDING STANDARDS:

Spec. 2.13, Pipe Design - Plastic
Spec. 3.13, Pipe Installation – Plastic
Spec. 3.34, Squeeze-Off of PE Pipe and Prevention of Static Electricity

JOINING METHODS:

General

Heat fusion is one technique used to join plastic (polyethylene) pipe, either by manual or hydraulic methods. Butt fusions on 6” pipe shall only be done using hydraulic methods. Heat may not be applied with a torch or other open flame.

Pipe and fitting fusion shall be performed by qualified trained personnel. Copies of qualified written joining procedures must be located on site where plastic pipe joining is being performed.

Qualifications of Persons to Join Plastic Pipe

No persons shall perform joining on polyethylene pipe until that person has received training in the procedures and has made acceptable specimen joints similar to those that will be made in the field. This person must also hold a current qualification. Persons must be re-qualified once each calendar year not to exceed 15 months. If any field production joints fail during pressure testing then the individual who performed that particular joining process is no longer qualified and must re-qualify on that fusion procedure unless it can be shown that the joint failed due to factors that are outside of the joiner’s control (i.e., equipment malfunction or material flaw).

The specimen joints must be visually examined during and after joining and found to have the same appearance as a joint or photographs of a joint that is acceptable under the manufacturer's procedures and tested in accordance with ASTM F2620. The joint must be cut into at least 3 longitudinal straps, each of which is found not to contain voids or discontinuities on the cut surfaces of the joint area and be deformed by a bending test. If failure occurs, it must not initiate in the joint area.

WAC 480-93-080: Requires employees working in the state of Washington to requalify under an applicable procedure, if during any twelve month period the person has not made any joints under that procedure.

Employees or contractors working in or with potential to work in the state of Washington shall complete a plastic pipe joint for each type of joining process that an individual is qualified in following annual Operator Qualification Training, between April 1 and December 31. The results of the completed joints shall be tracked on form N-2596, "Plastic Pipe Field Joint Tracking, Washington". Successful completion of this mid-year qualification will ensure compliance with the twelve month qualification interval in Washington State. Failure to complete and document a PE joint will render the individual unqualified to perform that PE joining procedure starting on January 1 and until requalification is performed in first quarter Refresher Training.

Gas Managers are responsible for ensuring compliance of their employees that work in Washington State. Completed joint tracking forms shall be sent to the appropriate Compliance Technician for retention. Completed joint tracking forms shall be retained for three years.

Marking Joints

For all types of plastic joints, the qualified individual who performed the joint shall use a permanent marker to legibly sign the pipe with their first initial and full last name and shall also mark the date of the joint. It is recommended to write down the time that the joint was fused so that the appropriate cooling times can be easily determined.

Pipe Joining Certification Record

Each individual that successfully qualifies or requalifies on plastic pipe joining shall be issued a company Plastic Pipe Joining Certification Record. This certification record indicates the name of individual, date of certification, procedures under which the individual is qualified, and the expiration date of the certificate. The individual must have the record and the joining procedures available for inspection when performing plastic pipe joining in the field.

Maintenance and Calibration of Heat Fusion Equipment

Avista and its contractors must maintain equipment used in joining plastic pipe in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints as noted in §192.756. For Avista and its contractors, documentation of this requirement shall be completed through the signing of the Pressure Test Information Sticker (Form N-2490 or similar) on the applicable as-built construction document.

By signing the aforementioned document, an operator qualified individual is attesting that construction complied with current company standards / specifications and specifically in this case, that the heat fusion equipment is being maintained as appropriate. See the Manufacturer's Operating Instructions Manual for Gas Operations, Sections 2 and 3 (as applicable) for fusion equipment maintenance specifics.

BUTT FUSION PROCEDURES:

General

The following butt heat fusing procedure shall be strictly followed for each joint in order to produce sound homogeneous joints for the following like materials – DRISCOPIPE, DRISCOPLEX, ENDOT, PLEXCO 2406, POLYPIPE, and UPONOR 2406. Avista has adopted Performance Pipe's procedure for butt fusions from Bulletin PP-750, which is in alignment with ASTM F2620.

Avista's approved butt fusion procedure also aligns with the Generic Butt Fusion Joining Procedure for Field Joining of Polyethylene Pipe that was tested per CFR 192.283 and published as part of Technical Reference 33 (TR-33) in 2012 as a follow-up to Technical Note 13 (TN-13) published in 2007 both by the Plastics Pipe Institute (PPI).

A butt fusion shall not be made closer than 3 pipe diameters or 12 inches, whichever is greater, from a previous squeeze point. Failure to meet these separations may result in damage to the joint. Refer to Spec 3.34 related to requirements for squeezing plastic pipe. Regardless of the cutter being used, when cutting a PE pipe to length before fusing take precaution to eliminate or minimize the introduction of contamination to the pipe surfaces or the fusion equipment. Refer to butt fusion procedure (Step 1.a below) for a list of common contaminants.

Heating Tool

Heating tool surfaces must be up to temperature before you begin. All points on both heating tool surfaces where they will contact the pipe or fitting ends must be within the parameters listed in the heater surface temperature table below. The maximum temperature difference between any two points on the heating surfaces must not exceed 20 degrees F. It is recommended to periodically check the accuracy of the infrared or contact pyrometer by using ice water. You should observe a reading very close to 32 degrees F.

Butt Fusion
Heater Surface Temperature
DRISCOPIPE, DRISCOPLEX, ENDOT, PLEXCO, POLYPIPE, AND UPONOR 2406

Heater Surface Temperature	Interface Pressure
400°F min - 450°F max*	75 +/- 15 psi

**Note: It is recommended that the iron temperature on the outer surface where the actual PE pipe touches the iron be between 430°F and 450°F.*

1. Before installing the component (pipe or fitting) in the fusion machine, clean the inside and outside of the component (pipe or fitting) ends by wiping with a clean, dry, lint-free non-synthetic cloth or paper towel to remove all foreign matter and potential contaminants. Replace cloth often as foreign matter and contaminants build up on the surface. If the contamination cannot be removed this way, wash the pipe with water and a clean cloth or paper towel to remove the contamination, rinse the pipe with water and dry thoroughly with a clean, dry, lint-free non-synthetic cloth or paper towel. If contamination such as soap was transferred to the pipe ends during cutting, use 90% or greater isopropyl alcohol or acetone on a clean cloth or isopropyl alcohol wipes on the ends of the pipe to clean the contamination, and allow to dry thoroughly. Do not use the facer to remove contamination. Refer to 1.a. below for a list of common contaminants. Pipe preparation and cleaning are critical to any fusion process. Improperly cleaned or prepared pipe ends may result in contamination of the fusion equipment and a poor fusion compromising joint performance.

a. **Common Potential Contaminants** include but are not limited to the following: release agents (silicone or soybean products), silicone based lubricants, petroleum based products, lubricating oils, rust inhibitors, wax, solvent residue, water/moisture, dirt/dust, plastic shavings, natural body oils, grease, bentonite drilling mud or dust from drilling mud, soap, etc.

2. Align the components with the machine, place them in the clamps, and then close the clamps. Do not force pipes into alignment against open fusion machine clamps. When working with coiled pipe, if possible, “S" the pipes on each side of the machine to compensate for coil curvature and make it easier to join. Component ends should protrude past the clamps enough so that facing will be complete. Bring the ends together and check high-low alignment. Adjust alignment as necessary by tightening the high side down.

3. Insert facing unit between pipe or fitting ends and lock onto guide rods. Face pipe ends to the stops. Place the facing tool between the component ends and face them to establish smooth, clean, parallel mating surfaces. Complete facing produces continuous circumferential shavings from both ends. Face until there is a minimal distance between the fixed and moveable clamps. Some machines have facing stops. If stops are present, face down to the stops. Remove the facing tool and clear all shavings and pipe chips from the component ends and ensure pipe ends are clean. Do not touch the component ends with your hands after facing.

4. After facing is complete, check alignment of pipe ends to ensure the maximum OD high-low misalignment is less than 10% of the pipe minimum wall thickness. Adjust high-low if necessary. If adjustment is made, reinsert facing unit and reface to the stops. Bring the component ends together, check alignment, and check for slippage against fusion pressure. Look for complete contact all around both ends with no detectable gaps, and outside diameters in high-low alignment. If necessary, adjust the high side by tightening the high side clamp. Do not loosen the low side clamp because components may slip during fusion. Re-face if high-low alignment is adjusted.

5. Check temperature at heater plate and compare with heater surface temperature table, then wipe surface clean. Verify the heating tool is maintaining the correct temperature in the fusion zone by using an approved infrared or contact pyrometer. Place the heating tool between the component ends and move the ends against the heating tool. The initial contact should be under moderate pressure to ensure full contact. Hold contact pressure very briefly then release pressure without breaking contact. Pressure must be reduced to contact pressure at the first indication of melt around the pipe ends. Hold the ends against the heating tool without force. Beads of melted polyethylene will form against the heating tool at the component ends. When the proper melt bead size is formed, quickly separate the ends, and remove the heating tool.

Minimum Melt Bead Size Table

Main Pipe Sizes (in)	Minimum Melt Bead Size (in)
1 1/4 and smaller	1/32
2 through 3	1/16
Above 3 through 8	3/16

During heating, the melt bead will expand out flush to the heating tool surface or may curl slightly away from the surface. If the melt bead curls significantly away (concave) from the heating tool surface, unacceptable pressure during heating may be indicated.

6. Immediately after heating tool removal, QUICKLY inspect the melted ends, which should be flat smooth and completely melted. If the melt surfaces are acceptable, immediately and in a continuous motion, bring the ends together and apply the correct joining force. Do not slam. Apply enough joining force to roll both melt beads over the pipe surface.

   The maximum time allowed for opening the machine, removing the heater, and bringing the pipe ends together is shown in the Maximum Heater Plate Removal Times Table below.

   Maximum Heater Plate Removal Times Table

Avista Pipe OD Sizes (in) & SDR	Maximum Heater Plate Removal Time (Seconds)
1/2” to 1 1/4” (All SDRs)	4
2” SDR 11; 3 IPS SDR 11.5	8
4” SDR 11.5	10
6” SDR 11.5	15

   If hydrocarbon contamination is encountered on the pipe face during a butt fusion, stop the fusion process. Do not complete butt fusion welds on the pipe unless sound pipe can be found to complete the fusion process. When contamination is a concern, it is preferred to use mechanical fittings on plastic pipe 2-inch diameter and smaller. For situations with pipe larger than 2-inch diameter where mechanical fittings are not available, it is recommended that electrofusion fittings be used to join pipe if contamination is a concern. Electrofusion fittings may be used on 2-inch and smaller, but mechanical connections are preferred. See Specification 3.24, Joining of Pipe – Plastic (Polyethylene) - Electrofusion for information regarding the electrofusion process. Contact Gas Engineering as necessary for additional assistance. Refer to the Butt Fusion Troubleshooting Guide at the end of this specification.

7. Hold joining force against the ends for a minimum of 11 minutes per inch of pipe wall thickness, refer to Butt Fusion Cooling Times Table. For ambient temperatures 100 °F and higher, additional cooling time may be needed. Do not try to shorten cooling time by applying water, wet cloths, etc. Pulling, installation, pressure testing, and rough handling shall be avoided for at least an additional 30 minutes.

8. On both sides, the double bead should be rolled over to the surface and be uniformly rounded and consistent in size all around the joint. The double bead width should be 2 to 2-1/2 times its height above the surface, and the v-groove depth between the beads should not be more than half the bead height.

   When butt fusing to molded fittings, the fitting-side bead may have an irregular appearance. This is acceptable provided the pipe-side bead is correct. It is not necessary for the internal bead to roll over to the inside surface of the pipe.

Butt Fusion Cooling Times Table
DRISCOPIPE, DRISCOPLEX, ENDOT, PLEXCO, POLYPIPE, AND UPONOR 2406

Pipe Size	SDR	Cooling Time (min)	Cool to Rough Handle (min)
2" IPS	11	2-1/2	30
3" IPS	11.5	3-1/2	30
4" IPS	11.5	4-1/2	30
6" IPS	11.5	6-1/2	30

9. If at any time during the fusion process there is doubt regarding the success of the fusion or if contamination is a concern, abandon and remove the fusion joint and re-start the process of making a new fusion joint.

HYDRAULIC BUTT FUSION:

Refer to the manufacturer's operation manual for maintenance and special operation of the fusion equipment.

The procedure for butt fusion above is the same; however, when using a hydraulic fusion machine, the fusion pressure must be determined using the recommended interface pressure from the pipe manufacturer and the following procedures:

The pressure gauge on the manifold block indicates the pressure at the carriage valve. How much pressure depends on the position of the selector valve and the pressure set on the specific pressure-reducing valve. With the selector valve up, the facing pressure can be set. It may be necessary to adjust the carriage speed, while facing, with the top pressure-reducing valve to control facing speed.

Shift the selector valve to the center position and set the heating pressure (if required). If heating pressure is not required, set the pressure reducing valve at its lowest setting or the drag pressure, whichever is higher. The heating and fusion pressures can be calculated using the following calculations:

Determining Drag Pressure:

1. After facing the pipe, move the carriage so that the pipe ends are approximately 2-inches apart.
2. Shift the carriage control valve to the middle (neutral) position.
3. Select the heating mode, and adjust the middle pressure reducing valve to its lowest pressure by turning the valve counterclockwise.
4. Shift the carriage control valve to the left.
5. Gradually increase the pressure by turning the valve clockwise. Increase the pressure until the carriage moves.
6. Quickly reduce the heating pressure by turning the valve counterclockwise until the carriage is just barely moving.
7. Record the pressure. (This is the actual DRAG pressure, which is used in the calculation of the fusion pressure).

Determining Fusion Pressure:

The following is the calculation for determining fusion pressure:

$$\frac{(OD - t) \times t \times PI \times IFP}{TEPA} + DRAG$$

OD = Outside diameter of pipe (should be marked on pipe)
t = Wall thickness (OD divided by SDR)
PI = 3.1416
SDR = Standard dimension ratio (Should be marked on pipe – Refer to Note Below)
IFP = Manufacturer's recommended interfacial pressure (75 psig +/- 15)
TEPA = Total effective piston area (standard high force for specific machine)
DRAG = Force required to move pipe

Example: Calculating for 6-inch IPS pipe using a #28 McElroy machine

OD of Pipe = 6.625
SDR of Pipe = 11.5
IFP = 75 psi
DRAG = 30 psi (determined using above procedure)
TEPA = 4.710 (#28 McElroy machine)

$$\frac{(6.625 - .576) \times .576 \times 3.1416 \times 75}{4.710} + 30 \text{ psi drag} = \mathbf{204\ psi}$$

Note: Fusion of pipes or fittings with different SDRs is acceptable as long as the different materials only have up to one SDR difference (i.e., SDR 11 to SDR 13.5 or SDR 9 to SDR 11). When fusing pipes or fittings with unlike SDRs use the higher SDR (thinner wall pipe) when determining the required fusion pressure.

Hydraulic Fusion Pressures
#28 McElroy Machine (TEPA = 4.710)

Nominal Pipe Diameter	SDR	Fusion Pressure (PSI) (IFP = 60 PSI)*	Fusion Pressure (PSI) (IFP = 75 PSI)*	Fusion Pressure (PSI) (IFP = 90 PSI)*
2" IPS	11	19	23	28
3" IPS	11	41	51	61
4" IPS	11	67	84	100
6" IPS	11	145	181	218
3" IPS	11.5	39	49	58
4" IPS	11.5	64	80	97
6" IPS	11.5	139	174	209

* Fusion Pressures in this table do not include DRAG. Be sure to account for DRAG to determine proper hydraulic fusion pressure.

Hydraulic Shift Sequence:

1. Move the carriage to the right to open a gap and allow insertion of the heater plate.
2. Check the fusion position and shift the selector valve handle down to the fusing position. Allow the gauge pressure to drop to the machines minimum pressure setting.
3. Ensure that the heater surface is free of any potential contaminants. Use a clean non-synthetic cloth to clean the surfaces as necessary.
4. Verify heater temperature then insert heater between the pipe ends.
5. Prepare pipe for fusion as previously described in this specification (or as recommended by the pipe manufacturer).
6. Move the carriage to the left, bringing the heater into contact with both pipe ends.
7. Shift the selector valve to the center position and allow the gauge pressure to drop to the machines minimum pressure setting.
8. When the gauge drops to its minimum setting, return the carriage control valve to neutral position.
9. Allow the pipe to melt.
10. After obtaining the proper melt, shift the selector valve down to fusion position and move the carriage to the right just enough to remove the heater.
11. QUICKLY REMOVE THE HEATER and inspect the melted ends, which should be flat, smooth, and completely melted.
12. If the melt surfaces are acceptable, move the carriage to the left, bringing the pipe ends together under the pipe manufacturer's recommended pressure.
13. Allow the joint to cool under pressure as listed in the butt fusion procedure previously described in this specification (or as recommended by the pipe manufacturer).

Cold Weather Fusion

1. Carefully remove (by light tapping and wiping) ice, snow, or frost from inside and outside the pipe ends and the areas to be clamped in the joiner. Otherwise, they will melt when exposed to the heating tool and spot chill the polyethylene. This may cause incomplete fusion. Also, frost and ice on the clamping surfaces of the pipe may cause slippage during fusion.

2. In the case of high winds and rain, the heating tool should be shielded to prevent excessive heat loss and to keep the tool dry at all times. A canopy should be used to shield the heating tool and fusion area from wind, snow, and rain.

3. Always check the manufacturer's recommendations for any temperature limitations with equipment, such as the "Line Tamer", which has problems re-rounding pipe in freezing conditions.

The length of the heating cycle necessary to obtain a complete melt pattern will depend not only on the outdoor temperature, but wind conditions, pipe tolerances, and operator variation. Melt pattern is the key.

Butt Fusion Troubleshooting Guide

BUTT FUSION BEAD TROUBLESHOOTING GUIDE	
Observed Condition	**Possible Cause**
Excessive double bead width	Overheating; excessive joining force
Double bead v-groove too deep	Excessive joining force; insufficient heating; pressure during heating
Flat top on bead	Excessive joining force; overheating
Non-uniform bead size around pipe	Misalignment; defective heating tool; worn equipment; incomplete facing
One bead larger than the other (except when fusing pipe to molded fitting or when fusing dissimilar materials)	Misalignment; component slipped in clamp; worn equipment; defective heating tool; incomplete facing
Beads too small	Insufficient heating; insufficient joining force
Bead not rolled over to surface	Shallow v-groove – Insufficient heating & insufficient joining force Deep v-groove – Insufficient heating & excessive joining force
Beads too large	Excessive heating time
Squared outer bead edge	Pressure during heating
Rough, sandpaper-like, bubbly, or pockmarked melt bead surface	Hydrocarbon contamination

Compatibility/Cross Fusions

When connecting polyethylene pipe and/or fittings that have different densities or unlike material properties it is preferred that an electrofusion process or mechanical fittings be utilized. However, if circumstances require then the butt-fusion procedure outlined earlier in this section may be utilized if the following conditions are met:

- Material Melt Index (MI) – 0.05 g/10 min < MI < 0.25 g/10 min
  (i.e. – Plexco, Driscoplex, Driscopipe, Yellowstripe, Uponor & Polypipe PE 2406/2708 and PE 100/3408/4710)

One bead may be larger than the other when fusing two dissimilar materials. This is acceptable provided both bead sizes are uniform around their respective pipes.

When connecting to Driscopipe 7000, Driscopipe 8000, Driscopipe 8600, or DuPont/Uponor “Aldyl A" pipe, connections shall be made utilizing either the electrofusion process or by use of mechanical fittings. These older materials have higher melt indices that are outside the acceptable range for cross fusing using this butt fusion process.

3.24 JOINING OF PIPE - PLASTIC (POLYETHYLENE) - ELECTROFUSION

SCOPE:

To establish procedures to be followed in the joining of plastic pipe by means of the electrofusion process in Avista's natural gas distribution systems.

REGULATORY REQUIREMENTS:

§192.271, §192.273, §192.281, §192.283, §192.285, §192.287, §192.756

WAC 480-93-080

CORRESPONDING STANDARDS:

Spec. 2.13, Pipe Design - Plastic
Spec. 3.13, Pipe Installation – Plastic
Spec. 3.23, Joining of Pipe – Plastic (Polyethylene) – Heat Fusion
Spec. 3.33, Repair of Plastic (Polyethylene) Pipe
Spec. 3.34, Squeeze-Off of PE Pipe and Prevention of Static Electricity

General

Gas employees performing electrofusion of pipe and fittings shall be properly trained in this procedure and shall qualify initially and re-qualify annually. Persons must be re-qualified once each calendar year not to exceed 15 months.

Refer to Specification 3.23, Joining of Pipe – Plastic (Polyethylene) – Heat Fusion, "Qualifications of Persons to Join Plastic Pipe" for specific qualification requirements and required joint testing for the joining of plastic pipe which includes joining by electrofusion. The guidance and requirements in that subsection are required for electrofusion joining qualification. If any field electrofusion joints fail during pressure testing then the individual who performed that particular joining process is no longer qualified and must re-qualify on that electrofusion procedure unless it can be shown that the joint failed due to factors that are outside of the joiner's control (i.e., equipment failure or material flaw).

The following procedures are for the joining of polyethylene plastic pipe during construction or repair operations. This electronic fusion system utilizes a sequence processor or control unit and a specially designed electrofusion fitting. The sequence processor is computerized in order to provide precise control of fusion time, temperature, and joining pressure. A recognition resistor identifies fittings to the control unit and automatically sets the correct fusion time. The control unit also monitors critical aspects of the fusion process and will sound an alarm if part of the process is faulty or incomplete. A self-diagnostic function is built into the unit and is accessible by pressing and holding the start button at power up or by use of a personal computer. The electrical fusion system is not intrinsically safe or explosion proof. In repair situations where 100 percent shut off is not available, escaping gas should be vented away from the control unit.

Electrofusion fittings shall have been tested and qualified by the manufacturer under §192.283 and ASTM F1055 prior to use as an approved fitting. Currently approved electrofusion style fittings include Georg Fischer Central Plastics, Innogaz, IPEX/Friatec/Frialen, Jameson, and M.T. Deason all of which meet these qualifications according to each manufacturer. Reference manufacturer's technical information and cut sheet data for additional information.

The manufacturer's instructions should be consulted before performing any electrofusion procedures. Reference Avista's Manufacturer's Operating Instructions Manual for Gas Operations for additional information.

An electrofusion shall not be made closer than 3 pipe diameters or 12 inches, whichever is greater, from a previous squeeze point. Failure to meet these separations may result in damage to the fittings or joint. Clearances from previous squeeze points shall be visually confirmed (i.e., exposed), except for new pipeline installations where the field as-built documents have not yet been submitted and the absence of previous squeeze points can be inferred with certainty. Refer to Spec 3.34 related to requirements for squeezing plastic pipe.

Maintenance and Calibration of Heat Fusion Equipment

Avista and its contractors must maintain equipment used in joining plastic pipe in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints as noted in §192.756. For Avista and its contractors, documentation of this requirement shall be completed through the signing of the Pressure Test Information Sticker (Form N-2490 or similar) on the applicable as-built construction document.

By signing the aforementioned document, an operator qualified individual is attesting that construction complied with current company standards / specifications and specifically in this case, that the heat fusion equipment is being maintained as appropriate. See the Manufacturer's Operating Instructions Manual for Gas Operations, Sections 2 and 3 (as applicable) for fusion equipment maintenance specifics.

Calibration Timeframes for Electrofusion Equipment

Electrofusion machines should be returned to the factory for calibration or maintenance on a time basis as recommended by the manufacturer of the equipment and the record of calibration/maintenance sticker updated at that time. See the table below for recommended maintenance schedule by manufacturer.

Manufacturer	Recommended Service/Maintenance Schedule
IPEX Friamat	Annually
IPEX Genesis F3	Every 3 Years
Georg Fisher/Central Plastics MSA 340	Every 2 Years

Marking Joints

For all types of plastic joints, the qualified individual who performed the joint shall use a permanent marker to legibly sign the pipe with their first initial and full last name and shall mark the date of the joint. It is recommended to write down the time that the joint was fused so that the appropriate cooling times can be easily determined.

STANDARD COUPLING AND ENDCAP JOINING PROCEDURES:

1. Determine that all necessary tools and equipment are available and good working order before beginning the procedure. When using a generator, the generator should always be engaged before plugging the control unit in. A 3500 watt minimum generator is required, although 5000 watt is recommended. A 110 volt, 30 amp, GFCI A/C power source will also be required.

2. It is critical that the pipe ends to be joined have a square, even cut. It is recommended that a pipe tape be used to mark the pipe prior to cutting to help ensure a square cut. Once the pipe is cut, remove any burrs or shavings from the pipe ends that may have occurred during the cutting process.

3. Thoroughly clean each pipe end inside and out using clean water or isopropyl alcohol with a clean, lint-free cloth to remove any foreign matter or potential contaminants. Replace cloth often as foreign matter and contaminants build up on the surface. Refer to Specification 3.23 – Sheet 3, Joining of Pipe – Plastic (Polyethylene) – Heat Fusion, "Butt Fusion Procedures" for a list of common contaminants. Pipe preparation and cleaning are critical to any fusion process. Improperly cleaned pipe may result in a poor fusion and a potentially compromised joint.

4. Once the fusion area is cleaned, visually check for scratches in the fusion area that appear to be 10 percent or more of the pipe wall. Minor scratches are not unusual on installed pipe, especially on pipe installed via directional drill. Use an approved pit gauge to measure the depth of scratches that are of concern. The edges of the scratch may need to be widened slightly to ensure the measurement point of the gauge can reach the bottom of the scratch to properly measure the depth. Care must be taken not to deepen the scratch. If a scratch is found to be equal to or greater than 10 percent of the wall thickness of the pipe, either replace the section with new pipe or repair the pipe using an approved repair fitting, per Specification 3.33, Repair of Plastic Pipe. If not, proceed to Step 5 in preparation for electrofusion fitting installation.

5. Prior to peeling the pipe, scrape the fusion surface with a scraper, as needed, to remove any ridges that may have been created from displaced material due to scratching. This will help ensure a uniform surface prior to peeling the pipe. Use only scraping equipment recommended by the manufacturer or approved by Avista (emery cloth and sandpaper are not approved tools). Once scraped, or if scraping is not required, peel the pipe using an approved peeler to remove any surface oxidation along with any contamination such as bentonite, oil, grease, or perspiration that may have built up on the outside layer of pipe. Failure to do so could result in contamination within the fusion zone. A full encirclement peeler is recommended. For best results, use a silver metallic permanent marker (do not use a black permanent marker or grease pencil) to mark lines on the area of pipe prior to peeling. The mark lines should run parallel with the pipe and be about 1-inch apart over the entire area of the pipe to be peeled. Secure the peeling tool on the pipe and begin the peeling process. Continue to peel until mark lines are removed. This is usually accomplished with 1 pass of the tool. Do not exceed more than one pass of the peeler on 2-inch and smaller diameter pipe and two passes of the peeler on pipe sizes larger than 2-inch. If necessary, during the peeling process, remove the tool and clean the blade area with a clean, dry, lint-free cloth to remove build-up of material (isopropyl alcohol also works well to clean the blade). It is possible scratches may still exist in the fusion zone after scraping and peeling. This is acceptable as long as the scratches are clean and are not deep enough to have removed 10 percent or more of the original pipe wall. Once peeling is complete, deburr the outside edge of the pipe end near the prepared fusion surface with a scraper. This should help to protect the wire coils of the electrofusion fitting when sliding the fitting over the end of the pipe.

6. Possible recontamination of the prepared surface should be avoided. Do not touch the peeled pipe surfaces or the inside of the fitting with your hands as perspiration and body oils could contaminate joining areas and affect joint integrity. If contaminates are suspected on the fitting, clean the fitting with isopropyl alcohol and a clean lint-free cloth. If contaminants are suspected on the pipe, or if the pipe was installed by a horizontal direction drill using bentonite, clean ONLY the peeled/scraped area of the pipe with isopropyl alcohol and a clean lint-free cloth taking care not to wipe the pipe outside of the peeled area because contaminants may be redeposited onto the peeled/scraped surface. Let the alcohol evaporate completely prior to assembling the pipe and fitting.

7. Determine the stab depth of the fitting by measuring half the length of the coupling. Mark each pipe end an equivalent length with a silver metallic permanent marker. Do not use a black permanent marker or grease pencil to mark the stab depth as this may contaminate the pipe surface.

8. Slide the coupling or endcap onto one pipe end until the squared end of the pipe meets with the internal stop in the fitting. With couplings, insert the second pipe end into the fitting so that the end also meets the internal stops. If the fitting is being used for a repair the internal stops may be removed. Check the measurement marks to assure the pipe is inserted to the proper stab depth.

9. If there is a possibility of movement in the assembly during the fusion cycle, an alignment clamping tool should be utilized. Be sure to maintain the proper stab depth. For best results, the alignment clamps should be placed as close to the fitting as possible. For coiled pipe larger than 3/4-inch (and for other binding installations), the use of two clamps on each side of the coupling is recommended. Ensure the clamps are supported to avoid putting stress on the fusion joint.

10. Connect the control unit to the A/C power source. The sequence processor will automatically perform a quick diagnostic check.

11. Attach the leads from the control unit to the fitting terminals. If a barcode is present, scan the barcode to identify the fitting. Verify the correct fitting type is displayed on the control unit.

12. Press the start button to begin the fusion cycle. Fusion cycle time will count down on the visual display.

13. When the fusion cycle is complete, “End of Fusion” as well as the “Cooling Time” will appear on the visual display. Disconnect the leads from the fitting and allow the fusion to cool for the minimum time before removing the clamp(s).

14. After removing the clamp(s), additional cooling time shall be allowed before subjecting the joint to bending, burying, pressure testing, or similar handling or backfill stress. Refer to the table at the end of this specification for recommended cooling times for various sized electrofusion fittings.

15. Fusion joints shall be subjected to a pressure test as specified in this standard and a visual soap or leak detector test as appropriate.

Note 1: If the fitting is installed and the normal electrofusion process is complete, but there is no indication of the pop-up indicator rising, then additional investigation is required. Under these circumstances, if the electrofusion fitting feels hot to the touch within each fusion zone, alignment of the fitting appears good after the fusion and the fitting passes the required pressure testing per Spec 3.18 then the fitting may remain. If not, or there are any indicators of an unsuccessful fusion then the fitting shall be cut out and replaced. Not all fittings have pop-up indicators (i.e., Georg Fischer Central Plastics). If a pop-up indicator is not present on the fitting, then follow the directions and information provided by the electrofusion processor during installation as well as perform the investigation described above.

Note 2: If there are any doubts about the success of the electrofusion process the fitting shall be cut out and replaced.

REPAIR COUPLING JOINING PROCEDURE:

1. Make sure that there is enough room in the excavation to install the fitting and the clamping devices. This repair procedure will require 2 electrofusion fittings per repair section.

2. Cut out and remove the section of damaged pipe.

3. Follow the procedures as outlined under "Standard Coupling & Endcap Joining Procedures" steps #1 through #7 for cleaning, preparing, and marking the existing pipe ends.

4. Remove the internal fitting stops by bottoming the pipe end to the internal stops. Apply a sudden thrust to the end of the coupling so that the stops cleanly snap out. Make sure that the fitting stops are completely removed from the I.D. of the fitting. To avoid contamination of the inside of the coupling do not use your fingers to remove the loose stops.

5. Slide the fittings onto each of the existing pipe ends.

6. Insert the new section of pipe into place. Make sure that both ends of the new section are cleaned, prepared, and marked properly. The new section should fit into place between the existing pipe ends with no more than approximately 1/16-inch clearance on each side.

7. Slide a coupling over the pipe junction until both measurement marks are visible. Measurement marks should not extend more than 1/16-inch from the coupling end. Repeat on the other side of the repair section.

8. Follow the procedures as outlined under "Standard Coupling & Endcap Joining Procedures" steps #10 through #15, to complete the fusion process.

SADDLE JOINING PROCEDURE:

1. Follow steps #3 and #4 as outlined under "Standard Coupling and Endcap Joining Procedures" to clean the surfaces to be joined with a clean cloth to remove any dirt or contamination and inspect the pipe for scratches or other damage. If a scratch equal to or deeper than 10 percent of the wall thickness of the pipe is present, either replace the section with new pipe or repair the pipe using an approved repair fitting, per Specification 3.33, Repair of Plastic Pipe.

2. Center the saddle fitting on the pipe to determine the required fusion area. Mark the pipe with a silver metallic permanent marker to show the length of the area to be prepared.

3. Prior to peeling the pipe, scrape the entire fusion surface on the pipe with a scraper, as needed, to remove any ridges that may have been created from displaced material due to scratching. This will help ensure a uniform surface prior to peeling the pipe. Use only scraping equipment recommended by the manufacturer or approved by Avista (emery cloth and sandpaper are not approved tools for electrofusion installations). Once scraping is complete, or if scraping is not required, peel the entire pipe surface required for the saddle in order to remove oxidation and potential contaminates. A full encirclement peeler is recommended.

   Follow step #5 in the procedures as outlined under "Standard Coupling & Endcap Joining Procedures" for scraping and peeling.

4. Possible recontamination of the prepared surface should be avoided. Do not touch the peeled pipe surface or the inside of the fitting with your hands as perspiration and body oils could contaminate joining areas and affect joint integrity. If contaminates are suspected on the fitting, clean the fitting with isopropyl alcohol and a clean lint-free cloth. If contaminants are suspected on the pipe, or if the pipe was installed by horizontal direction drill using bentonite, clean ONLY the peeled area of the pipe with isopropyl alcohol and a clean lint-free cloth taking care not to wipe the surrounding pipe because contaminants may be redeposited onto the prepared surface. Let the alcohol evaporate completely prior to assembling the pipe and fitting.

5. Position the saddle on the clean, peeled area and place the appropriate saddle clamp under the pipe, adjacent to the saddle fitting.

6. Slide the clamping tool onto the edges of the saddle fitting until the clamp is squarely aligned beneath the fitting. Tighten the clamp to secure the fitting in place.

7. Follow steps #10 through #15 in “Standard Coupling & Endcap Joining Procedures” to complete the fusion process. The table at the end of this specification should be consulted for the proper cooling times for tapping tees.

ALDYL A TEE REPAIR PROCEDURE:

1. Before initiating the repair, be sure the electrofusion equipment and qualified personnel are on site. A universal barcode electrofusion control box is the preferred method for translating the barcode data.

2. After excavating the tee, clean the stack and (using approved scraping and peeling tools) scrape and peel the outside diameter of the stack down to the intersection of the tee outlet, as needed, in preparation for electrofusion. Follow step #5 in “Standard Coupling and Endcap Joining Procedures”.

3. Either scrape and peel the outside diameter of the repair fitting insert using approved tools or clean the outside diameter with isopropyl alcohol. If the insert is contaminated or has been out of the bag and exposed to the environment for an extended time, it should be discarded.

4. Install the prepared insert into the 1.25-inch coupling until the shoulder of the insert stops against the coupling.

5. Install the coupling over the stack of the tee until it bottoms out.

6. Electrofuse the coupling to the tee and insert using the barcode mode or manually input the code using the advanced functions of the processor.

7. After removing the electrofusion cables, allow the assembly to cool for 10 minutes.

8. If not already done, lightly lubricate the O-ring (Dow Corning Silicone Grease #111 or equal) and install it on the plug.

9. Thread the plug assembly into the insert until it bottoms out. The top of the plug should be flush with the top of the insert. Use a standard 1/2-inch square drive to turn the plug into the insert. This completes the repair kit assembly process.

SERVICE LINE JOINING PROCEDURE:

To make the service line connection, follow the "Standard Coupling & Endcap Joining Procedures" as outlined above. The clamp utilized should be one provided by or recommended by the manufacturer specifically for performing the service line connection. The table at the end of this specification should be consulted for the proper cooling times for service line connections (reducers).

TAPPING PROCEDURE:

1. Ensure the joint has completely cooled before attempting to perform this tapping procedure. Use a tapping tool recommended by the manufacturer.

2. To "punch" the main, remove the cap and insert the tapping tool.

3. Slowly turn the tapping tool clockwise to tap the main. Continue turning until the cutter contacts the lower stop inside the tee. The lower stop ensures that the proper "punch" depth has been achieved.

4. Back the tapping tool out by turning it counterclockwise until the cutter contacts the upper stop inside the tee. The upper stop ensures that the cutter is fully retracted so that gas flow is not restricted.

5. Install the cap by screwing it all the way down until the collar of the cap touches the front face of the drill spigot. Then loosen the cap half a turn to relieve the O-ring tension.

6. As a best practice, consider creating notes and/or marking the tee (e.g., tape, marker, etc.) to keep track of whether the tee has been tapped out.

REPAIR CLAMP JOINING PROCEDURE:

1. Measure the size of the damaged area of pipe and determine if the damaged area will completely fit into the cold zone area inside the dome of the repair clamp. The cold zone is the area of pipe that will be inside and in contact with the electrofusion fitting but away from the electrofusion melt zone. The cold zone helps to prevent the melt from extruding out of the joint. The cold zone diameter for each size of repair clamp is as follows:

   3-inch IPS = 2.0 inches (75 mm)
   4-inch IPS = 3.1 inches (78 mm)
   6-inch IPS = 3.3 inches (85 mm)

   If the damaged area of pipe will not fit underneath the dome and inside the cold zone, the repair clamp cannot be used, and a different repair method will need to be utilized or the damaged section will need to be replaced. Refer to Specification 3.33, Repair of Plastic Pipe, for approved repair methods.

2. Follow steps #3 and #4 as outlined under "Standard Coupling and Endcap Joining Procedures" to clean the surfaces to be joined with a clean cloth to remove any dirt or contamination and inspect the pipe for scratches or other damage. If a scratch equal to or deeper than 10 percent of the wall thickness of the pipe is present, either replace the section with new pipe or repair the pipe using an approved repair fitting, per Specification 3.33, Repair of Plastic Pipe.

3. Measure and mark the pipe surface covered by the fitting with a silver metallic permanent marker.

4. Prior to peeling the pipe, scrape the fusion surface on the pipe with a scraper, as needed, to remove any ridges that may have been created from displaced material due to scratching. This will help ensure a uniform surface prior to peeling the pipe. Use only scraping equipment recommended by the manufacturer or approved by Avista (emery cloth and sandpaper are not approved tools). Once scraping is complete, or if scraping is not required, peel the entire pipe surface required for the repair clamp to remove oxidation and potential contaminates. A full encirclement peeler is recommended. Follow step #5 in the procedures as outlined under "Standard Coupling and Endcap Joining Procedures" for scraping and peeling.

5. Do not touch the peeled pipe surface or the inside of the fitting with your hands as perspiration and body oils could contaminate joining areas and affect joint integrity. If contaminants are suspected on the fitting, clean the fitting with isopropyl alcohol and a clean lint-free cloth. If contaminants are suspected on the pipe, or if the pipe was installed by horizontal direction drill using bentonite, clean ONLY the peeled area of the pipe with isopropyl alcohol and a clean lint-free cloth taking care not to wipe the surrounding pipe because contaminants may be redeposited onto the prepared surface. Let the alcohol evaporate completely prior to assembling the fitting.

6. Align and install the repair clamp in the cleaned, peeled area over the damaged section of pipe ensuring that the damaged area of the pipe is completely encapsulated inside the dome of the fitting and inside the cold zone (refer to Step 1 for the cold zone size for each size of repair clamp). Firmly tighten all bolts, working diagonally, without using excessive force until the clamp is flush with the pipe. Assembly of pipe and fitting must be in a clean, supported, and stress-free condition as much as possible.

Note: Both halves of the repair clamp have electrofusion capability. The bottom half of the repair clamp (the smooth side without the raised dome) does not need to be electro fused to the pipe. Only the half covering the repair needs to be electro fused.

7. Follow the procedures outlined in "Standard Coupling & Endcap Joining Procedures" steps #10 through #15 to complete the fusion process. The table at the end of this specification should be consulted for the proper cooling times for repair clamps.

Re-fusion of Electrofusion Fittings

If during the first 25 percent of the electrofusion heat cycle the power supply to the fusion unit is lost (i.e., power outage, generator runs out of fuel, or the leads become disconnected) it is acceptable to re-fuse the electrofusion fitting as long as the fitting is allowed to cool for at least one hour unless ambient temperature is reached prior to one hour and the fitting remains undisturbed during the cooling process. If the fusion process is interrupted during the second attempt the fitting shall be cut out and replaced.

FUSION/COOLING TIMES BY MANUFACTURER

TABLE A: GF Central Plastics

Fitting (inches)	Fusion Times (sec)	Clamped Cooling Time (min)[1]	Pressurized / Tapping Time (min)	Rough Handling Time (min)
Couplings/Endcaps				
1/2 CTS	20	5	15	30
1/2 IPS	20	5	15	30
3/4 IPS	35	5	15	30
1 CTS	40	5	15	30
1 IPS	45	10	15	30
1-1/4 IPS	75	10	20	30
2 IPS	60	10	20	30
3 IPS	180	15	30	35
4 IPS	200	15	30	35
6 IPS	500	20	40	45
Reducers				
3/4 x ½	20	5	15	30
1 x ½	30	5	15	30
1 x ¾	30	5	15	30
2 x 1-1/4	45	10	20	30
Tapping Tees				
1-1/4 IPS	45	10	20	30
2 IPS	90	10	20	30
3 IPS	90	10	20	30
4 IPS	90	10	20	30
6 IPS	90	10	20	30
WB HV Tapping Tees				
2 x 1-1/4; 2 x 2	90	10	25	30
3 x 1-1/4; 3 x 2	60	10	25	30
4 x 1-1/4; 4 x 2	60	10	25	30
6 x 1-1/4; 6 x 2	60	10	25	30
Branch Saddles				
2 x 2	90	10	25	30
3 x 2	60	10	25	30
4 x 2	60	10	25	30
6 x 2	60	10	25	30
6 x 4	150	15	30	45

Warning: A.C. current only. D.C. current can result in damage to processor.
Times show above are based upon Manufacturer's recommendations and are not additive.
[1]*Clamping of fittings is not always required. Refer to Spec. 3.24, Sheet 4 for direction related to clamping.*

TABLE B: Innogaz

Fitting (inches)	Fusion Times (sec)	Clamped Cooling Time (min)[1]	Pressurized / Tapping Time (min)	Rough Handling Time (min)
Couplings/Endcaps				
1/2 CTS	17	3	15	15
1/2 IPS	45	3	15	15
3/4 IPS	27	6	15	15
1 CTS	29	6	15	15
1 IPS	37	6	15	15
1-1/4 IPS	46	6	20	20
2 IPS	85	10	20	20
3 IPS	120	8	30	30
4 IPS	160	10	30	30
6 IPS	300	14	40	40
Reducers				
3/4 x ½	23	4	15	15
1 x ½	20	4	15	15
1 x ¾	27	5	15	15
2 x 1-1/4	65	10	15	15
Tapping Tees				
1-1/4 IPS	28	10	20	20
2 IPS	70	10	20	20
3 IPS	70	10	20	20
4 IPS	70	10	20	20
6 IPS	70	10	20	20
WB HV Tapping Tees				
2 x 1-1/4; 2 x 2	70	10	25	25
3 x 1-1/4; 3 x 2	70	10	25	25
4 x 1-1/4; 4 x 2	150	16	25	25
6 x 1-1/4; 6 x 2	150	16	25	25

Warning: A.C. current only. D.C. current can result in damage to processor.
Times show above are based upon Manufacturer's recommendations and are not additive.
[1]*Clamping of fittings is not always required. Refer to Spec. 3.24, Sheet 4 for direction related to clamping.*

TABLE C: IPEX/Friatec/Frialen

Fitting (inches)	Fusion Times (sec)	Clamped Cooling Time (min)[1]	Pressurized Time (min) ≤80 PSI	Pressurized / Rough Handling Time (min) > 80 PSI
Couplings/Endcaps				
1/2 CTS	27	5	8	10
1/2 IPS	28	5	8	10
3/4 IPS	28	5	8	10
1 CTS	28	5	8	10
1 IPS	28	5	8	10
1-1/4 IPS	34	10	15	25
2 IPS	54	10	15	25
3 IPS	100	10	30	40
4 IPS	151	10	30	40
6 IPS	440	20	60	75
Reducers				
3/4 x ½	28	5	8	10
1 x ½	28	5	8	10
1 x ¾	28	5	8	10
2 x 1-1/4	54	10	15	25
Repair Clamps				
3 IPS	100	10	30	40
4 IPS	151	10	30	40
6 IPS	440	20	60	75
Tapping Tees	**Fusion Times (sec)**	**Before Pressurizing via Outlet (min)**	**Before Tapping (min)**	
1-1/4 IPS	34	15	20	
2 IPS	54	15	20	
3 IPS	100	20	30	
4 IPS	151	20	30	
6 IPS	440	30	45	

Warning: A.C. current only. D.C. current can result in damage to processor.
Times show above are based upon Manufacturer's recommendations and are not additive.
[1]Clamping of fittings is not always required. Refer to Spec. 3.24, Sheet 4 for direction related to clamping.

TABLE D: Jameson

Fitting (inches) Insertion Tap Tee	Fusion Times (sec)	Clamped Cooling Time (min)	Pressurized / Tapping Time (min)	Rough Handling Time (min)
2 x 1	90	25	25	10
4 x 1	120	25	25	10
6 x 1	120	25	25	10

Warning: A.C. current only. D.C. current can result in damage to processor.
Times show above are based upon Manufacturer's recommendations and are not additive.

TABLE E: M.T. Deason

Fitting (inches)	Fusion Times (sec)[1]	Clamped Cooling Time (min)[2]	Pressurized / Tapping Time (min)	Rough Handling Time (min)
Couplings				
1/2 CTS	On Label	5	15	15
3/4 IPS	On Label	5	15	15
1 CTS	On Label	10	20	20
1 IPS	On Label	10	20	20
1-1/4 IPS	On Label	10	20	20
2 IPS	On Label	10	20	20
3 IPS	On Label	10	20	20
4 IPS	On Label	10	20	20
6 IPS	On Label	20	40	40
Endcaps				
1 CTS	On Label	5	15	15
2 IPS	On Label	10	20	20
3 IPS	On Label	10	20	20
4 IPS	On Label	10	20	20
6 IPS	On Label	10	20	20
Reducers				
3/4 x ½	On Label	5	15	15
1 x ½	On Label	5	15	15
1 x ¾	On Label	10	20	20
1-1/4 x 1	On Label	10	20	20
4 x 2	On Label	10	20	20
6 x 4	On Label	20	35	35
Tapping Tees				
1-1/4 IPS	On Label	10	25	25
2 IPS	On Label	10	25	25
3 IPS	On Label	10	25	25
4 IPS	On Label	10	25	25
6 IPS	On Label	10	25	25
WB HV Tapping Tees				
2 x 1-1/4; 2 x 2	On Label	10	25	25
3 x 1-1/4; 3 x 2	On Label	10	25	25
4 x 1-1/4; 4 x 2	On Label	10	25	25
6 x 1-1/4; 6 x 2	On Label	10	25	25

Warning: A.C. current only. D.C. current can result in damage to processor.
Times show above are based upon Manufacturer's recommendations and are not additive.
[1]*Manufacturer does not publish fusion time. Refer to the fitting label for proper fusion time.*
[2]*Clamping of fittings is not always required. Refer to Spec. 3.24, Sheet 4 for direction related to clamping.*

TABLE E: M.T. Deason Continued

Fitting (inches)	Fusion Times (sec)[1]	Clamped Cooling Time (min)[2]	Pressurized / Tapping Time (min)	Rough Handling Time (min)
Branch Saddles				
2 x 2	On Label	10	25	25
3 x 2	On Label	10	25	25
4 x 2	On Label	10	25	25
4 x 4	On Label	10	25	25
6 x 2	On Label	10	25	25
6 x 4	On Label	20	35	35
6 x 6	On Label	10	25	25
Repair Saddles				
3 IPS	On Label	10	25	25
4 IPS	On Label	10	25	25
6 IPS	On Label	10	25	25
22.5° / 45° / 90° Elbows				
1 CTS	On Label	10	30	30
2 IPS	On Label	10	20	20
3 IPS	On Label	10	20	20
4 IPS	On Label	10	20	20
6 IPS	On Label	20	40	40

Warning: A.C. current only. D.C. current can result in damage to processor.
Times show above are based upon Manufacturer's recommendations and are not additive.
[1]*Manufacturer does not publish fusion time. Refer to the fitting label for proper fusion time.*
[2]*Clamping of fittings is not always required. Refer to Spec. 3.24, Sheet 4 for direction related to clamping.*

3.25 JOINING OF PIPE - PLASTIC (POLYETHYLENE) - MECHANICAL

SCOPE:

To establish procedures to be followed in the joining and repair of plastic pipe by means of mechanical fittings and couplings in Avista's natural gas distribution systems.

REGULATORY REQUIREMENTS:

§192.271, §192.273, §192.281, §192.283, §192.285, §192.287

CORRESPONDING STANDARDS:

Spec. 2.13, Pipe Design – Plastic (Polyethylene)
Spec. 3.13, Pipe Installation – Plastic (Polyethylene) Mains
Spec. 3.16, Services
Spec. 3.18, Pressure Testing
Spec. 3.22, Joining of Pipe - Steel
Spec. 3.33, Repair of Plastic (Polyethylene) Pipe
Spec. 3.34, Squeeze-Off of PE Pipe and Prevention of Static Electricity

General

Heat fusion or electrofusion fittings should be used whenever practical to join polyethylene pipe. Company-approved mechanical couplings may be used to connect plastic pipe in repair situations and for new installations where warranted. Compression style service head adapters may be used in cases where non-cathodically protected riser replacement is impractical or in cases where prefabricated risers for plastic services are impractical or unavailable. Compression-style fittings shall be of the type designed to effectively resist pullout forces (Category 1-A, ASTM D-2513).

Mechanical fittings shall have been tested and qualified by the manufacturer under §192.281 and §192.283 prior to use as an approved fitting. Approved mechanical fittings shall utilize only gasket material compatible with plastic pipe, employ a rigid internal tubular stiffener in conjunction with the outer coupling and meet a listed specification based upon the applicable material. Approved compression-style fittings include Continental Con-Stab ID Seal fittings and RW Lyall Lycofit mechanical fittings both which meet these qualifications according to each manufacturer. Reference current manufacturer's technical information and specification data for additional supporting information.

Joining of plastic pipe by mechanical fittings shall only be performed by properly trained and qualified personnel who shall qualify initially and re-qualify annually. Persons must be re-qualified once each calendar year not to exceed 15 months. If any field mechanical joints fail during pressure testing then the individual who installed that particular fitting is no longer qualified and must re-qualify on that mechanical fitting installation procedure unless it can be shown that the joint failed due to factors that are outside of the installer's control (i.e., equipment malfunction or material flaw).

For Aldyl-A pipe, the use of RW Lyall Lycofit mechanical fittings is only allowed on 1/2-inch and 3/4-inch diameter pipe. Joining of Aldyl-A pipe larger than 3/4-inch diameter should be made using an approved electrofusion fitting.

PE valves may be installed using spigot and sleeve mechanical fittings as long as the fitting can be installed per the manufacturer's instructions. Other mechanical fittings are not approved for the installation of PE valves. Mechanical couplings or fittings shall not be re-used.

A mechanical connection shall not be made closer than 3 pipe diameters or 12 inches, whichever is greater, from a previous squeeze point. Failure to meet these separations may result in damage to the fittings or joint. Clearances from previous squeeze points shall be visually confirmed (i.e., exposed), except for new pipeline installations where the field as-built documents have not yet been submitted and the absence of previous squeeze points can be inferred with certainty. Refer to Spec 3.34 related to requirements for squeezing plastic pipe.

When making a mechanical connection if the carrier pipe becomes discolored and appears to yield during insertion of the spigot or stab end of the fitting it is recommended the installation be cut out and replaced. An alternative joining method may need to be considered during replacement.

Marking Joints

For all types of plastic joints, the qualified individual who performed the joint shall use a permanent black marker to legibly sign the pipe with their first initial and full last name and shall also mark the date of the joint.

Procedures

PROCEDURE FOR INSTALLING APPROVED SPIGOT AND SLEEVE TYPE COUPLINGS AND FITTINGS USING THE QRP-100 QUICK RATCHET PRESS TOOL (REFERENCE: LIT-LCQRP100INST-2E):

Note: The QRP-100 ratchet press is for installation of Lycofit 1/2-inch CTS and 3/4-inch IPS fittings only. Refer to the Manufacturer's Operating Instructions Manual and the manufacturer provided instruction document packaged with each fitting for further details and diagrams to supplement the following procedure.

Installation Procedure for Double Ended Couplings

1. Inspect the installation tool for proper orientation prior to installation. If there is any damage or deformation present on the tool or tool jaws utilize a different tool where these conditions do not exist.

2. Inspect the fitting for signs of damage prior to installation. Inspect the spigot barbs and metal stiffener for deformation that may indicate damage to the entire spigot. Discard the fitting if any of these conditions exist.

3. Wipe the pipe sections to be joined with a clean, dry cloth to assure there is no dirt, grease, or oil in the assembly area. Slide the completion sleeve onto the PE pipe exposing approximately 3 inches of the pipe end. Note: Completion sleeves are non-directional and can be installed onto the pipe via either end.

4. Slide the LycoRing, with the small diameter first (thin end), onto the PE pipe and position it approximately 1/2 inch further than the length of the fitting's spigot from the end of the pipe. Note: The LycoRing may be damaged if the ring is pushed over the side of the pipe.

5. Place the spigot into the ratchet tool's fixed jaw. With one hand, slide the completion sleeve onto the LycoRing until the LycoRing starts to grip the pipe. Position the pipe and completion sleeve into the ratchet tool's movable end, the spigot should be on the fixed end. Align the pipe to the spigot and push the pipe into the spigot, stopping when the pipe reached the first barb on the spigot.

6. Operate the ratchet tool and advance the pipe onto the spigot. Stop advancement when the pipe covers the last barb on the spigot. Inspect the PE pipe for signs of damage or undue stress after it has been advanced over the spigot. Note: To prevent possible damage to the PE pipe, ensure that the spigot and the completion sleeve are fully seated in the ratchet tool's fixed jaw and that the tool and the pipe/coupling alignment is square so that the pipe does not drag on the edges of the tool jaw. Do not apply lubricants to the fitting's spigot, sleeve, or the PE pipe.

7. Reverse the ratchet direction and ratchet the tool enough to pull the completion sleeve back to expose the LycoRing. Remove the LycoRing by pulling it off of the side of the pipe using the pull tab on the ring.

8. Reverse the ratchet tool's ratchet direction and advance the completion sleeve over the pipe and spigot by operating the ratchet. Stop the completion sleeve advancement when the sleeve is fully inserted over the spigot and the sleeve face is in full contact with the fitting flange. If site conditions prohibit the sleeve face from fully contacting the fitting flange resulting in a gap, there shall be at least one point of contact between the sleeve face and the fitting flange. Inspect the joint and again the PE pipe to ensure that there is no damage that may have occurred during the installation process.

9. Complete the other side of the coupling by repeating Steps 2 through 8.

10. Test the fitting per Specification 3.18, Pressure Testing.

Installing Other Lycofit Fittings

Refer to page 4 of the QRP-100 Lyco Quick Ratchet Press installation procedure in the Manufacturer's Operating Instructions Manual for Gas Operations for guidelines on the proper spigot flange location for each type of Lycofit fitting as well as the placement of the spigot flange in the ratchet tool's jaw during installation. Apply the same steps used for installing double ended couplings as specified above.

PROCEDURE FOR INSTALLING APPROVED SPIGOT AND SLEEVE TYPE COUPLINGS AND FITTINGS USING THE LHP-200 HYDRAULIC PRESS TOOL (REFERENCE: LIT-LCLHPINST Rev. 1B):

Note: The LHP-200 hydraulic press is for installation of Lycofit 1-1/4-inch, 1-1/2-inch, and 2-inch IPS fittings only. Lubricate the hydraulic tool's shafts with non-synthetic lubricant only. Refer to the Manufacturer's Operating Instructions Manual and the manufacturer provided instruction document packaged with each fitting for further details and diagrams to supplement the following procedure.

1. Inspect the hydraulic tool to ensure there is not any damage or defamation present on the tool that might compromise the integrity of the final joint.

2. Inspect the fitting for signs of damage prior to installation. Inspect the spigot barbs and metal stiffener for deformation that may indicate damage to the entire spigot. Discard the fitting if any of these conditions exist.

3. Wipe the pipe sections to be joined with a clean, dry cloth to assure there is no dirt, grease, or oil in the assembly area. Slide the completion sleeve and then the LycoRing onto the pipe so that the LycoRing is approximately 3-1/2 inches from the end of the pipe. Nest the spigot flange in the saddle of either press plate. Place the tool so that the press plate opposite of the spigot is behind the completion sleeve.

4. Slide the PE pipe over the end of the spigot and operate the hydraulic pump until the press plate is in contact with the completion sleeve. Note: Ensure the completion sleeve engages the LycoRing and that the LycoRing does not slip along the PE pipe.

5. Continue operating the hydraulic pump to move the press plate and advance the spigot into the PE pipe until the pipe covers the last barb on the spigot. Inspect the PE pipe for signs of damage or undue stress after it has been advanced over the spigot. Note: Do not apply lubricants to the fitting's spigot, sleeve, or the PE pipe.

6. Release the hydraulic pressure and allow the tool jaw to open enough to pull the completion sleeve back and expose the LycoRing. Remove the LycoRing by pulling it off of the side of the pipe using the pull tab on the ring.

7. Operate the hydraulic pump to move the press plate and advance the completion sleeve over the pipe and the spigot. Stop pumping when the sleeve face is in full contact with the fitting flange. If site conditions prohibit the sleeve face from fully contacting the fitting flange resulting in a gap, there shall be at least one point of contact between the sleeve face and the fitting flange. Inspect the joint and again the PE pipe to ensure that there is no damage that may have occurred as part of the install process.

8. Complete the other side of the coupling by repeating Steps 2 through 7.

9. Test the fitting per Specification 3.18, Pressure Testing.

PROCEDURE FOR INSTALLING APPROVED SLIP-LOCK TYPE COUPLINGS AND FITTINGS (REFERENCE: ECN 2185 Rev "L" 10/31/07, 34-6034-00):

1. Excavate the area large enough to accommodate the flexing of the pipe that is required to install the fitting. Open excavation further as necessary.

2. Verify the stab fitting is the correct size for the PE pipe. Cut the pipe so that the ends are square using a cutter approved for plastic pipe. Avoid using a hacksaw as this may result in rough ends that are difficult to chamfer.

3. Wipe the pipe sections to be joined with a clean, dry cloth to assure there is no dirt, grease, or oil in the assembly area. Inspect for scratches or gouges. If any are detected, cut again so that the last 2 to 6 inch section (depending on size) that will be inserted into the coupling has no surface defects.

4. Use the appropriate chamfering tool specified by the manufacturer, chamfer the end of the pipe to achieve a proper bevel. The chamfer permits the pipe to be stabbed without damage to the internal seals. Chamfer the pipe in the direction of the arrows on the tool for 4 to 6 turns until pipe bottoms out. If the pipe does not appear adequately chamfered, repeat the process. Keep cutting blades free of shavings.

5. Use a soft felt tip pen, crayon, or grease pencil to mark the stab depth. This measurement may be obtained by holding the pipe against the butt fusion of the coupling and marking the pipe at the end of the coupling.

6. The ends of the pipe should be free of dirt and debris. Clean or purge as necessary. Check the coupling for dirt or debris. If dirt is found in the coupling, use another to ensure proper sealing.

7. Stab the pipe into the coupling so that it bottoms out. The reference mark made in Step 5 should be within 1/8-inch from the entrance of the coupling. The coupling is now locked in place. If unable to bottom out the pipe in the coupling, replace it and begin over at step 2.

8. Test per Specification 3.18, Pressure Testing.

PROCEDURE FOR INSTALLING APPROVED COMPRESSION TYPE SERVICE HEAD ADAPTERS (REFERENCE: ECN 2172 Rev D 9/07 0000-99-1045-00):

1. If installing on existing steel riser, cut upstream end (minimum 2 feet from the bend), de-burr, and install a protective sleeve. Remove old service valve from top of riser, inspect, and clean the pipe threads as necessary.

2. If pre-building a new galvanized riser, determine proper length and location of the bend. Bend and/or cut riser to the appropriate configuration. De-burr cut end and install a protective sleeve. Refer to Specification 3.16, Services, Drawing A 34735.

3. Insert 1/2-inch CTS I.D. (5/8-inch O.D.) polyethylene pipe through the riser, leaving a 10 inch minimum length of pipe extending above the riser.

4. Insert liner over the 5/8-inch O.D. pipe and slide down into the riser casing. (Top end riser liner is optional - use if available with current supply of service head adapters).

5. Apply pipe joint compound to the riser threads. Do not over-apply.

6. Install the line shield nut on the riser casing with the compression end facing up, then tighten with a wrench.

7. Slide the seal ring over the pipe and into the line shield nut.

8. Insert service pipe onto the adapter-coupling stiffener, applying pressure to the plastic pipe until it bottoms out in the adapter coupling. Push entire assembly to the line shield nut.

9. Tighten adapter coupling until it bottoms out against the shoulder of the line shield nut.

10. Install new service valve and tighten.

11. Purge the service line and then pressurize. Check the regulator for flow and lockup. Test per Specification 3.18, Pressure Testing.

PROCEDURE FOR INSTALLING APPROVED SLIP-LOCK TYPE SERVICE HEAD ADAPTERS (i.e., "PERFECTION" TYPE):

1. Follow Steps 1 and 2 under procedures for compression type service head adapters, as appropriate.

2. Inspect the gas riser casing for burrs and damaged threads. Deburr and rethread if necessary.

3. Disconnect the service head adapter fitting from the inlet device supplied (short section of pipe nipple, threaded on one end). If the riser is already threaded, discard this short nipple. If riser is not threaded, this nipple may be welded to end of riser to provide threaded end.

4. Push the PE service line through the threaded steel nipple and/or bushing or riser casing until it extends 6 to 8 inches beyond the casing outlet.

5. Square cut the end of the PE service line and wipe clean with a dry cloth. Inspect to be sure that there are no scratches, gouges, or surface defects in the last 4 inches of the service line. If scratches or gouges are visible, cut off the defective area, and repeat steps 3 and 4.

6. Chamfer the square cut end of the PE service line with a chamfering tool recommended or supplied by the manufacturer.

7. Determine the stab depth required by checking the length of hex on the fitting body (length of hex equals the stab depth). Mark the stab depth on the PE service line with a soft marking instrument (grease pencil, etc.).

8. Stab the service head adapter fitting onto the PE service line until the service line bottoms out in the fitting. The mark on the PE service line should be within 1/8-inch from the end of the fitting. Note: Do not twist the fitting or pipe until fully stabbed.

9. Reconnect the service head adapter fitting and the inlet device. After applying pipe joint compound to the riser threads, place the assembly back on the riser threads and tighten.

10. Install the service valve and tighten.

11. Purge the service line and pressurize. Check regulator for flow and lockup. Leak test per Specification 3.18, Pressure Testing.

PROCEDURE FOR INSTALLING APPROVED WELD-ON 1201 AND 1302 STYLE STEEL PUNCH TEES WITH COMPRESSION TYPE OUTLET CONNECTION FOR PE PIPE

Note: Aspects of this procedure are related to welding the steel service tee onto a steel main. These steps are described in this procedure; however, welding shall be completed using an approved weld procedure in accordance with Specification 3.22, Joining of Pipe – Steel. Services shall be installed per Specification 3.16, Pipe Installation – Services.

1. Before installation of the service tee, confirm the punch is rated for the steel pipe to be tapped.
   a. 3/8-inch punches are rated for tapping pipe with a 0.280-inch maximum wall thickness and a 70,000-psi maximum yield strength.
   b. 1/4-inch, 1/2-inch, 3/4-inch, and 1-inch punches are rated for tapping pipe with a 0.250-inch maximum wall thickness and 65,000 psi maximum yield strength

2. Verify the compression fitting on the outlet of the tee is the correct size for the PE pipe being connected. Verify the SDR of the PE pipe matches the SDR stamped on the end of the stiffener.

3. Remove the O-ring cap, the punch, outlet seal ring, and compression nut from the service tee and place in the plastic bag in which the tee was shipped. Do not remove the splatter shield from the inlet.

4. Remove the coating on the mainline and thoroughly clean off any residual rust, dirt, etc.…in the area where the service tee is to be welded.

5. Weld the service tee onto the main. Note: the service tee must be cool to the touch before re-inserting the punch (removed during Step 3).

6. Once the service tee is installed on the main, the PE service can be connected to the tee one of two ways as follows:
   a. Install the compression nut and seal ring on the outlet of the tee. Do not tighten the compression nut.
   -Or-
   b. Slide the compression nut and seal ring onto the PE pipe.

7. Cut the end of the PE service pipe square, deburr inside and outside, and clean thoroughly to assure there is no dirt, grease, oil etc. on the pipe in the assembly area.

8. Mark the appropriate stab length on the pipe.
   a. For 3/8-inch OD, 5/8-inch OD, 7/8-inch OD and 1/2-inch IPS:
   Stab length = 1-11/16”

   b. For 3/4-inch IPS, 1-inch IPS, 1-1/4-inch IPS, and 1-1/8-inch OD:
   Stab length = 1-7/8-inch

9. Insert the PE pipe into the tee until it bottoms in the fitting. Note: Prior to completing the service line connection be sure to install a stress-relieving sleeve on the service line that will help protect the rigid steel to PE transition per the requirements in Spec 2.13 – “Joining of Plastic Pipeline Components”. Also, refer to Drawing A-37169 in Spec 3.16 for an example of a sleeve installation on a steel tee with PE transition.

10. Tighten the compression nut until it bottoms on the shoulder of the tee (metal to metal). The stab length line should be no more than 3/16 of an inch from the face of the compression nut. If the stab length line is more than 3/16 of an inch from the face of the compression nut, disassemble the joint and repeat Steps 6 through 10.

11. Prior to tapping the tee fitting to allow gas to the service line, pressure test the tee and new outlet piping as applicable per Specification 3.18, Pressure Testing.

12. Insert the punch in the service tee and turn clockwise by hand to avoid cross threading. Apply proper lubricant to the punch threads and tip prior to tapping. Acceptable lubricants include thread cutting oil, tapping fluid, or tapping grease.

13. Use a standard hex wrench (see note below) or a ratchet wrench with Continental drive key and bushing to make the tap. It is important to ensure retention of the coupon by running the punch all the way down until the punch seats on the main.
   Continental drive key and bushing information:
   a. 1/2-inch body tees use 23-3691-00 Hex Drive Key, Bushing, and Socket Adapter
   b. 3/4-inch body tees use 23-3692-00 Hex Drive Key, Bushing, and Socket Adapter

   Note: The manufacturer has approved the use of a standard hex wrench or the Continental drive key and bushing.

14. To allow gas to the service line, back the punch valve up until it protrudes 2 to 3 threads above the top of the tee.

15. Insert the hex drive of the O-ring plug cap into the socket of the punch valve and run the unit down until it is leak tight. Take care as the threads of the O-ring plug engage the threads of the tee body to prevent cross threading.

16. As a best practice, consider creating notes and/or marking the tee (e.g., tape, marker, etc.) to keep track of whether the tee has been tapped out.

PROCEDURE FOR INSTALLING APPROVED WELD-ON STYLE 1201 AND 1302 STYLE STEEL PUNCH TEES WITH SPIGOT AND SLEEVE TYPE OUTLET CONNECTION FOR PE PIPE

Note: Aspects of this procedure are related to welding the steel service tee onto a steel main. These steps are described in this Specification; however, welding shall be completed using an approved weld procedure in accordance with Specification 3.22, Joining of Pipe – Steel. Services shall be installed per Specification 3.16, Pipe Installation – Services.

1. To install the steel service tee, follow steps 1-5 in the separate procedure listed above in this specification (Procedure for Installing Approved Weld-On 1201 and 1302 Style Steel Punch Tees with Compression Type Outlet Connection for PE Pipe).

2. Once the service tee is connected to the main install the outlet pipe as described in the separate procedure listed in this specification (use the procedure for the QRP-100 ratchet press tool for 1/2-inch CTS and 3/4-inch IPS fittings or the procedure for the LHP-200 hydraulic press tool for 1-1/4-inch IPS and 2-inch IPS fittings). Note: Prior to completing the service line connection be sure to install a stress-relieving sleeve on the service line that will help protect the rigid steel to PE transition per the requirements in Spec. 2.13 – "Joining of Plastic Pipeline Components". Also, refer to Drawing A-37169 in Spec. 3.16 for an example of a sleeve installation on a steel tee with PE transition.

3. Prior to tapping the tee fitting to allow gas to the service line, pressure test the tee and new outlet piping as applicable per Specification 3.18, Pressure Testing.

4. Once the service is connected to the outlet of the service tee, tap the tee to complete the service following steps 11-15 in the separate procedure listed above in this specification (Procedure for Installing Approved Weld-On 1201 and 1302 Style Steel Punch Tees with Compression Type Outlet Connection for PE Pipe)

5. As a best practice, consider creating notes and/or marking the tee (e.g., tape, marker, etc.) to keep track of whether the tee has been tapped out.

PROCEDURE FOR INSTALLING APPROVED PE COMPRESSION X WELD END ADAPTER COUPLINGS (SOMETIMES REFERRED TO AS THE "BUTTON" FITTING) (REFERENCE: ECN 2625 REV "D" 08/29/14):

Note: Step 2 of this procedure is related to welding the coupling. Welding shall be completed using an approved weld procedure in accordance with Specification 3.22, Joining of Pipe – Steel.

1. Before welding the adapter coupling, remove the seal ring and compression nut from the coupling body and place in the plastic bag in which the coupling was shipped.

2. Weld coupling body following an approved welding procedure.

3. Allow welded coupling to cool to ambient temperature before installing PE pipe.

4. After the weld has cooled to ambient temperature, the PE service can be connected to the fitting one of two ways as follows:

   a. Install the seal ring and compression nut. Do not tighten the compression nut.

   -Or-

   b. Slide the compression nut and seal ring onto the PE pipe.

5. Verify that the coupling is the correct size for the polyethylene (PE) pipe. Verify the SDR (or wall thickness) of the pipe matches the SDR (or wall thickness) stamped on the end of the stiffener.

6. Cut PE pipe ends square, deburr inside and outside, clean thoroughly to assure there is no dirt, grease, oil, etc. on assembly area of pipe.

7. Mark the appropriate stab length on the pipe.
   a. For 3/8" OD, 5/8" OD, 7/8" OD and ½" IPS:
   Stab length = 1-11/16"

   b. For ¾" IPS, 1" IPS, 1-1/4" IPS, and 1-1/8" OD:
   Stab length = 1-7/8"

8. Insert the PE pipe until it bottoms in the fitting. Note: Prior to completing the service line connection be sure to install a stress-relieving sleeve on the service line that will help protect the rigid steel to PE transition per the requirements in Spec. 2.13 – "Joining of Plastic Pipeline Components". Also, refer to Drawing A-37169 in Spec. 3.16 for an example of a sleeve installation on a steel tee with PE transition.

9. Tighten compression nut until it shoulders against the outlet. The line marked for stab length should be no more than 3/16 of an inch from face of nut. If it is not, disassemble the joint and reinstall following steps 5 through 9.

PROCEDURE FOR INSTALLING APPROVED BOLT-ON TYPE MECHANICAL TEES WITH SPIGOT AND SLEEVE TYPE OUTLET CONNECTION (REFERENCE: LIT-LCTTINST Rev. 1E):

Note: Refer to the Manufacturer's Operating Instructions Manual and the manufacturer provided instruction document packaged with each fitting for further details and diagrams to supplement the following procedure.

1. Thoroughly clean the entire pipe surface where the tapping tee will be installed. Do not place the saddle O-rings over gouges or scratches on the pipe surface. If a scratched surface is unavoidable, refer to the procedure below for repairing scratches prior to tee installation.

2. Remove the tapping tee from the bag. Take care not to allow dirt to contaminate the O-rings or to enter the cutter cavity. Position the top half of the tapping tee to the main and align the tee's outlet spigot in a horizontal position and press the tee onto the pipe surface. Align the bottom half of the tee with the bolt holes in the top half. Press the halves together evenly leaving an equal gap between the halves on both sides. Spin the four flange nuts onto the bolt studs until hand tight (nuts should spin freely). Note: It is preferred the service tee be installed on the top of the main with the spigot outlet in the horizontal position, however it is acceptable to rotate the tee as much as 90-degrees up or down from horizontal.

3. Tighten the nuts using a nut driver. Tighten the nuts one turn at a time in a crisscross pattern until the corners of the top and bottom flanges are brought together (approximately 60 to 95 in-lbs). Do not over tighten.

4. Install the outlet pipe as described in the separate procedure listed in this specification (use the procedure for the QRP-100 ratchet press tool for 1/2-inch CTS and 3/4-inch IPS fittings or the procedure for the LHP-200 hydraulic press tool for 1-1/4-inch IPS and 2-inch IPS fittings).

5. Pressure test the tee and new outlet piping as applicable per Specification 3.18, Pressure Testing.

6. Remove the tapping tee cap. Be careful to keep dirt out of the cap and cutter area. Insert a 3/8-inch Lyall manufactured Lyco hex drive tool into the cutter and advance the cutter down until contact has been made with the cutter stop. Do not continue to advance the cutter once contact has been made with the stop. Unscrew the cutter until the top of the cutter is approximately 1/4 inch below the rim of the tapping tee top.

7. Inspect the cap for cleanliness and seating of the O-ring in the groove. Inspect the tapping tee top rim and threads for cleanliness and cutter position. Re-install the cap and tighten by hand until the cap contacts the stop. Do not use a wrench to tighten the cap.

8. As a best practice, consider creating notes and/or marking the tee (e.g., tape, marker, etc.) to keep track of whether the tee has been tapped out.

9. Pressurize and soap test tapping tee cap, saddle, and outlet connections to assure proper assembly.

10. During backfill, ensure that the earth is fully compacted under the tapping tee, its outlet connection, and the adjacent PE pipe.

PROCEDURE FOR INSTALLING APPROVED BOLT-ON TYPE MECHANICAL TEES WITH SLIP-LOCK TYPE OUTLET CONNECTION (REFERENCE: ECN 2185 Rev "L" 10/31/07, 34-6034-02):

Mounting surface must be clean and free of cuts and scratches when possible. If a scratched surface is unavoidable, refer to the procedure below for repairing scratches prior to tee installation.

1. Place top and bottom half of saddle on main. Insert bolts and tighten in a crisscross pattern, taking care not to rotate saddle on the main. A thread lubricant such as "Select Unyte" should be used on the bolts. Tighten the bolts until the flanges of the saddle come together along the outer edge. The flanges of the saddle may not come together next to the pipe. Bolt torque should not exceed 120 inch-pounds. Note: It is preferred the service tee be installed on the top of the main with the spigot outlet in the horizontal position, however it is acceptable to rotate the tee as much as 90-degrees up or down from horizontal.

2. Connect service line to tee following the procedures for the slip-lock type couplings outlined in this specification.
3. Pressure test the tee and new outlet piping as applicable per Specification 3.18, Pressure Testing.

4. For tapping the tee, remove O-ring and cap, then insert approved drive key into punch.

5. Screw punch down until stop on drive key contacts the top of the tee. The tap is now complete.

6. To allow flow through the service, back punch up until the top of the punch is flush with top of tee. It is important that the punch does not protrude above the tee.

7. Replace O-ring and cap. Screw down hand tight. Do not use wrenches on O-ring cap.

8. As a best practice, consider creating notes and/or marking the tee (e.g., tape, marker, etc.) to keep track of whether the tee has been tapped out.

9. Pressurize and soap test tapping tee cap, saddle, and outlet connections to assure proper assembly.

PROCEDURE FOR REMOVING SCRATCHES FROM PE PIPE PRIOR TO THE INSTALLATION OF A MECHANICAL TAPPING TEE:

This procedure shall be used when:

1. The surface of the PE pipe where the tee will be installed contains scratches that can cause an inadequate sealing surface between the pipe and the tee, and

2. Installing the tee in an alternative non-scratched location is not practical.

This procedure shall not be used if the depth of any scratch exceeds 10 percent of the wall thickness of the pipe. If a scratch deeper than 10 percent of the wall thickness of the pipe is present, either replace the section with new pipe or repair the pipe using an approved repair fitting, per Specification 3.33, Repair of Plastic (Polyethylene) Pipe.

Scratch Repair Procedure:

1. Thoroughly clean the entire pipe surface where the mechanical fitting will be installed. An alcohol wipe is the preferred method for cleaning the pipe surface.

2. Mark the edges of proposed location of the mechanical fitting with a marker. Extend sanding of the surface a minimum of 1/2” beyond the edges of the fitting to ensure the entire area where the fitting contacts the pipe is repaired and to allow for proper visual inspection of the repair.

3. Use 80-grit emery cloth and sand the surface of the pipe evenly where the fitting will be installed until most of the scratches are removed. If the scratch depth is such that the use of 80 grit emery cloth will cause further damage to the pipe surface, this step may be skipped and may proceed to Step 4. Do not remove more than 10 percent of the wall thickness of the pipe. Do not use a scraper or peeler to remove the scratches.

4. Use 180-grit emery cloth and sand the surface until no scratches remain.

5. Use 280-grit emery cloth and sand the surface once more to prepare the final surface.

6. Wipe the sanded surface clean with an alcohol wipe.

7. Continue with the Bolt-on Mechanical Tee procedure in this specification.

PROCEDURE FOR INSTALLING 1/2 INCH AND 3/4 INCH ABANDONMENT NUTS ON CONTINENTAL STEEL TO PE SERVICE TEE (REFERENCE: ECN 2620 REV “E” 07/22/14):

1. Remove the service tee cap. Screw down the punch completely to shut off gas flow.

2. Remove the existing compression nut and seal ring and discard.

3. Cut the PE service line as close as possible to the end of the stiffener. Do not remove the remaining pipe from the stiffener.

4. Assemble the abandonment nut with a new seal ring onto the outlet of the service tee. Tighten the abandonment nut until it contacts the shoulder of the service tee.

5. Unscrew (back out) the service tee punch to allow gas pressure through the tee to the abandonment nut and then reinstall the service tee cap. Soap test the joints for leaks.

3.3 REPAIR OF DAMAGED PIPELINES

3.32 REPAIR OF STEEL PIPE

SCOPE:

To establish uniform procedures for determining appropriate repairs based on extent of damage to steel distribution and transmission pipelines. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

REGULATORY REQUIREMENTS:

§192.241, §192.243, §192.245, §192.309, §192.485, §192.627, §192.711, §192.712, §192.713, §192.715, §192.717, §192.719, §192.723, §192.725

OTHER REFERENCES:

ASME B31G – Manual for Determining the Remaining Strength of Corroded Pipelines

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design – Steel
Spec. 3.12, Pipe Installation – Steel Mains
Spec. 3.13, Pipe Installation – Plastic (Polyethylene) Mains
Spec. 3.17, Purging Pipelines
Spec. 3.18, Pressure Testing
Spec. 3.22, Joining of Pipe – Steel
Spec. 3.44, Exposed Pipe Evaluation
Spec. 4.12, Safety-Related Conditions
GESH Section 4 – Emergency Procedures, "Temporary Control of Escaping Gas"

STEEL REPAIR REQUIREMENTS:

General

Each operator shall take necessary measures prior to beginning repairs to assure that the public and Company personnel are protected from danger. Typically, repairs should be made as soon as practical, depending on the degree of the hazard.

Welding equipment shall not be used where an uncontrolled gas-air mixture exists. Prior to welding, cutting, or other hot work in or around a structure or area including a trench containing gas facilities, a thorough check shall be made with a combustible gas indicator (CGI). CGI readings shall continuously be taken while repairs are being made until the area is made safe.

Welded repairs shall be performed by qualified welders using a qualified welding procedure. Refer to Specification 3.22, Joining of Steel Pipe.

Whenever a previously buried pipeline is exposed, an Exposed Piping Inspection Report form (Form N-2534) shall be completed. Refer to Specification 3.44, Exposed Pipe Evaluation, for more information.

Only those methods of repair as detailed in this standard are approved as permanent repairs to welded steel mains. When a repair cannot be made in conformance with the conditions of this standard, the section of defective pipe shall be replaced with a new piece of pipe.

The most appropriate method of repair permitted shall be selected from the proper "Steel Repair Selection Chart" based on operating pressure and stress (refer to the attached charts).

If a segment of steel pipeline is repaired by cutting out the damaged portion, the replacement pipe must be tested to the pressures required for a new line installation and specific information about the pressure test and pipe material shall be documented on the Pre-Tested Pipe Documentation form (N-2743). Refer to Specification 3.18, Pressure Testing, "Recordkeeping."

Regardless of which method of repair is used, exposed pipe must be cleaned, have mastic reapplied or be recoated with an approved pipeline primer, and taped according to the manufacturer's instructions and per Specification 3.12, Pipe Installation – Steel Mains.

Corrosion damage shall be measured by a device such as a pit gauge to determine the depth of pitting.

Whenever exposed, underground Dresser-style or other steel mechanical compression fittings shall be cut out or canned (barreled). A Cathodic Protection Technician shall be contacted to verify that the fitting is not being used as an isolation point. Cutting out or barreling may inadvertently create a problem between two separated cathodic protection systems so additional steps may be necessary before removing or barreling the fitting.

Monitoring of Pressure

Gas personnel performing work on pipelines and facilities that could result in loss of pressure or overpressure to the system shall install accurate pressure gauges upstream and downstream of the work site. The pressure gauges shall be continuously monitored as long as is necessary, so that personnel can respond accordingly, if system pressures are greatly affected.

Additionally, there may be times when merely monitoring downstream pressure may not be sufficient to prevent customer outages without further action. It may be necessary during warm days or periods of low gas use to intentionally draw down the pressure of the downstream system and observe it to confirm the existence of a looped system prior to altering the system or leaving the area. Consult Gas Engineering for recommendations prior to altering any system's pressure. It may also be necessary to install a temporary bypass if a system is not looped or if the pipeline work could result in loss of pressure to the system. Refer to Specification 3.12, Pipe Installation – Steel Mains for temporary bypass details and requirements.

Any loss of pressure that may have extinguished pilots or that may have affected the normal operation of the customer's gas equipment shall be treated as an outage and the procedures followed as outlined in the GESH, Section 5, Emergency Shutdown and Restoration of Service.

Service Lines

When a service line has been disconnected for repair, refer to "Reinstating Service" in Specification 3.18, Pressure Testing.

Grinding

When grinding to eliminate a defect, care must be used to remove the entire defect. A 60 grit sanding wheel should be used. Such grinding shall be smoothly contoured to the pipe to eliminate all possible points of stress concentration. The wall thickness shall not be ground to less than what is required for the design pressure of the pipeline.

Arc burns on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS must have a remaining wall thickness that is equal to either the minimum required by the tolerances in the specification to which the pipe was manufactured or the nominal wall thickness required for the design pressure of the pipeline.

Grinding and Fill Welding

When grinding and fill welding, the repair area must be ground clean. The fill weld metal shall penetrate the base material. The surface of the finished repair weld shall be ground smooth to the contour of the pipe on lines operating over 100 psig. Arc welding is required for all repairs.

Patching

Patches shall have a wall thickness greater than or equal to the pipe they are being installed on, have rounded corners, and be designed to operate at less than 20 percent SMYS at the pipeline MAOP. Contact Gas Engineering for assistance determining the proper patch specifications.

Sleeving

Sleeve design and testing shall be similar to patch design but must be full encirclement and should feature a backing strip. Sleeve length should extend a minimum of 6 inches on each end of defect. Refer to the Specification 3.22, Joining of Steel Pipe, Appendix A, for specific weld procedures for sleeve installation.

Mueller Save-A-Valve Nipple or Equivalent

A Mueller Save-A-Valve nipple or equivalent fitting may be used to repair an individual corrosion pit (either leaking or non-leaking) where the diameter of the pit at the surface of the pipe is less than the inside diameter of the nipple. The weld shall be visually limitations when using the Mueller Save-A-Valve or equivalent type fittings.

Canning (Barreling)

Gas main repair cans may be used for repairs on pipelines with a design pressure which produces a hoop stress of less than 20 percent SMYS. The can shall be designed and fabricated using approved pipe and fittings (use of plate shall not be allowed) and pressure tested to 1.5 times the MAOP. Canning shall not be used on pipelines operating at pressures greater than 60 psig without concurrence of Gas Engineering. Canning repairs on systems operating above 60 psig shall be designed by Gas Engineering.

Tapping and Plugging Procedures

A copy of the manufacturer's detailed tapping and plugging procedures for the type(s) of equipment utilized in each construction area must be kept at locations where tapping and plugging activities are conducted. Both the tapping and plugging procedures should be reviewed periodically to ensure that responsible personnel are familiar with operating and maintenance of tapping and line stopping equipment. Additionally, these procedures shall be reviewed as part of an equipment check and tailboard in the field prior to tapping. Only qualified individuals shall perform tapping and plugging operations unless an individual is being observed on a one to one basis.

(Refer to Specification 3.12, Pipe Installation - Plastic, "Pipe Coupon Retention Procedures," for further guidance on retention of pipe coupons for transmission and high pressure mains.)

Replace Segment of Pipe

Remove the section of pipe containing the defect from service and purge section as necessary. Remove cylindrical barrel section of pipe containing defect by making two circumferential cuts. Replacement pipe shall be of equal or better material based on the system design pressure and design requirements of Specification 2.12, Pipe Design-Steel. Pipe used to replace a segment of pipeline must be pressure tested to the requirements of new main and to meet the MAOP of the pipeline system being repaired. Refer to Specification 3.18, Pressure Testing.

Pre-Tested Steel Pipe

When making a repair as a result of third party damage or material failure and it is not possible or practicable to test the section of pipe being replaced, pre-tested pipe shall be used. A Pre-Tested Pipe Documentation form (N-2743) shall be filled out and kept at the local office for all pre-tested pipe.

Once the pipe is installed, a copy of the Pre-Tested Pipe Documentation form must be kept for the life of facility with the project file (not at the warehouse with the uninstalled pipe records). If pre-tested steel pipe is used to make a repair on high pressure facilities, then a copy of the Pre-Tested Pipe Documentation form and pressure test chart must be sent to Gas Engineering to include in the project file. The tested pipe shall be segregated from the rest of the pipe stock and identified as pre-tested pipe. The pipe should be periodically inspected and remarked as necessary to indicate its status. Refer to Specifications 3.12 and 3.13 for further guidance on Storage and Handling of pipe and Specification 3.18 regarding pre-installation testing.

Dents (Pipe Distortion)

Distortion or denting may be defined as a depression, which produces a gross disturbance in the curvature of the pipe wall (as opposed to a scratch or gouge, which reduces the pipe wall thickness). The depth of a dent shall be measured as the gap between the lowest point of the dent and the prolongation of the original contour of the pipe in any direction. Dents on a longitudinal or circumferential weld operating at less than 20 percent SMYS can be treated the same as a dent, which does not affect a weld. Dents in a pipeline with a MAOP equal to 20 percent SMYS, or more, which affect the longitudinal or circumferential weld shall be removed or repaired by a method that reliable engineering tests and analysis show can permanently restore the serviceability of the pipe. A dent with mechanical damage is more severe than a dent or mechanical damage alone.

Repair Clamps and Sleeves

Percent distortion shall be defined as the ratio of the depth of the dent to the actual diameter of the pipe times 100. Distortion exceeding the limitations in the “Steel Repair Selection Charts” shall be removed.

Repair clamps shall only be used when it is not practical to use the repair methodologies as instructed in the “Steel Repair Selection Charts”. Only approved repair clamps and sleeves may be used (refer to the Foreword of this manual for what is considered “approved”). Unless detailed in the following specifications, the manufacturer’s installation procedures shall be followed. Repair clamps should be temporary unless they are welded in place and meet the required ANSI ratings of the main. An anode shall be cad welded to all permanent clamps and the clamps coated in mastic. Contact the Cathodic Protection department to determine proper size of anode.

Transmission Lines

Repairs to transmission pipelines should follow Section 6 (Remediation of Anomalous Conditions) of the Transmission Integrity Management Plan (TIMP). None of Avista's transmission pipelines currently have the capability to find anomalies using 'smart pig' In-Line-Inspection (ILI) tooling, so discovery of an anomalous condition would require exposure of the pipe and visual examination. As a best practice, any repairs should be made immediately or within the one-year timeframe as if it were in an HCA.

Each segment of transmission pipe with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline must be replaced. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion. A segment of transmission pipe with localized corrosion pitting to a degree where leakage might result shall be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on actual remaining wall thickness and calculated and documented in accordance with TIMP Evaluation and Remediation Practice (E&RP) #13 – *Analysis of Predicted Failure Pressure*.

All repair methods shall be determined by Gas Engineering and must be performed using pipe and material properties that are documented in traceable, verifiable, and complete (TVC) records. If documented data required for any analysis, including predicted failure pressure for determining MAOP, is not available, it must be obtained in accordance with TIMP Section 14.3 – *Verification of Pipeline Material Properties and Attributes*.

The operating pressure must be at a safe level during repair operations. Consideration should be given to lowering the operating pressure to less than 80% of the setpoint when the anomalous condition was discovered, until the repair can be completed, or in accordance with TIMP Section 6.7.2.

Testing of repairs made by welding shall be visually inspected to ensure that the welding is performed in accordance with the welding procedure and that the acceptability of a nondestructive weld is in accordance with Section 9 of API 1104 per §192.241.

Under the following conditions, visual examinations of the welds may be substituted for radiographic examinations:

1. The pipe has a nominal diameter of less than 6 inches regardless of stress level; or
2. The pipeline operates at a pressure of less than 40 percent of SMYS and the welds are so limited that radiographic testing is impractical.

A waiver from Gas Engineering should be obtained to avoid NDT examination in either case.

Leak Repair and Residual Gas Checks

After a leak is repaired, it shall be checked for residual gas while the excavation is still open by a person qualified in Avista Side Leak Investigation. The perimeter of the leak area shall be bar holed and checked with a combustible gas indicator in percent gas mode to determine if repairs were adequate and if there is migration from a secondary leak. A minimum of four bar hole readings shall be taken at equally spaced points at the perimeter of the excavation or from within the bell hole prior to backfill to fulfill this requirement.

If readings indicate the presence of gas, the perimeter shall be expanded, and additional bar hole readings taken until the extent of the leak is found and documented down to less than 0.05 percent gas in air. If the discovery of gas is determined to be a second leak, a new order shall be established by contacting the Avista Call Center. Bar hole locations shall be mapped as appropriate.

Repairs to damaged service lines require additional leak survey actions. Refer to “Service Line Leak Survey” in Specification 5.11, Leak Survey for more information.
Whenever a pipeline is exposed, whether steel or PE, an Exposed Piping Inspection Report form (Form N-2534) shall be completed. Further detail regarding the use of the Exposed Piping Inspection Report form is detailed in Specification 3.44, Exposed Pipe Evaluation.

Pressure test information is required if a section of pipe is replaced. It can either be tested in the field or by using pretested pipe. Refer to Specification 3.18, Pressure Testing.

Recordkeeping

Records and maps of repairs performed shall be retained for the life of the facilities.

Specific Repair Methods

The following three Steel Repair Selection Charts detail the repair methodology to be used for damaged steel pipelines.

STEEL REPAIR SELECTION CHART FOR PIPELINES WITH AN MAOP OF 100 PSIG OR LESS

TYPE OF DEFECT		
1. MECHANICAL DAMAGE: NOTCHES, SCRATCHES, GOUGES, AND HOLES		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. DENT LESS THAN 10% DISTORTION	1. NO REPAIR REQUIRED	NO NOTCHES, SCRATCHES, GOUGES OR GROOVES IN DENT.
B. DENT-MORE THAN 10% DISTORTION (1/2” FOR 4-1/2” O.D. & SMALLER)	1. SLEEVING OR CANNING	DENT MUST NOT PREVENT PROPER FIT UP.
	2. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.
C. NOTCH, SCRATCH, GOUGE, GROOVE-LESS THAN 50% OF PIPE WALL THICKNESS	1. GRINDING	LESS THAN 10% DISTORTION OR DENT (1/2" FOR 4-1/2" O.D. & SMALLER). PIPE WALL NOT TO BE REDUCED TO LESS THAN 50% OF ORIGINAL NOMINAL WALL THICKNESS.
D. NOTCH, SCRATCH, GOUGE, GROOVE-MORE THAN 50 PERCENT OF PIPE WALL THICKNESS	1. GRINDING AND WELDING	LESS THAN 10% DISTORTION OR DENT (1/2" FOR 4-1/2" O.D. & SMALLER. REPAIR NOT TO EXCEED 1/4 CIRCUMFERENCE OF PIPE NOR 5 SQUARE INCHES. NOT MORE THAN ONE REPAIR PER FOOT OF PIPE LENGTH.
	2. PATCHING	LESS THAN 10% DISTORTION OR DENT (1/2" FOR 4-1/2" O.D. & SMALLER. PATCH NOT TO EXCEED 1/2 PIPE CIRCUMFERENCE. LENGTH NOT OVER 10 PIPE DIAMETERS ON PIPE OVER 8-5/8 O.D. A MINIMUM OF 3" CLEARANCE BETWEEN PATCHES. PATCH SHALL HAVE ROUNDED CORNERS, WALL THICKNESS SHALL MEET OR EXCEED CARRIER PIPE, AND OPERATE AT LESS THAN 20% SMYS AT PIPELINE MAOP.
	3. SLEEVING OR CANNING	DENT MUST NOT PREVENT PROPER FIT UP.
	4. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.
E. HOLE	1. PATCHING	PATCH NOT TO EXCEED 1/2 PIPE CIRCUMFERENCE. LENGTH NOT OVER 10 PIPE DIAMETERS ON PIPE OVER 8-5/8 O.D. A MINIMUM OF 3" CLEARANCE BETWEEN PATCHES. PATCH SHALL HAVE ROUNDED CORNERS, WALL THICKNESS SHALL MEET OR EXCEED CARRIER PIPE, AND OPERATE AT LESS THAN 20% SMYS AT PIPELINE MAOP.
	2. SLEEVING OR CANNING	MATERIAL USED TO FABRICATE SLEEVE OR CAN MUST NOT EXCEED 20% SMYS AT THE PIPELINE MAOP.
	3. LEAK CLAMP	PRESSURE RATING OF CLAMP MUST MEET OR EXCEED THE PIPELINE MAOP.
	4. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.

TYPE OF DEFECT		
2. CORROSION DAMAGE, TO INCLUDE BOTH GENERAL CORROSION AND LOCALIZED CORROSION PITTING (as measured with a pit gauge)		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. DEPTH LESS THAN 50% OF PIPE WALL THICKNESS	1. NO REPAIR REQUIRED	CLEAN AND RECOAT BURIED PIPE OR REPAINT ABOVE GRADE PIPE.
B. DEPTH OVER 50% OF PIPE WALL THICKNESS BUT LESS THAN 80%-NO LEAKAGE.	1. GRINDING AND WELDING	REPAIR NOT TO EXCEED ¼ CIRCUMFERENCE OF PIPE NOR 5 SQUARE INCHES. NOT MORE THAN ONE REPAIR PER FOOT OF PIPE LENGTH.
	2. PATCHING	PATCH NOT TO EXCEED 1/2 PIPE CIRCUMFERENCE. LENGTH NOT OVER 10 PIPE DIAMETERS ON PIPE OVER 8-5/8 O.D. A MINIMUM OF 3" CLEARANCE BETWEEN PATCHES. PATCH SHALL HAVE ROUNDED CORNERS, WALL THICKNESS SHALL MEET OR EXCEED CARRIER PIPE, AND OPERATE AT LESS THAN 20% SMYS AT PIPELINE MAOP.
	3. SLEEVING OR CANNING	NO LIMITATIONS.
	4. MUELLER SAVE-A-VALVE NIPPLE (OR EQUIVALENT FITTING)	2" MAXIMUM SIZE NIPPLE.
	5. LEAK CLAMP	
C. DEPTH 80% OF PIPE WALL THICKNESS OR MORE-INCLUDING LEAKING CORROSION PITS	1. PATCHING	SAME AS 2.B.2.
	2. SLEEVING OR CANNING	NO LIMITATIONS.
	3. MUELLER SAVE-A-VALVE NIPPLE (OR EQUIVALENT FITTING)	2" MAXIMUM SIZE NIPPLE.
	4. LEAK CLAMP	
	5. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED SHOULD BE REMOVED.
D. EXTENT OF THE CORROSION IS SUCH THAT THE REPAIRS IN A, B & C ARE NOT FEASIBLE.	1. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED SHOULD BE REMOVED.

TYPE OF DEFECT		
3. LEAKS IN WELD OR PIPE WELD SEAM		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. ALL	1. PATCHING	SAME AS 2.B.2. EXISTING FACILITIES ONLY.
	2. SLEEVING OR CANNING	EXISTING FACILITIES ONLY
	3. MUELLER SAVE-A-VALVE NIPPLE (OR EQUIVALENT FITTING)	2" MAXIMUM SIZE NIPPLE, FOR EXISTING FACILITIES ONLY.

TYPE OF DEFECT		
4. NON-LEAKING CRACKS OR DEFECTS IN WELD OR PIPE WELD SEAM		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. ANY LONGITUDINAL WELD CRACK GREATER THAN 2" LONG, A BRANCH OR CIRCUMFERENTIAL WELD CRACK THAT IS MORE THAN 8% OF WELD LENGTH, OR A CRACK THAT PENETRATES EITHER THE ROOT OR SECOND BEAD	1. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED. IF NOT FEASIBLE TO TAKE MAIN OUT OF SERVICE, INSTALL SLEEVE.
B. ANY LOGINTUDINAL WELD CRACK LESS THAN OR EQUAL TO 2" LONG, A BRANCH OR CIRCUMFERENTIAL WELD CRACK LESS THAN OR EQUAL TO 8% OF WELD LENGTH, OR OTHER DEFECTS	1. GRINDING OR FILL WELDING	IF CRACK PENETRATES EITHER THE ROOT OR THE SECOND BEAD, REPLACE PIPE SEGMENT
	2. PATCHING, SLEEVING OR CANNING	LIMITATIONS FOR PATCHES SAME AS 2.B.2.
	3. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.

TYPE OF DEFECT		
5. LEAKS IN BODY OF FITTING OR IN CLAMPS		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. ALL	1. CANNING	EXISTING FACILITIES ONLY.
	REPLACE FITTING OR CLAMP	NO LIMITATIONS.

STEEL REPAIR SELECTION CHART FOR PIPELINES WITH AN MAOP GREATER THAN 100 PSIG BUT LESS THAN 500 PSIG, AND AN OPERATING STRESS LESS THAN 20 PERCENT OF SMYS AT THE PIPELINE MAOP

TYPE OF DEFECT		
1. MECHANICAL DAMAGE: NOTCHES, SCRATCHES, GOUGES, GROOVES, DENTS, AND HOLES		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. DENT-LESS THAN 5% DISTORTION	1. NO REPAIR REQUIRED	NO NOTCHES, SCRATCHES, GOUGES AND GROOVES IN DENT.
B. DENT-MORE THAN 5% DISTORTION (3/8" FOR 6-5/8" O.D. & SMALLER)	1. SLEEVING OR CANNING	DENT MUST NOT PREVENT PROPER FIT UP. MATERIAL USED TO FABRICATE CANS MUST NOT EXCEED 20% SMYS.
	2. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.
C. NOTCH, SCRATCH, GOUGE, GROOVE-LESS THAN 10% OF PIPE WALL THICKNESS	1. GRINDING	PIPE WALL NOT TO BE REDUCED TO LESS THAN 90% OF NOMINAL PIPE WALL THICKNESS. DENT OR DISTORTION LESS THAN 5% OF O.D.
D. NOTCH, SCRATCH, GOUGE, GROOVE DEPTH-MORE THAN 10% BUT LESS THAN 30% OF PIPE WALL THICKNESS	1. GRINDING AND WELDING	DENT OF DISTORTION LESS THAN 5% OF O.D. (3/8" FOR 6-5/8" O.D. AND SMALLER). REPAIR NOT TO EXCEED 1/4 OF PIPE CIRCUMFERENCE NOR 4 SQUARE INCHES. NOT MORE THAN ONE REPAIR PER 5 PIPE DIAMETERS OF LENGTH.
	2. PATCHING	DENT OR DISTORTION LESS THAN 5% OF O.D. (3/8" FOR 6-5/8" O.D. AND SMALLER). PATCH NOT TO EXCEED 1/2 PIPE CIRCUMFERENCE. LENGTH NOT OVER 10 PIPE DIAMETERS ON PIPE OVER 8-5/8 O.D. A MINIMUM OF 3" CLEARANCE BETWEEN PATCHES. PATCH SHALL HAVE ROUNDED CORNERS, WALL THICKNESS SHALL MEET OR EXCEED CARRIER PIPE, AND OPERATE AT LESS THAN 20% SMYS AT PIPELINE MAOP.
	3. SLEEVING OR CANNING	DENT MUST NOT PREVENT PROPER FIT UP. MATERIAL USED TO FABRICATE CANS MUST NOT EXCEED 20 SMYS.
E. NOTCH, SCRATCH, GOUGE, GROOVE-DEPTH GREATER THAN 30% OF PIPE WALL THICKNESS	1. PATCHING	PATCH NOT TO EXCEED 1/2 PIPE CIRCUMFERENCE. LENGTH NOT OVER 10 PIPE DIAMETERS ON PIPE OVER 8-5/8 O.D. A MINIMUM OF 3" CLEARANCE BETWEEN PATCHES. PATCH SHALL HAVE ROUNDED CORNERS, WALL THICKNESS SHALL MEET OR EXCEED CARRIER PIPE, AND OPERATE AT LESS THAN 20% SMYS AT PIPELINE MAOP.
	2. SLEEVING OR CANNING	DENT MUST NOT PREVENT PROPER FIT UP. MATERIAL USED TO FABRICATE CANS MUST NOT EXCEED 20% SMYS PERCENT.
	3. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.
F. HOLE	1. PATCHING	PATCH NOT TO EXCEED 1/2 PIPE CIRCUMFERENCE. LENGTH NOT OVER 10 PIPE DIAMETERS ON PIPE OVER 8-5/8 O.D. A MINIMUM OF 3" CLEARANCE BETWEEN PATCHES. PATCH SHALL HAVE ROUNDED CORNERS, WALL THICKNESS SHALL MEET OR EXCEED CARRIER PIPE, AND OPERATE AT LESS THAN 20 PERCENT SMYS AT PIPELINE MAOP.
	2. SLEEVING OR CANNING	MATERIAL USED TO FABRICATE SLEEVE OR CAN MUST NOT EXCEED 20% SMYS AT THE PIPELINE MAOP.
	3. LEAK CLAMP	PRESSURE RATING OF CLAMP MUST MEET OR EXCEED THE PIPELINE MAOP.
	4. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.

TYPE OF DEFECT 2. CORROSION DAMAGE, TO INCLUDE BOTH GENERAL CORROSION AND LOCALIZED CORROSION PITTING (AS MEASURED WITH A PIT GAUGE)		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. DEPTH LESS THAN 20% OF PIPE WALL THICKNESS	1. NO REPAIR REQUIRED	CLEAN AND RECOAT BURIED PIPE OR REPAINT ABOVE GRADE PIPE.
B. DEPTH BETWEEN 20% AND 30% OF PIPE WALL THICKNESS	1. GRINDING AND WELDING	REPAIR NOT TO EXCEED ¼ CIRCUMFERENCE OF PIPE NOR 4 SQUARE INCHES. NOT MORE THAN ONE REPAIR PER 5 DIAMETERS OF LENGTH.
	2. PATCHING	SAME AS 1.E.1.
	3. SLEEVING	NO LIMITATIONS.
	4. MUELLER SAVE-A-VALVE NIPPLE (OR EQUIVALENT FITTING)	2" MAXIMUM SIZE NIPPLE.
	5. LEAK CLAMP	
C. DEPTH OVER 30% OF PIPE WALL THICKNESS BUT LESS THAN 80%-NO LEAKAGE	1. PATCHING	SAME AS 1.E.1.
	2. SLEEVING	NO LIMITATIONS.
	3. MUELLER SAVE-A-VALVE NIPPLE (OR EQUIVALENT FITTING)	2" MAXIMUM SIZE NIPPLE.
D. DEPTH 80% OF PIPE WALL THICKNESS OR MORE-INCLUDING LEAKING CORROSION PITS	1. PATCHING	SAME AS 1.E.1.
	2. SLEEVING	NO LIMITATIONS.
	3. MUELLER SAVE-A-VALVE NIPPLE (OR EQUIVALENT FITTING)	2" MAXIMUM SIZE NIPPLE.
	4. REPLACE SEGMENT OF PIPE	ENTIRE SECTION MUST BE REMOVED.
E. EXTENT OF THE CORROSION IS SUCH THAT THE REPAIRS IN A, B, C & D ARE NOT FEASIBLE	1. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED SHOULD BE REMOVED.

TYPE OF DEFECT 3. LEAKS IN WELD OR PIPE WELD SEAM		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. ALL	1. PATCHING	SAME AS 1.E.1. EXISTING FACILITIES ONLY.
	2. SLEEVING OR CANNING	EXISTING FACILITIES ONLY. MATERIAL USED TO FABRICATE CANS MUST NOT EXCEED 20% SMYS.
	3. MUELLER SAVE-A-VALVE NIPPLE (OR EQUIVALENT FITTING)	2" MAXMIUM SIZE NIPPLE, FOR EXISTING FACILITIES ONLY.

TYPE OF DEFECT 4. NON-LEAKING CRACKS OR DEFECTS IN WELD OR PIPE WELD SEAM		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. ANY LONGITUDINAL WELD CRACK GREATER THAN 2" LONG, A BRANCH OR CIRCUMFERENTIAL WELD CRACK THAT IS MORE THAN 8% OF WELD LENGTH, OR A CRACK THAT PENETRATES EITHER THE ROOT OR SECOND BEAD	1. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED. IF NOT FEASIBLE TO TAKE MAIN OUT OF SERVICE, INSTALL SLEEVE.
B. ANY LONGITUDINAL WELD CRACK LESS THAN OR EQUAL TO 2" LONG, A BRANCH OR CIRCUMFERENTIAL WELD CRACK LESS THAN OR EQUAL TO 8% OF WELD LENGTH, OR OTHER DEFECTS	1. GRINDING AND FILL WELDING	IF CRACK PENETRATES EITHER THE ROOT OR SECOND BEAD, REPLACE PIPE SEGMENT.
	2. PATCHING, SLEEVING OR CANNING	LIMITATIONS FOR PATCHES SAME AS 1.E.1. MATERIAL USED TO FABRICATE CANS MUST NOT EXCEED 20% SMYS.
	3. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.

TYPE OF DEFECT		
5. LEAKS IN BODY OF FITTING OR IN CLAMPS		
EXTENT OF DEFECT	PERMISSIBLE METHODS OF REPAIR	LIMITATIONS ON METHODS
A. ALL	1. REPLACE FITTING OR CLAMP	NO LIMITATIONS.
	2. CANNING	EXISTING FACILITIES ONLY. MATERIAL USED TO FABRICATE CANS MUST NOT EXCEED 20% SMYS.

STEEL REPAIR SELECTION CHART FOR DISTRIBUTION PIPELINES WITH AN MAOP OF 500 PSI OR GREATER, REFER TO TRANSMISSION LINES SECTION ABOVE FOR TRANSMISSION REPAIRS

TYPE OF DEFECT		
1. MECHANICAL DAMAGE: NOTCHES, SCRATCHES, GOUGES, ARC BURN, GROOVES, DENTS, AND HOLES		
EXTENT OF DEFECT	PERMISSIBLE METHODS OF REPAIR	LIMITATIONS ON METHODS
A. DENT LESS THAN 2% DISTORTION	1. NO REPAIR REQUIRED	NO NOTCHES, SCRATCHES, GOUGES, AND GROOVES IN DENT. NO WELDS AFFECTED BY DENT.
B. DENT MORE THAN 2% DISTORTION (1/4" FOR O.D. LESS THAN 12.750")	1. SLEEVING	DENT MUST NOT PREVENT PROPER FIT UP. IF DENT AFFECTS A WELD, REPAIR AS IN 1.B.2.
	2. REPLACE SERGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.
C. NOTCH, SCRATCH, GOUGE, GROOVE-DEPTH LESS THAN 10% OF PIPE WALL THICKNESS AND LESS THAN 8% OF PIPE W.T. FOR WELDED PIPE 20" O.D. OR LARGER	1. GRINDING	PIPE WALL NOT TO BE REDUCED TO LESS THAN 90% OF NOMINAL WALL THICKNESS (90% ON WELDED PIPE 20" O.D. OR LARGER) DENT OR DISTORTION LESS THAN 2% OF O.D. (1/4" FOR O.D. LESS THAN 12.750").
D. NOTCH, SCRATCH, GOUGE, GROOVE-DEPTH 10% OR MORE OF PIPE WALL THICKNESS. DESIGN PRESSURE LESS THAN 40% SMYS.	1. SLEEVING OR CLOCK SPRING®	DENT OR DISTORTION MUST NOT PRVENT PROPER FIT UP.
E. NOTCH, SCRATCH, GOUGE, ARC BURN GROOVE-DEPTH 10% OR MORE OF PIPE WALL THICKNESS. DESIGN PRESSURE 40% SMYS OR MORE. (8% OR MORE FOR WELDED PIPE 20" OR LARGER.)	1. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED. IF NOT FEASIBLE TO TAKE MAIN OUT OF SERVICE, REPAIR WITH SLEEVE AS IN 1.B.1. %
F. HOLE	1. SLEEVING	MATERIAL USED TO FABRICATE SLEEVE MUST NOT EXCEED 20% SMYS AT THE PIPELINE MAOP.
	2. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.

TYPE OF DEFECT		
2. CORROSION DAMAGE, TO INCLUDE BOTH GENERAL CORROSION AND LOCALIZED CORROSION PITTING (AS MEASURED WITH A PIT GAUGE)		
EXTENT OF DEFECT	PERMISSIBLE METHODS OF REPAIR	LIMITATIONS ON METHODS
A. DEPTH 10% OR LESS OF PIPE WALL THICKNESS.	1. ENGINEERING TO DETERMINE THE REMAINING STRENGTH OF THE PIPE.	ENGINEERING TO DETERMINE THE APPROPRIATE REPAIR METHOD, IF ANY.
B. DEPTH OVER 10% OR LESS OF PIPE WALL THICKNESS BUT LESS THAN 80%-NO LEAKAGE	1. PATCHING	PIPE OF NOT MORE THAN 40,000 PSI SMYS. LENGTH OR WIDTH OF PATCH NOT TO EXCEED 1/2 PIPE CIRCUMFERENCE. A MINIMUM OF 3" CLEARANCE BETWEEN PATCHES. PATCH SHALL HAVE ROUNDED CORNERS.
	2. SLEEVING	NO LIMITATIONS.
	3. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.
C. DEPTH 80% OF PIPE WALL THICKNESS OR MORE-INCLUDING LEAKING CORROSION PITS	1. PATCHING	SAME AS 2.B.1.
	2. SLEEVING	NO LIMITATIONS.
	3. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.
D. EXTENT OF THE CORROSION IS SUCH THAT THE REPAIRS IN A, B, & C ARE NOT FEASIBLE	1. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED SHOULD BE REMOVED.

TYPE OF DEFECT		
3. LEAKS IN WELD OR PIPE WELD SEAM		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. ALL	1. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED. IF NOT FEASIBLE TO TAKE MAIN OUT OF SERVICE, REPAIR WITH SLEEVE.

TYPE OF DEFECT		
4. NON-LEAKING CRACKS OR DEFECTS IN WELD OR PIPE WELD SEAM		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. ANY LONGITUDINAL WELD CRACK GREATER THAN 2" LONG, A BRANCH OR CIRCUMFERENTIAL WELD CRACK MORE THAN 8% OF WELD LENGTH, OR A CRACK THAT PENETRATES EITHER THE ROOT OR SECOND BEAD	1. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED. IF NOT FEASIBLE TO TAKE MAIN OUT OF SERVICE, INSTALL SLEEVE.
B. ANY LONGITUDINAL WELD CRACK LESS THAN OR EQUAL TO 2", A BRANCH OR CIRCUMFERENTIAL WELD CRACK LESS THAN OR EQUAL TO 8% OF WELD LENGTH, OR OTHER DEFECTS	1. GRINDING OR FILL WELDING	AT LEAST 1/8" WALL THICKNESS REMAINING. REDUCE PRESSURE TO BELOW 20% SYMS PRIOR TO MAKING REPAIR. INSPECT REPAIR. IF DEFECT REMAINS, REPAIR AS IN 4.A.1.
	2. SLEEVING	NO LIMITATIONS.
	3. REPLACE SEGMENT OF PIPE	ENTIRE SECTION AFFECTED MUST BE REMOVED.

TYPE OF DEFECT		
5. LEAKS IN BODY OF FITTING OR IN CLAMPS		
EXTENT OF DEFECT	**PERMISSIBLE METHODS OF REPAIR**	**LIMITATIONS ON METHODS**
A. ALL	1. REPLACE FITTING OR CLAMP	X-RAY TIE-IN WELDS OF REPLACED FITTINGS.

3.32A PERMANENT REPAIR SLEEVES

<u>SCOPE:</u>

To establish uniform procedures for installation of permanent repair sleeves.

<u>REGULATORY REQUIREMENTS:</u>

§192.241, §192.245, §192.309, §192.725

<u>OTHER REFERENCES</u>:

API 1104 OR API 1107

<u>CORRESPONDING STANDARDS:</u>

Spec. 3.22, Joining of Pipe – Steel
Spec. 3.32, Repair of Steel Pipe

General

Employees performing welding operations on permanent repair sleeves shall be properly trained and qualified to weld on permanent sleeves per API 1104 or API 1107:

<u>DETAILED PROCEDURES FOR USE OF "PLIDCO SPLIT-SLEEVE" PERMANENT STEEL REPAIR CLAMP:</u>

General

The Plidco Split-Sleeve may be used for permanent repairs of defects in steel pipelines where a full encirclement sleeve is required or where field conditions preclude other methods of repair. The sleeve consists of 2 semi-circular sections of a specified steel seamless pipe with bolting ears on opposing sides. The sleeve is separated into two pieces by removing the bolts and studs. It is then installed on the pipe, the bolts, and studs re-installed and torqued. A special elastomer seal and retainer system accomplishes the sealing process. The Plidco Split-Sleeve may also be welded into position.

Precautions

The following precautions shall be observed when installing the Plidco Split-Sleeve:

- Make sure that there is sufficient space in the trench to safely install the sleeve, torque the bolts, and perform the welding operation (if necessary).
- If installing the sleeve on a pipeline that has an active leak, take precautions to avoid accidental ignition of gas. Use a self-contained breathing apparatus (SCBA) if entering an oxygen deficient atmosphere.
- Make sure that the sleeve is the proper size and length to fully cover the damaged area.
- Check the working pressure and temperature on the label of the sleeve. Do not exceed the maximum working pressure or temperature (also note minimum working temperature).
- Do not use the sleeve to couple pipe.
- Remove all coatings, rust, and scale from the pipe surface where the circumferential seals of the sleeve will contact the pipe. The seal can tolerate minor surface irregularities up to +- 1/32 of an inch.
- Use caution when transporting, lifting, and installing the sleeve as contact with the sleeves or retaining rings can result in the seals being damaged or pulled from their grooves.

- On models with vent taps, make sure that a nipple and valve are installed prior to installation (leave the valve in the open position until the sleeve is torqued). In some cases, the vent tap may be simply plugged off.

Installation

1. Coat exposed surfaces with a lubricant (Buna-Nitrile seals may be lubricated with either a petroleum, silicone, or glycerin-based lubricant. See manufacturer's instructions if using a sleeve with other than Buna-N).
2. Disassemble the sleeve. Clean and lubricate the stud bolts and nuts. Prove free and easy running prior to installation.
3. Place reference marks on the pipe as necessary to assist with centering the sleeve over the damage area.
4. Assemble the sleeve around the pipe making sure the yellow painted ends are matched, and that the sleeve is centered over the leak or damaged area as much as possible. Consider loosely assembling the sleeve to one side of the leak (or damage), then re-positioning it over the critical area.
5. Torque stud bolts and nuts uniformly to the following:

Nominal Diameter of Stud Bolt (in)	Wrench Opening Across Flats (in)	Torque (ft-lb)
5/8 – 11	1-1/16	56
3/4 - 10	1-1/4	98
7/8 – 9	1-7/16	156
1 – 8	1-5/8	233

   (See manufacturer's instructions for torque specifications for larger sizes)
6. To complete assembly, the stud bolts should be rechecked for the recommended torque. The side bars are gapped approximately 1/8-inch when the sleeve is fully tightened.

Field Welding Instructions

The following instructions shall be followed when permanently welding the Plidco Split-Sleeve on steel pipelines.

- The pipeline should be operating at or near MAOP before performing welding operations.
- Use electrodes which have been properly stored in a dry box and are of equal or greater tensile strength than the pipe. Low hydrogen electrodes (E-XX18) are recommended for the fillet welds due to their high resistance to moisture pick-up and hydrogen cracking. They are also the preferred electrode for seal welding the stud bolts and nuts. SMAW filler metals that include the cellulose coated electrodes (E-XX10) are acceptable provided they are proven by procedure qualification. Do not use cellulose coated electrodes for seal welding the stud bolts and nuts. The GMAW welding process may also be used.
- Carefully control the size and shape of the circumferential fillet welds. The size of the fillet weld should be at least 1.4 times the wall thickness of the pipe.
- The fillet weld face should have a concave face, with streamlined blending into both members of the sleeve. Avoid notches and undercuts.
- Monitor the heat generated by welding or preheating, particularly near the area of the seals. Use temperature crayons or probe thermometers. If the heat generated approaches the temperature limit of the seal material, welding should be halted or sequenced to another part of the fitting so that the affected area has a chance to cool (allow cooling in ambient conditions, do not force cool the area).
- The stud bolts are made of AISI 4140 steel with high carbon equivalence (grade B7). Use low hydrogen electrodes (E-XX18) and a modest (not over 200 degrees F) preheat to reduce the problem of hydrogen cracking or pinholes.

The pre-heat will dry out any moisture, oil dampness, or thread lubricant that may be present in the seal weld area. GMAW welding procedures may also be used.

Welding Sequence

1. Fillet weld the ends of the sleeve to the pipe.
2. Seal weld the side openings.
3. Re-torque the stud bolts and nuts.
4. Seal weld around the bottoms of the nuts to the sidebars.
5. Seal weld the nuts to the stud bolts.

Testing

Test the Plidco sleeve if required. Test pressure can be up to 1-1/2 times the design working pressure.

Storage

Store the sleeves in a protected area, out of sunlight. Wrapping the container or sleeve in plastic will help to also protect it from deterioration due to ozone and other atmospheric contaminants. It is recommended that the elastomeric packing, the stud bolts, and the nuts be coated with a heavy grease to prevent rusting and deterioration.

The elastomer packing has a shelf life of 2 to 20 years depending on the storage precautions used. Use the “thumbnail” test to determine if the elastomer is still usable. Push your thumb into the exposed packing. If it returns to its original shape, it should be okay to use. If the thumbnail imprint remains, it should be replaced.

DETAILED PROCEDURES FOR USE OF “TD WILLIAMSON PERMANENT HEMI-HEAD REPAIR SPHERES”:

General

A 20-inch diameter repair sphere is available for use with 4-inch, 6-inch, 8-inch, and 10-inch pipe sizes. This repair sphere is available marked but not cut to a specific pipe size which requires field scarfing. Paint marks on the sleeves indicate approximate points to scarf (check actual pipe dimensions to determine actual points to cut).

Precautions

The following precautions shall be observed when installing the repair sphere:

- Make sure that there is sufficient space in the trench to safely install the sleeve, torque the bolts, and perform the welding operation (if necessary).
- If installing the sleeve on a pipeline that has an active leak, take precautions to avoid accidental ignition of gas. Use a self-contained breathing apparatus (SCBA) if entering an oxygen deficient atmosphere.
- Make sure that the sleeve is the proper size and length to fully cover the damaged area.
- Check the working pressure and temperature on the label of the sleeve. Do not exceed the maximum working pressure or temperature (also note minimum working temperature).
- Do not use the sleeve to couple pipe.

Installation

1. Check the area on the pipe where fitting is to be installed. Clean pipe thoroughly and check roundness. Pipe more than 1/8-inch out of roundness may require special preparation such as grinding the fitting bore.
2. Remove moisture from the pipe before installing sleeve. Heat from an oxy-fuel torch is the most common method of removal.
3. Clean sleeve edges thoroughly where weld is to be made. Remove any paint, dirt, rust, oil, or other foreign matter.
4. Center and level sleeve. The sleeve should be positioned so that the vent port is on the top.
5. Remove the pipe plug from the top of the sleeve.

Fit-Up and Welding Sequence

Employees performing welding operations on the repair spheres shall be properly trained and qualified to weld on permanent sleeves per API 1104 or API 1107:

1. Reduce the welding gap on the end fillet weld to a uniform minimum (1/8-inch maximum is recommended).
2. Establish a 1/16-inch to 3/16-inch gap between the top and bottom fitting halves for the longitudinal welds.
3. Use electrodes which have been properly stored in a dry box and are of equal or greater tensile strength than the pipe. Low hydrogen electrodes (E-XX18) are recommended for the fillet welds due to their high resistance to moisture pick-up and hydrogen cracking. The GMAW welding process may also be used. Use the proper sequence of welds:
   - Longitudinal weld first
   - One end of circumferential weld
   - Other end of circumferential weld
4. Replace the pipe plug in the vent after completion of welding.

Inspection

Conduct a visual examination for cracks, lack of fusion, or undercutting.

3.33 REPAIR OF PLASTIC (POLYETHYLENE) PIPE

SCOPE:

To establish uniform procedures for determining appropriate repairs based on the extent of damage to plastic distribution pipelines. Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service.

REGULATORY REQUIREMENTS:

§192.311, §192.614, §192.725

CORRESPONDING STANDARDS:

Spec. 2.13, Pipe Design – Plastic
Spec. 3.13, Pipe Installation, Plastic (Polyethylene) Mains
Spec. 3.17, Purging Pipelines
Spec. 3.18, Pressure Testing
Spec. 3.23, Joining of Pipe - Plastic - Heat Fusion
Spec. 3.25, Joining of Pipe - Plastic - Mechanical
Spec. 3.34, Squeeze-Off of PE Pipe and Prevention of Static Electricity
Spec. 3.44, Exposed Pipe Evaluation
Spec. 5.14, Cathodic Protection
Spec. 5.17, Reinstating Gas Pipelines and Facilities

PLASTIC REPAIR REQUIREMENTS:

General

Each operator shall take necessary measures prior to beginning repairs to assure that the public and Company personnel are protected from danger. Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.

Prior to performing repairs to plastic pipe, a thorough check shall be made with a combustible gas indicator (CGI). CGI readings shall be continuously taken while repairs are being made until the area is made safe.

Only those methods of repair as detailed in this standard are approved as permanent repairs to polyethylene mains. When a repair cannot be made in conformance with the conditions of this standard, the section of defective pipe shall be cut out and replaced with a new piece of pipe.

If a segment of plastic pipeline is repaired by cutting out the damaged portion, the replacement pipe must be tested to the pressures required for a new line installation and specific information about the pressure test and pipe material shall be documented on the Pre-Tested Pipe Documentation form (N-2743). Refer to Specification 3.18, Pressure Testing, "Recordkeeping."

When a pipeline is exposed, an Exposed Piping Inspection Report form (Form N-2534) shall be completed. Refer to Specification 3.44, Exposed Pipe Evaluation for more information.

Monitoring of Pressure

Gas personnel performing work on pipelines and facilities that could result in the loss pressure or overpressure to the system shall install accurate pressure gauges upstream and downstream of the work site. The pressure gauges shall be continuously monitored as long as is necessary, so that personnel can respond accordingly if system pressures are greatly affected.

Additionally, there may be times when merely monitoring downstream pressure may not be sufficient to prevent customer outages without further action. It may be necessary during warm days or periods of low gas use to intentionally draw down the pressure of the downstream system and observe it to confirm the existence of a looped system prior to altering the system or leaving the area. Consult Gas Engineering for recommendations prior to altering any system's pressure. It may also be necessary to install a temporary bypass if a system is not looped or if the pipeline work could result in loss of pressure to the system. Refer to Specification 3.12, Pipe Installation – Steel Mains for temporary bypass details and requirements.

Any loss of pressure that may have extinguished pilots or that may have affected the normal operation of the customer's gas equipment shall be treated as an outage and the procedures followed as outlined in the GESH, Section 5, Emergency Shutdown and Restoration of Service.

Pre-Tested Pipe

When making a repair as a result of third-party damage or material failure, and it is not possible or practical to test the section of pipe being replaced, pre-tested pipe shall be used. A Pre-Tested Pipe Documentation form (N-2743) shall be filled out and kept at the local office for all pre-tested pipe.

Once the pipe is installed, a copy of the Pre-Tested Pipe Documentation form must be kept for the life of facility with the project file (not at the warehouse with the uninstalled pipe records). The tested pipe shall be segregated from the rest of the pipe stock and identified as pre-tested pipe. The pipe should be periodically inspected and remarked as necessary to indicate its status. Refer to Specification 3.13, Pipe Installation - Plastic (Polyethylene) Mains for PE print line information and for storage and handling of the pipe. Refer to Specification 3.18, Pressure Testing regarding pre-installation testing.

Static Charges

Polyethylene is a poor conductor of electricity, therefore precautions must be taken to prevent build-up of static electrical charges on plastic pipe that is damaged and leaking or at squeeze points. These static charges, if not properly grounded, might cause ignition in a gaseous atmosphere. Refer to Specification 3.34, Squeeze-Off of PE Pipe and Prevention of Static Electricity, "Prevention of Accidental Ignition by Static Electricity," and Specification 3.17, Purging Pipelines, "Prevention of Accidental Ignition" for further items to consider when working near gas pipeline facilities.

Temporary Repairs

Temporary repairs may be made using an approved full encirclement stainless steel clamp; however, these clamps are not acceptable as a permanent repair solution.

Permanent Repairs

Permanent repairs may be made by replacing the damaged pipe with a workable length of new pipe or an approved repair fitting. A repair fitting shall be installed per the manufacturer's instructions.

The following “Plastic Repair Selection Chart” details the required repairs for damaged polyethylene pipe.

PLASTIC REPAIR SELECTION CHART

TYPE OF DEFECT	EXTENT OF DEFECT (As measured by a pit gauge)	PERMISSIBLE METHOD OF PERMANENT REPAIR
Scratches, gouges, cuts, and abrasions	Depth (inches) Pipe Size — Pipe Wall 1/2" CTS — 0.009" 3/4" IPS — 0.009" 1" IPS — 0.012" 1-1/4" IPS — 0.016" 1-1/2" IPS — 0.017" 2" IPS — 0.021" 3" IPS — 0.030" 4" IPS — 0.039" 6" IPS — 0.058"	If defect is less than this depth (i.e., 10 percent of the pipe wall), pipe damage should be sanded smooth. Soap test to assure that no crack or slice exists. Refer to Spec. 3.25, Joining of Pipe - Plastic – Mechanical, for complete instructions for sanding pipe. If defect is equal or greater than this depth, defective pipe shall be replaced with new pipe or repaired with an approved repair fitting.
Kinks, wrinkles, creases, holes, and punctures	No limit	Defective pipe shall be replaced with new pipe or an approved repair fitting.
Cracks	No limit	Defective pipe shall be replaced with new pipe. The new pipe segment should extend at least 3 pipe diameters or 12 inches, whichever is greater, from each end of the crack.

Damage to Service Line

Repair requirements for a dig-in or otherwise damaged plastic service lines.

Direct buried plastic service:

Visually inspect the plastic pipe upstream and downstream from the area of contact. When a service line has been disconnected for repair (merely changing out the meter valve does not apply) resulting in an interruption of gas supply to the customer, the service line must be re-tested from the point of disconnect to the meter valve in the same manner as a new service line before reconnecting. If provisions are made to maintain continuous service to the customer such as by installation of a bypass or maintaining line pack in some fashion, any part of the original service line used to maintain continuous service need not be tested. Refer to Specification 3.18, Pressure Testing. After third party excavation damage to services, a gas leak survey must be performed from the point of damage back to the service tie-in.

Plastic service inserted into an existing casing:

If casing is damaged (broken, bent, or crushed), replace the plastic carrier pipe 2-feet upstream and downstream of the dig-in location and soap-test the replaced section. The casing pipe should be cut back 1-foot from the plastic pipe tie-in points and casing plugs should be installed where the plastic exits and enters the casing. Follow the same procedures as above. If additional damage is found, replace the service.

Heat Damage

Repair requirements for plastic service inserted risers or prefabricated non-corrodible risers for meter sets exposed to, or damaged by, a fire or excessive heat:

- Plastic pipe is sensitive to heat. Therefore, whenever a plastic service inserted riser or prefabricated non-corrodible riser may have been subjected to unusually high temperatures, such as being exposed to a house fire or meter fire, the plastic insert, or the entire riser must be replaced.
- Pressure testing of the service is not sufficient because the plastic piping inside the riser may hold a short duration air pressure test but could still be damaged to the point that, on a long-term basis, it will eventually rupture.

Marking Joints

For plastic joints, the qualified individual who performed the joint shall use a permanent marker to legibly sign the pipe with their first initial and full last name and shall also mark the date of the joint.

Recordkeeping

Records and maps of repairs performed shall be retained for the life of the facilities.

3.34 SQUEEZE-OFF OF PE PIPE AND PREVENTION OF STATIC ELECTRICITY

SCOPE:

To establish a procedure by which polyethylene pipe may be squeezed-off in order to control gas distribution pressure in emergency situations or during certain pipeline construction procedures. Also included in this section are procedures for prevention of accidental ignition by static electricity when working with polyethylene (PE) pipe.

REGULATORY REQUIREMENTS:

§192.751
WAC 296-809, 480-93-178

CORRESPONDING STANDARDS:

Spec. 2.13, Pipe Design - Plastic
Spec. 3.13, Pipe Installation - Plastic Mains
Spec. 3.17, Purging Pipelines
Spec. 3.33, Repair of Plastic Pipe
Avista's Incident Prevention Manual (Safety Handbook)

General

The primary method for pressure control in Avista's distribution systems is the use of available system valves. When polyethylene pipe is encountered, squeeze-off using suitable tools and equipment may also be used as a control method. Squeeze-off is frequently used to stop the flow of gas for emergency repairs; it can also be used to control pressure during the construction of plastic pipelines.

Squeeze-Off Tools

Squeeze-off tools suitable for use on plastic pipe consist of round steel bars and a mechanical or hydraulic means of forcing the bars together. The tools are designed to squeeze the pipe until the inside surfaces meet and shutoff is achieved. To ensure proper flow control and to minimize damage to plastic pipe, squeeze-off tools shall have mechanical stops to limit the minimum gap between the squeeze bars to a tolerance that will prevent damage to the pipe. The bars themselves shall be rounded and shall conform to the diameter recommended by the pipe manufacturer.

Monitoring of Pressures

Gas personnel performing work on pipelines and facilities that could result in the loss of pressure or overpressure to the system shall install accurate pressure gauges upstream and downstream of the work site. The pressure gauges shall be continuously monitored as long as is necessary, so that personnel can respond accordingly if system pressures are greatly affected.

Additionally, there may be times when merely monitoring downstream pressure may not be sufficient to prevent customer outages without further action. It may be necessary during warm days or periods of low gas use to intentionally draw down the pressure of the downstream system and observe it to confirm the existence of a looped system prior to altering the system or leaving the area. Consult Gas Engineering for recommendations prior to altering any system's pressure.

It may also be necessary to install a temporary bypass if a system is not looped or if the pipeline work could result in loss of pressure to the system. Refer to Specification 3.12, Pipe Installation – Steel Mains for temporary bypass details and requirements.

Any loss of pressure that may have extinguished pilots or that may have affected the normal operation of the customer's gas equipment shall be treated as an outage and the procedures followed as outlined in the GESH, Section 5, Emergency Shutdown and Restoration of Service.

Prevention of Accidental Ignition by Static Electricity

Static electricity can build up on any non-conductor such as plastic pipe, therefore the possibility exists that a spark discharge of sufficient energy could cause ignition of natural gas if the proper air/gas mixture is present. It is also possible for repair crews to receive shocks from static electricity even if ignition does not occur.

Potential for ignition is present if all three of the following conditions are present:

1. There is sufficient gas flow to cause extensive turbulence in the pipe;
2. Rust, dust, or other foreign particles are present in the gas streams; and
3. A static charge is present at a point where a combustible air/gas mixture is present.

Emergency flow control situations requiring squeeze-off of polyethylene pipe may involve working in the vicinity of blowing gas. Squeezing, purging, and repair work should only be performed by a trained and qualified individual. The following procedures shall be considered or complied with as appropriate whenever working with blowing gas and plastic pipe:

- If a repair is involved, consider excavating squeeze-off holes at approximately 50-feet from the damaged area, if possible. This will help to limit direct exposure of the employee to blowing gas and debris from the excavation. This will also act as a safety precaution to help mitigate the potential for build-up of static charge due to squeeze-off at the location where gas is releasing to atmosphere.

- If working in the vicinity of leaking gas, CGI readings shall continuously be taken while repairs are being made until the area is made safe.

- A fire suit of appropriate flame-resistant material shall be worn when controlling blowing gas or in a confined hazardous atmosphere. Refer to Avista's Incident Prevention Manual (Safety Handbook).

- If gas is blowing, place the proper fire extinguisher near the job site per Avista's Incident Prevention Manual (Safety Handbook).

- During an emergency situation, a properly trained and qualified gas employee shall assess the need for a Self-Contained Breathing Apparatus (SCBA). If it is determined that an SCBA is required, refer to Avista's Incident Prevention Manual (Safety Handbook) for specific requirements.

- Refer to Specification 3.17, Purging Pipelines, "Prevention of Accidental Ignition" for additional considerations when working in a potentially explosive environment.

PREVENTION OF STATIC ELECTRICITY PROCEDURES

In addition to properly grounding the squeezing tool, one of the two following procedures shall be used to prevent the build-up of static electricity on pipe and tools during squeeze-off. These procedures are not intended to replace the need to properly ground the squeezing equipment.

For either of the following procedures be sure to properly ground the squeezing tool before making contact with the pipe. This will protect the operator in the event of a static discharge by providing a safe path to ground. The ground strap must be attached to a conductive element on the squeeze tool (i.e., metal) to function as intended. Improper connection of the ground strap will provide inadequate protection from a static discharge.

Aerosol Static Suppression Procedure

Only company approved aerosol static suppressor can be sprayed on tools, into cuts, outside or inside pipe or any surface area where needed to suppress static. **Only the surfaces that have been wet by the aerosol static suppressor will dissipate static electricity.** (The aerosol suppressor sprayed on the OUTSIDE of a pipe will not suppress static charges on the INSIDE of the pipe).

Surfaces sprayed with aerosol static suppressor do not need to be kept wet to suppress static. Note that these procedures are not intended to replace the need to properly ground the squeezing tool.

Operating Temperatures – Aerosol static suppressor is effective from any temperature up to 120 degrees F. If the product freezes while in use on a pipe, static will still be suppressed. Freezing will not diminish its static suppression abilities. Aerosol static suppressor will freeze at temperatures below 30 degrees F. However, if the aerosol freezes, simply thaw, shake, and spray. Freezing will not damage the product.

Employees are required to use static suppressant anytime a plastic pipeline is damaged, repaired, taken out of service, or put into service.

1. Pipe Surfaces – Hold the aerosol about 1-foot away from surface and direct spray onto the surface which you wish to suppress static. Spray the entire pipe surface exposed in excavation or bell hole. Spray only enough so the surface appears wet. The aerosol can be held upside down to reach under the pipe. However, periodically upright can to refill internal dip tube and continue spraying. Visually verify the surface of the plastic pipeline being worked on is coated with static suppressor.

2. Cutting Pipe – Spraying into the cut while cutting the pipe will disperse the aerosol static suppressor inside the pipe and suppress static on any surface it contacts inside the cut. The cutting tool shall be sprayed while in the process of cutting.

3. Open Ended Pipe and Purged Pipelines – Apply the static suppressor spray inside and outside the open end of the pipe for added protection when working with open ended or purged pipe. When working around open pipe ends, where there is a hazard of a combustible atmosphere present, spray inside and outside the pipe taking care to wet the cut ends of the pipe also (convergence zone). Hold the aerosol 1 foot away and spray into the inside open end of the pipe and onto exposed pipe edges to eliminate static. Only after spraying the outside of the pipe and the exposed pipe edges should you approach the pipe and spray into the pipe as far as possible in order to eliminate static inside the pipe.

4. Surfaces to be Fused – Prior to fusing, any surface sprayed with aerosol static suppressor should be either wiped off with either isopropyl alcohol or washed off with water before facing or scraping to remove any residue of the spray. Proceed as you would after thoroughly drying, taking care not to leave any water that would affect the fusion.

5. Mechanical Couplings – The aerosol static suppressor will not affect mechanical couplings if the surface is cleaned off with alcohol wipes or washed off with water to remove any residue of the spray.

Wet Soapy Rag Procedure

Proper use of wet soapy rags to treat pipe and tools prior to squeeze-off will reduce the risk of a static discharge and possible ignition. Note: These procedures are not intended to replace the need to properly ground the squeezing tool.

1. Before employees enter an excavation or attempt to control blowing gas, spray the pipe and surrounding area where working with a soap and water solution. Soapy water creates a better conductor than plain water as it will coat the pipe and not bead up.

2. Wrap wet rags around entire length of exposed pipe, leaving enough room to squeeze and cut the pipe. The wet rag should be one continuous length with a “jumper” buried in the soil under the squeeze area. The “jumper” will provide continuity when the pipe is cut, helping to eliminate the possibility of an arc occurring.

3. Keep the pipe and excavation wet until the squeezers are removed. This provides a continuous discharge of static electricity on the pipe.

4. Once the pipe has been squeezed following the procedure outlined below, the pipe is ready to be cut. During the cutting process spray soapy water solution on the area being cut. This will help dissipate the static from the interior of the pipe by giving it a path to follow away from the edge of the cut.

If squeezing the pipe to make a repair, complete the repair at this time. Be aware of the possibility of combustible air/gas mixtures and static charges even after blowing gas is controlled.

If performing squeeze procedure from aboveground out of the bell hole or excavation, follow steps #1 and #4 of the procedures outlined above.

SQUEEZING PROCEDURE

Precautions should be taken to avoid damage to the pipe. Any damage sustained could lead to eventual failure. The location of the squeeze point, the squeezing procedure, and squeeze release procedure below follow the guidelines defined in ASTM F1041, Standard Guide for Squeeze-off of Polyolefin Gas Pressure Pipe and Tubing.

1. Make sure squeezing tool is properly grounded. Ensure the pipe is centered and squared in the squeeze tool. It is important that the pipe be free to spread as it flattens. Failure to do so may result in damage to the pipe or the tool. Also check to see that the tracer wire is not caught between the squeeze bars and the pipe. Make sure that gap stops are set in proper position for the size of pipe.

2. Location of the squeeze point:
   - The squeeze point shall be at least 3 pipe diameters or 12 inches, whichever is greater (as measured from the center of the squeeze point), away from the nearest edge of a fitting or heat fusion joint or sidewall connection, saddle, or mechanical fitting, a prior squeeze-off, or a second squeeze-off tool. Failure to do so may result in damage to the fittings or joint. Clearances from previous squeeze points shall be visually confirmed (i.e., exposed). Consideration should be made during construction to anticipate these situations, especially on service stubs. This will allow adequate spacing to ensure the minimum separation can be met on either side of the squeeze.
   - On a transition fitting, the plastic pipe inside the steel sleeve does not count toward the distance measured for squeezing, therefore start the measurement from where the plastic pipe exits the steel sleeve.

WAC 480-93-178: Item 9 of the WAC requires that plastic pipe not be squeezed within 12 inches or 3 pipe diameters, whichever is greater, from any joint or fitting.

   - Do not squeeze on pipe sections containing deep scratches (greater than 10 percent of the pipe wall thickness).
   - Plastic pipe should only be squeezed-off in the same place one time. It is possible for scale or other metal particles contained in the gas flow to become trapped at the squeeze point. A second squeeze in the same area could force these particles into or through the pipe wall.
3. Squeeze Procedure:
   - The squeeze rate cannot be any faster than 2 inches per minute. Squeeze rate example for a 4-inch IPS pipe: The outside diameter is 4.5 inches, therefore the minimum time to squeeze the pipe is 4.5 inches / 2 inches per minute = 2.25 minutes (2 min 15 sec). The minimum time to squeeze pipe for various pipe sizes are tabulated in the table below. Note that the minimum time to squeeze is longer when the temperature is at or below 32°F. See the corresponding table below. Do not over squeeze the pipe. The squeeze tool should have mechanical stops that come into contact when the pipe is at its maximum squeeze point.
   - If the squeeze rate cannot be adhered to due to an emergency situation, the pipe is considered damaged in the squeezed area and shall be cut out and replaced.
   - Do not use extension levers or cheater bars when using the squeeze tool. Damaged tools should be repaired or replaced.
   - A bubble tight flow control will not always be attainable. If more complete pressure control is needed, a valve should be used, or additional squeeze tools used in series.
4. Squeeze Release Procedure:
   - It is critical to release the squeeze very slowly. The release rate cannot be any faster than 0.5 inches per minute. Squeeze release rate example for a 4-inch IPS pipe: The outside diameter is 4.5 inches, therefore the minimum time to release the squeeze is 4.5 inches / 0.5 inches per minute = 9 minutes. The minimum time to release a squeeze for various pipe sizes are tabulated in the table below. Note that the minimum time to release is longer when the temperature is at or below 32°F. See the corresponding table below.

PE Pipe Squeeze and Release Rates (Air Temperature Over 32° F)					
Pipe Size	**SDR**	**Pipe Avg. O.D. (in.)**	**Minimum Pipe Wall Thickness (in.)**	**Minimum Time to Squeeze Pipe (min:sec)**	**Minimum Time to Release Squeeze (min:sec)**
1/2" CTS	7	0.625	0.090	00:19	01:15
3/4" IPS	11	1.050	0.095	00:32	02:06
1" IPS	11	1.315	0.120	00:40	02:38
1-1/4" IPS	10	1.660	0.166	00:50	03:20
1-1/2" IPS	11	1.900	0.173	00:57	03:48
2" IPS	11	2.375	0.216	01:12	04:45
3" IPS	11.5	3.500	0.304	01:45	07:00
4" IPS	11.5	4.500	0.391	02:15	09:00
6" IPS	11.5	6.625	0.576	03:19	13:15

*SDR - Standard dimension ratio is calculated by dividing the average O.D. of the pipe by the minimum wall thickness in inches.

PE Pipe Squeeze and Release Rates (Air Temperature at or Below 32° F)					
Pipe Size	**SDR**	**Pipe Avg. O.D. (in.)**	**Minimum Pipe Wall Thickness (in.)**	**Minimum Time to Squeeze Pipe (min:sec)**	**Minimum Time to Release Squeeze (min:sec)**
1/2" CTS	7	0.625	0.090	00:38	02:30
3/4" IPS	11	1.050	0.095	01:04	04:12
1" IPS	11	1.315	0.120	01:20	05:16
1-1/4" IPS	10	1.660	0.166	01:40	06:40
1-1/2" IPS	11	1.900	0.173	01:54	07:36
2" IPS	11	2.375	0.216	02:24	09:30
3" IPS	11.5	3.500	0.304	03:30	14:00
4" IPS	11.5	4.500	0.391	04:30	18:00
6" IPS	11.5	6.625	0.576	06:38	26:30

For use of hydraulic squeezers follow the manufacturer's instructions and follow the squeeze and release rates outlined above.

POST-SQUEEZE PROCEDURE

After the squeeze procedure, ensure the following steps are completed to finish the evolution.

1. Visually inspect the affected area for damage.
2. Test for leaks using a soap and water solution.
3. Wrap black electrical tape around the pipe on both sides of the squeeze point and over the squeeze point in the shape of an "X" prior to backfilling.

3.35 DETAILED PROCEDURES FOR USE OF “ADAMS” STYLE REPAIR CLAMPS

SCOPE:

To establish uniform procedures for the installation and use of Adams style repair clamps.

REGULATORY REQUIREMENTS:

§192.627, §192.711

CORRESPONDING STANDARDS:

Spec. 3.32, Repair of Steel Pipe
GESH Section 2 – Leak and Odor Investigation

General

“Adams” style repair clamps are cylindrical sections of stainless steel that have an internal, attached lining of rubber or other pliable material. Some models of these clamps are designed so that they may be opened along their longitudinal axis and slipped onto a section of pipeline. Other models come in two separate sections that have interlocking gaskets and bolts on both sides. Once in place, the bolts are tightened resulting in a decrease in the annular area between the pipe and the clamp. The snug fit between the rubber gasket and the pipe will usually eliminate any leakage.

These clamps are used on a temporary basis to repair leaks or mechanical damage to steel or polyethylene pipe caused by outside forces or to reinforce small areas of corrosion damage on steel or polyethylene pipe. Temporary leak clamps should not be used on pipelines that are badly corroded or that are weakened due to serious damage. Refer to Specification 3.32, Repair of Damaged Pipelines, “Steel Repair Selection Charts,” to determine when a leak clamp may be used.

The intent of this temporary repair is to make the site safe per GESH Section 2 – Leak and Odor Investigation. Thereafter, the permanent repair can be completed as soon as possible. These clamps should not be backfilled. It is permissible to cover the trench with steel road plates, if necessary.

“Adams” style clamps shall not be tapped and may not be welded to the pipeline. Only clamps approved by Gas Engineering may be used for temporary repairs. Employees using temporary repair clamps shall be properly trained and qualified to install each style of clamp available on service/crew vehicles.

Precautions

The following precautions are applicable when installing all brands and styles of leak repair clamps:

1. Ensure there is sufficient space in the trench to apply the clamp and torque the bolts. Use manual wrenches to initially tighten the clamp if there is danger of accidental ignition of a gaseous atmosphere.

2. If installing the clamp on a pipeline that has an active leak, take precautions to prevent accidental ignition of the gas. Use a self-contained breathing apparatus (SCBA) as outlined in Avista’s Incident Prevention Manual (Safety Handbook) if entering an oxygen deficient atmosphere.

3. Verify clamp size by checking the diameter of the pipe and the length of the damaged area.

4. Clean the pipe to remove loose dirt and corrosion from the surface. Loose coating material should be removed until a reasonably smooth surface remains.
5. Place marks on the pipe to reference the leak. Use these marks to assure that the clamp is properly positioned. Use a paint stick, grease pencil, or other visible marker.
6. Applicable 360-degree leak clamps with outlets should have a nipple and valve installed prior to installation. Install the outlet pointing outward where it will be accessible when the clamp is tightened. The valve should be left in the open position until the clamp is fully tightened.
7. When using clamps that have a gasket that provides partial coverage ensure the gasket is centered over the damage area before the clamp is tightened.
8. Ensure no foreign materials stick to the gasket as it is brought around the pipe. Check that no materials become lodged between the gasket and the pipe as the nuts are tightened.
9. Use the proper wrench for the job. Use a torque wrench if specified by the manufacturer to achieve proper bolt torque.
10. Keep bolt threads free of dirt and foreign materials.
11. Test for leaks after clamp is tightened.

Romac Style SS1 Procedures

The following procedures are applicable to 3/4-inch to 3-inch Style SS1 Stainless Steel Repair Clamps manufactured by Romac Industries, Inc.

1. Visually inspect the clamp for damage and to ensure that no parts are missing. Clean the pipe surface that will be covered by the clamp. Ensure the area around the damaged area is large enough to accommodate the installation of the clamp and the torque wrench handle.
2. Place reference marks on the pipe in line with the crack or hole in the pipe, if practical. Center the clamp over the repair area before installing it and place additional marks on the pipe at the edges of the clamp. These marks will assist centering the gasket material over the damaged area.
3. Back off the nuts to the end of the bolts, but do not remove them. Separate the clamp and wrap it around the pipe at a location remote to the damage area.
4. Slide the lifter bars up the receiver lug profile and snap into place over the side-bar edge. Ensure the gasket tails are not folded under, they must be lying flat around the pipe.
5. Using the reference marks, slide the clamp over the damaged area. Ensure the bolts are in a position where they can be tightened properly.
6. Tighten all nuts evenly in 20 ft-lb. increments. Start in the center and work toward each end keeping torques as evenly balance as possible. Using a torque wrench, tighten all nuts to the following values:

Nominal Pipe Diameter (in)	Torque (ft–lb)
4 and below	30-35
6 and above	75-85

7. Wait 10 minutes and then retighten to ensure the proper torque is maintained.

Adams and Mueller Style Procedure

The following procedures are applicable to repair clamps manufactured by Mueller:

1. Make sure the clamp style matches the diameter of the pipeline and the length of the repair.

2. Clean the pipe thoroughly, removing any burrs and loose material.

3. Slip the bolt head(s) out of the lug(s) and separate the clamp. On 2-piece clamps, loosen and remove all of the bolts, nuts, and washers to separate the clamp.

4. Mark the damaged area, if practical, for alignment purposes. Ensure the gasket will cover the damaged area by at least 1 inch when aligned. Use a longer clamp if necessary.

5. Place the clamp on the pipeline to the side of the damaged area.

6. While compressing the clamp, slip the bolt head(s) back into the lug(s). On a Full-Seal 2-piece clamps, align the bolt holes in the side lugs and re-install the bolts, nuts, and washers. Finger-tighten only until in final position.

7. On Full-Seal clamps, ensure the inter-locking gasket fingers are in the proper position. Gap bridges should slide under the bank (rotate the clamp slightly as necessary to prevent any hang-up or binding).

8. Slide the clamp carefully over the damage area and note alignment marks.

9. Tighten bolts alternately to the torque value specified below:

Adams/Mueller Series		Torque (lbs. in)
200	Servi-Seal (all)	500
500	5/8"	840
500	1/2"	480
520	2"-3 1/2" Diameter	420
520	4"-8" Diameter	600
520	10"-12" Diameter	780

Notes:

- Do not reuse temporary clamps unless it is determined that there is no significant damage to the gasket material and that the bolts have not been damaged. If there is any doubt, discard the leak clamp.

- “Adams” style repair clamps may be used on polyethylene pipe provided that the clamp is properly sized for the pipeline O.D., it can be installed safely, and the proper precautions are taken to prevent accidental ignition by static electricity.

- Refer to the manufacturer’s instructions for installing clamps not listed in this procedure.

3.4 MISCELLANEOUS CONSTRUCTION

3.42 CASING AND CONDUIT INSTALLATION

SCOPE:

To establish a uniform procedure for casing design to be used under roadways, railroad crossings, and alongside or within bridge structures.

REGULATORY REQUIREMENTS:

§192.323

WAC 480-93-110, 480-93-115

CORRESPONDING STANDARDS:

Spec. 2.15, Bridge Design
Spec. 2.32, Cathodic Protection
Spec. 3.33, Repair of Plastic (Polyethylene) Pipe

DESIGN REQUIREMENTS:

General

In general, casings are used only where required by permit, ordinance, or governing agency for railroad, highway, and bridge crossings. The principal purpose for a casing is to provide a means of installation and replacement of a main without interrupting traffic on the traveled way. It is also to provide a conduit for gas to escape from under the traveled way should a leak occur in the carrier pipe.

Casings shall be designed with sufficient strength to withstand anticipated stresses due to bending, torsion, and temperature change. Gas Engineering should be consulted when installing a casing.

Gas Engineering has concluded that none of the Company's casing end seals are "…strong enough to retain the MAOP pressure of the pipe…" and consequently, there is not a need to either add vent pipes or run a strength calculation on unvented, post-1970 casing to prove compliance with §192.323.

> **WAC 480-93-115:** Whenever a gas pipeline company installs a main or transmission line in a casing or conduit of any type material, the gas pipeline company must seal the casing ends to prevent or slow the migration of gas in the event of a leak.
>
> Service lines installed in a casing or conduit must be sealed at the end nearest the building to prevent or slow the migration of gas towards the building in the event of a leak.

Link type seals and rubber boots are acceptable ways to seal the ends of casings. Conduits may be sealed with spray foam or other suitable sealant. The requirements for end sealing services as outlined in WAC 480-93-115 are applicable to Washington State only and is a best practice in Idaho and Oregon.

Casing Size

The casing shall have a minimum inside diameter sufficiently larger than the outside diameter of the carrier pipe to accommodate placement and removal of the carrier pipe. Consideration should be given to any possible future need to increase the carrier pipe size and the casing should be sized accordingly.

The following tables may be used as guidelines for sizing casing:

STEEL CASING PIPE SPECIFICATIONS FOR STEEL CARRIER PIPE			
Nom. Dia. of Steel Carrier Pipe (in)	**Nom. Dia. of Casing Pipe (in)**	**Minimum Wall Thickness (in)**	**Minimum Nom. Dia. of Vent Pipe (in)**
3/4	2	0.125	2
1 1/4	3	0.125	2
2	6	0.250	2
3	6	0.250	2
4	8	0.250	2
6	10	0.250	2
8	12	0.250	2
10	16	0.250	2
12	20	0.250	2
16	24	0.281	3
20	26	0.375	3

CASING PIPE SPECIFICATIONS FOR PLASTIC (POLYETHYLENE) CARRIER PIPE	
Nom. Dia. of Plastic Carrier Pipe (in)	**Suggested Casing Size* (in)**
1/2	2
3/4	2
1 1/4	3
2	4
3	6
4	8
6	10

*NOTES:
(1) Suggested sizes are given to prevent damage to plastic carrier pipe should water leak into casing and freeze.
(2) Casing specifications for steel casings apply as shown in the previous table.
(3) PVC plastic casing must be Schedule 40 for size 2-inch through 6-inch and Schedule 80 for sizes 8-inch and above.

Casing Specifications

Plastic conduit <u>shall not</u> be used for steel carrier pipeline as it interferes with the ability to cathodically protect the steel carrier pipeline.

Buried steel casings with steel carrier pipe shall be bare to prevent potential shielding of cathodic protection.

Casing pipe should be butt welded with full circumferential welds to similar quality as the carrier pipeline. Some governing agencies may require the use of a galvanized casing on bridges or other structures. If a galvanized casing is required, the casing should be ordered with a galvanizing cutback on each end (typically 3 to 4 inches in length) to accommodate welding. When a cutback is used, the weld and the bare pipe surrounding the weld shall be painted with a galvanizing paint or other approved coating after welding is complete. If a cutback is not used, weld fume extraction equipment and welder respiratory protection equipment should be used. The weld shall be painted with a galvanizing paint or other approved coating after welding is complete.

Casings shall be seamless, ERW or DSAW welds, but need not meet specifications for carrier pipe. “Casing grade quality pipe” is preferred as it is lower in cost.

Casings designed for railroad crossings shall be per Drawing E-33947, Sheet 1 of 2. Casings designed for state or interstate highway crossings shall be per Drawing E-33947, Sheet 2 of 2. Drawings are located at the end of this specification.

Keep moisture from filling the casing. Normally, use of an approved end seal will keep the carrier pipeline dry and the ends free of debris. Although crossings should not be located where a freeway or expressway is in a depressed location, when this is unavoidable, additional measures may be taken to keep carrier pipeline dry. Contact Gas Engineering for advice in using additional sealing methods when encountering potential high water table areas.

INSTALLATION REQUIREMENTS:

Installing Steel Carrier Pipe in Casing

The inside wall of the casing pipe must be free of sharp or rough surfaces. When necessary, the entire length of the casing pipe shall be cleaned to remove debris. Suggested means of cleaning include purging with air and/or use of pigging devices.

Casings should have a minimum of one vent pipe installed and it is preferred to have a vent pipe at each end. Vent pipes should be welded to the casing prior to inserting carrier pipe to prevent damage to the carrier pipe. If two vents are installed, the casing vent at the lower elevation shall be attached to the bottom of the casing and the other to the top of the casing. This provides for natural circulation through the vents. It also allows for the ability to blow accumulated water out of the casing through the lower vent. Vent pipes shall be constructed of carbon steel as delineated in Drawing E-33947 at the end of this specification. Do not use factory-coated steel pipe for the below-grade portion of the vent piping, as it can appear to be gas-carrying pipe when excavated in the future.

The above ground portion of vent pipes shall be coated with paint (tape-wrapping below ground is not required). The vent pipe must not contact the steel carrier pipeline. The vent shall be installed to prevent water or other debris from entering the vent opening.

The carrier pipe shall be inspected for damage prior to its installation and during the insertion operation as the pipe enters and leaves the casing pipe.

Casing Insulators - For steel carrier pipelines, casing insulators should be installed with maximum 5 feet separation. Close spacing prevents grounding of steel carrier pipeline to casing. Install two casing insulators at each end of casing to assure carrier pipe does not come in contact with end of casing.
The carrier pipe shall be inspected at the leading end for damage after the installation by using a flashlight to illuminate the interior of the casing. Any significant gouging of the pipe coating (steel carrier pipeline) must be repaired or replaced.

A cathodic reading should be taken immediately after installation to assure that the carrier pipeline is not electrically shorted to the casing.

Permanent test leads shall be attached to at-least one end of the casing and the steel carrier pipe. Install test leads at both ends of the casing whenever possible. The wire connections on the casing shall be covered with mastic or tape wrap similar to steel pipe. Refer to Drawing E-33947 at the end of this specification.

WAC 480-93-115: The state of Washington requires that a separate test lead shall be attached to the casing and to the steel gas pipeline to verify that no electric short exists between the two.

End Seals – Link type seals with centering blocks shall be used to seal casing ends when steel carrier pipe is installed. The carrier pipe shall be supported to keep the proper concentric alignment when installing these types of seals.

The bottom of the trench adjacent to each end of the casing shall be graded to provide firm, uniform, and continuous support for the carrier pipeline.

Installing PE Carrier Pipe in Casing

The inside wall of the casing pipe must be free of sharp or rough surfaces. When necessary, the entire length of the casing pipe shall be cleaned to remove debris. Suggested means of cleaning include purging with air and/or use of pigging devices.

Vent pipes shall be welded to the casing at each end prior to inserting carrier pipe to prevent damage to the carrier pipe. The casing vent at the lower elevation shall be attached to the bottom of the casing and the other to the top of the casing. This provides for natural circulation through the vents. It also allows for the ability to blow accumulated water out of the casing through the lower vent. Vent pipes shall be constructed of carbon steel as delineated in Drawing E-33947 at the end of this specification.

The aboveground portion of vent pipes shall be coated with paint (tape-wrapping below ground is not required). The vent shall be installed to prevent water or other debris from entering the vent opening.

Casing Insulators - For plastic carrier pipelines, install casing insulators as needed to slip pipe smoothly into casing. Install two casing insulators at each end of casing to assure plastic carrier pipe does not come in contact with end of casing.

The leading end of the carrier pipe shall be closed before insertion and the pipe inspected for damage at the leading end after the installation by using a flashlight to illuminate the interior of the casing. Any significant gouging of the pipe wall (polyethylene carrier pipeline) must be repaired or replaced as described in Specification 3.33, Repair of Plastic (Polyethylene) Pipe.

End Seals – Boot type seals shall be used to seal casing ends when plastic carrier pipe is installed. The carrier pipe shall be supported to keep the proper concentric alignment when installing these types of seals.

For plastic pipe that is encased in steel, maintain continuity of the tracer by insertion of tracer wire along with the plastic through the steel casing. Refer to Drawing B-34947 at the end of this specification.

The bottom of the trench adjacent to each end of the casing shall be graded to provide firm, uniform, and continuous support for the carrier pipeline.

Casing pipe containing plastic main or service shall not be subjected to excessive heat. As a result, bridge casings should be hung either under or within bridge structures to avoid the heating effects of direct sunlight.

Casing pipe containing plastic main or service pipe shall not be squeezed or deformed except in an emergency. If this is necessary, the casing and plastic carrier pipe shall be replaced. Refer to Specification 3.33, Repair of Plastic (Polyethylene) Pipe.

Conduits

The use of conduits should be discouraged. Occasionally it is necessary to install a conduit to enable road construction, etc., prior to installation of a plastic gas main or service.

Plastic conduit may only be used for polyethylene carrier pipeline if it provides sufficient strength to withstand anticipated stresses due to overburden, bending, torsion, and temperature change and is approved by permitting agency.

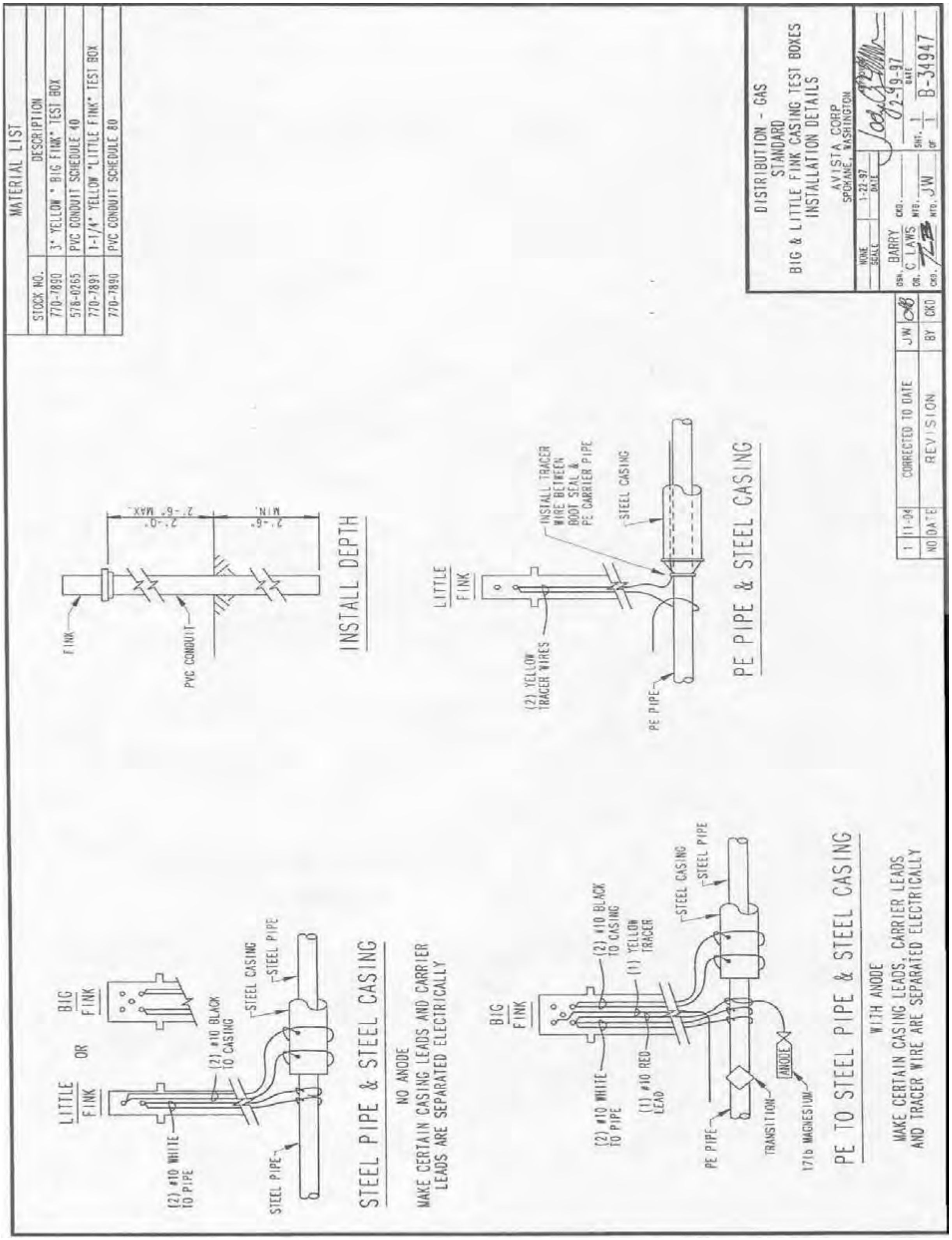
Only gray or yellow plastic conduit should be used. Conduit should be clearly marked or labeled to indicate that a gas pipeline is housed within. One method is to wrap the conduit with yellow tape stamped "Caution--Natural Gas" in "candy cane" fashion. No white plastic conduit shall be used as it may be confused with water irrigation pipe.

Conduit should be sized to allow carrier pipe and tracer wire to pass easily through at the time of insertion.

The bottom of the trench adjacent to each end of the conduit shall be graded to provide firm, uniform, and continuous support for the carrier pipeline. Protection from sharp edges of conduit must be provided for main and service inserts such as, but not limited to, a split piece of plastic pipe between the carrier pipe and the edge of the conduit or use of a casing insulator. As the carrier pipe exits the conduit, ensure that it does not scrape the end of the conduit.

Installed conduits should be properly noted on Company maps.

Inserted steel services may be referred to as a conduit, typically in regard to Avista's mapping procedures within Avista's AFM (GIS) System. This particular situation is the only non-plastic conduit for natural gas use at the Company.



	PIPE SYSTEMS CASING & CONDUIT INSTALLATION	REV. NO. 18 DATE 01/01/20
AVISTA Utilities	**STANDARDS** NATURAL GAS	6 OF 8 SPEC. 3.42

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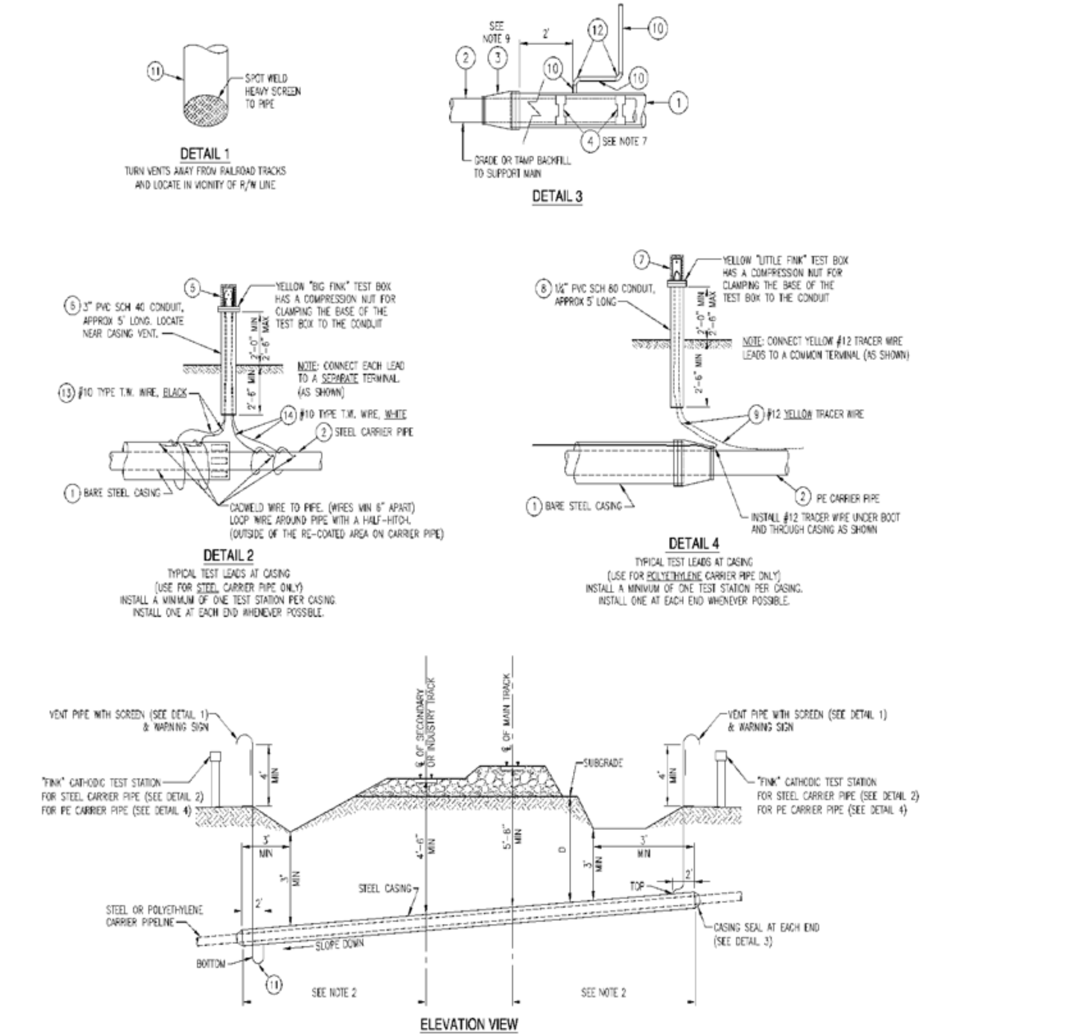


MATERIAL LIST

NO	DESCRIPTION
1	BARE STEEL PIPE (CASING)
2	COATED STEEL PIPE OR POLYETHYLENE PIPE (CARRIER)
3	BOOT TYPE OR LINK TYPE CASING STEEL
4	THINSULATOR
5	CATHODIC TEST STATION ("BIG FINK")
6	PVC, 3", 5' LONG SCH 40
7	CATHODIC TEST STATION ("LITTLE FINK")
8	PVC, 1½", 5' LONG, SCH 80
9	YELLOW TRACER WIRE, #12, SOLID
10	VENT PIPE, 2" STEEL, 180', STD WALL
11	RETURN BEND, 2" STEEL, 180', STD WALL
12	90° ELBOW, 2", STEEL, STD WALL
13	BLACK WIRE, #10, SOLID
14	WHITE WIRE, #10, SOLID

NOTES:

1. THIS DRAWING SATISFIES MINIMUM REQUIREMENTS OF MOST RAILROAD COMPANIES. REQUIREMENTS OF A PARTICULAR RAILROAD PERMIT SHALL SUPERSEDE THE REQUIREMENTS OF THIS DRAWING. CONTACT THE REAL ESTATE DEPARTMENT FOR ASSISTANCE OBTAINING REQUIRED PERMITS.
2. CASING SHALL EXTEND AT LEAST 45 FEET OR 2(D) + 20 FEET, EACH SIDE FROM CENTERLINE OF OUTSIDE TRACK MEASURED AT RIGHT ANGLES TO THE TRACK.
3. PIPELINES SHALL BE LOCATED, WHERE PRACTICAL, TO CROSS TRACKS AT APPROXIMATELY RIGHT ANGLES, BUT PREFERABLY AT NOT LESS THAN 45 DEGREES. PIPELINE SHALL NOT BE LOCATED CLOSER THAN 50 FEET TO ANY PORTION OF A RAILROAD BRIDGE, BUILDING, OR OTHER IMPORTANT STRUCTURE. UNLESS APPROVED BY THE RAILROAD COMPANY.
4. TRENCHING OR JACKING PITS FOR BORING SHALL BE A MINIMUM OF 30 FEET FROM THE CENTERLINE OF THE CLOSEST TRACK.
5. CASING VENT PIPING SHALL BE WELDED TO CASING PRIOR TO INSTALLATION OF CARRIER PIPE. WHENEVER POSSIBLE, INSTALL ONE VENT AT EACH END OF THE CASING. WHEN INSTALLING TWO CASING VENTS, ONE VENT SHALL BE ATTACHED TO BOTTOM OF CASING AND THE OTHER TO THE TOP. CASING SHOULD BE SLOPED AS TO ALLOW NATURAL CIRCULATION THROUGH VENT ATTACHED TO BOTTOM TOWARDS AND OUT OF VENT ATTACHED TO TOP OF CASING.
6. THE CASING SHALL BE VISUALLY INSPECTED AND CLEANED PRIOR TO INSTALLING THE CARRIER PIPE TO REMOVE DEBRIS AND FOREIGN MATERIAL.
7. IF STEEL CARRIER PIPE IS USED, THINSULATORS SHOULD BE SPACED WITH MAXIMUM 5 FEET SEPARATION OVER ENTIRE LENGTH OF CASING. IF PE CARRIER PIPE IS USED, INSTALL THINSULATORS AS NEEDED TO SLIP PIPE SMOOTHLY INTO CASING. INSTALL TWO THINSULATORS AT EACH END OF THE CASING FOR EITHER STEEL OR PE CARRIER PIPES WITH 5 FEET MAXIMUM SEPARATION TO ASSURE PIPE DOES NOT COME IN CONTACT WITH END OF CASING.
8. USE OF POLYETHYLENE CARRIER PIPE MUST BE APPROVED BY PERMIT OF RAILROAD COMPANY. GENERALLY, WHEN USE OF POLYETHYLENE CARRIER PIPE IS PERMITTED, CASING MUST EXTEND COMPLETELY ACROSS RAILROAD RIGHT-OF-WAY.
9. BOOT TYPE CASING SEALS SHALL BE USED TO SEAL CASING END WHEN PLASTIC CARRIER PIPE IS USED. LINK TYPE SEALS WITH CENTERING BLOCKS SHALL BE USED WHEN STEEL CARRIER PIPE IS USED. THE CARRIER PIPE SHALL BE SUPPORTED TO KEEP THE PROPER CONCENTRIC ALIGNMENT WHEN INSTALLING LINK TYPE SEALS. ADDITIONAL SEALING METHODS MAY BE REQUIRED TO KEEP CARRIER PIPE DRY. CONTACT GAS ENGINEERING FOR ADVICE ON SEALING ENDS WHEN ENCOUNTERING POTENTIAL HIGH WATER TABLE AREAS.

SUPERSEDES C-33947 SHT 1, DATED 4-12-93

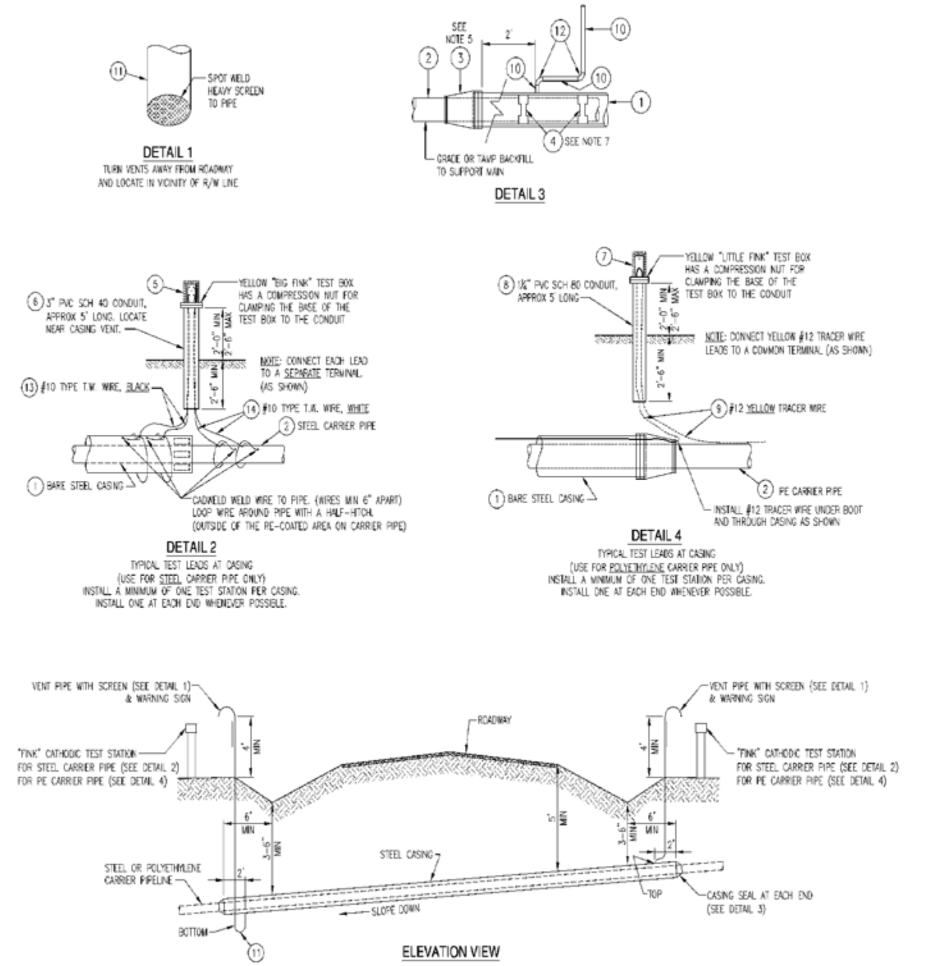
DISTRIBUTION - GAS
STANDARD
STEEL CASING DETAIL
FOR PE OR STEEL PIPELINES
CROSSING UNDER RAILROAD RIGHT OF WAY

AVISTA CORP
SPOKANE, WASHINGTON

NONE	10-9-15	APPROVED
SCALE	DATE	11-6-15
DESIGN HARDING	CHECKED MRS	DATE
DRAWN TJH	NOTED	
CHECKED TJH	NOTED	SHT 1 OF 2 E-33947

NO	DATE	REVISION	BY	CKD	AS BUILT

E-33947



MATERIAL LIST

NO	DESCRIPTION
1	BARE STEEL PIPE (CASING)
2	COATED STEEL PIPE OR POLYETHYLENE PIPE (CARRIER)
3	BOOT TYPE OR LINK TYPE CASING STEEL
4	THINSULATOR
5	CATHODIC TEST STATION ("BIG FINK")
6	PVC, 3", 5' LONG, SCH 40
7	CATHODIC TEST STATION ("LITTLE FINK")
8	PVC, 1¼", 5' LONG, SCH 80
9	YELLOW TRACER WIRE, #12, SOLID
10	VENT PIPE, 2" STEEL, 180°, STD WALL
11	RETURN BEND, 2" STEEL, 180°, STD WALL
12	90° ELBOW, 2", STEEL, STD WALL
13	BLACK WIRE, #10, SOLID
14	WHITE WIRE, #10, SOLID

NOTES:

1. THIS DRAWING SATISFIES MINIMUM REQUIREMENTS OF MOST AGENCIES. REQUIREMENTS OF A PARTICULAR PERMIT SHALL SUPERSEDE THE REQUIREMENTS OF THIS DRAWING. CONTACT THE REAL ESTATE DEPARTMENT FOR ASSISTANCE OBTAINING REQUIRED PERMITS.
2. CASING VENT PIPING SHALL BE WELDED TO CASING PRIOR TO INSTALLATION OF CARRIER PIPE. WHENEVER POSSIBLE, INSTALL ONE VENT AT EACH END OF THE CASING. WHEN INSTALLING TWO CASING VENTS, ONE VENT SHALL BE ATTACHED TO BOTTOM OF CASING AND THE OTHER TO THE TOP. CASING SHOULD BE SLOPED AS TO ALLOW NATURAL CIRCULATION THROUGH VENT ATTACHED TO BOTTOM TOWARDS AND OUT OF VENT ATTACHED TO TOP OF CASING.
3. THE CASING SHALL BE VISUALLY INSPECTED AND CLEANED PRIOR TO INSTALLING THE CARRIER PIPE TO REMOVE DEBRIS AND FOREIGN MATERIAL.
4. IF STEEL CARRIER PIPE IS USED, THINSULATORS SHOULD BE SPACED WITH MAXIMUM 5 FEET SEPARATION OVER ENTIRE LENGTH OF CASING. IF PE CARRIER PIPE IS USED, INSTALL THINSULATORS AS NEEDED TO SLIP PIPE SMOOTHLY INTO CASING. INSTALL TWO THINSULATORS AT EACH END OF THE CASING FOR EITHER STEEL OR PE CARRIER PIPES WITH 5 FEET MAXIMUM SEPARATION TO ASSURE PIPE DOES NOT COME IN CONTACT WITH END OF CASING.
5. BOOT TYPE CASING SEALS SHALL BE USED TO SEAL CASING END WHEN PLASTIC CARRIER PIPE IS USED. LINK TYPE SEALS WITH CENTERING BLOCKS SHALL BE USED WHEN STEEL CARRIER PIPE IS USED. THE CARRIER PIPE SHALL BE SUPPORTED TO KEEP THE PROPER CONCENTRIC ALIGNMENT WHEN INSTALLING LINK TYPE SEALS. ADDITIONAL SEALING METHODS MAY BE REQUIRED TO KEEP CARRIER PIPE DRY. CONTACT GAS ENGINEERING FOR ADVICE ON SEALING ENDS WHEN ENCOUNTERING POTENTIAL HIGH WATER TABLE AREAS.

SUPERSEDES C-33947 SH 1, DATED 4-12-93

DISTRIBUTION - GAS
STANDARD
STEEL CASING DETAIL
FOR PE OR STEEL PIPELINES
CROSSING STATE & INTERSTATE HIGHWAYS
AVISTA CORP
SPOKANE, WASHINGTON

NONE (SCALE)	10-9-15 (DATE)	APPROVED	
DESIGN HARDING	CHECKED DRS	11-6-15 (DATE)	
DRAWN TJH	NOTED		
CHECKED TJH	NOTED	SHT 2 OF 2	E-33947

NO	DATE	REVISION	BY	CK'D	AS BUILT

3.43 LAND DISTURBANCE REQUIREMENTS

SCOPE:

To establish uniform procedures related to gas construction land disturbance activities, identify permit requirements, and establish excavation and sediment control Best Management Practices (BMP's).

REGULATORY REQUIREMENTS:
Federal – 40 CFR 123.25(a), 122.26(a)(1)(v), 122.26(b)(14)(x), and 122.26(b)(15)
Idaho – Idaho Department of Environmental Quality (IDEQ)
Washington – Washington State Department of Ecology (DOE)
Oregon – Oregon Department of Environmental Quality (DEQ)
Local Jurisdiction Critical Areas, Stormwater Erosion and Site Disturbance Regulations

CORRESPONDING STANDARDS:

Spec. 3.15, Trenching and Backfilling

General

Land disturbance and excavation activities require proper planning. Prior to excavation or land disturbance associated with gas construction work, it is necessary to acquire the appropriate locates, permits, easements, and in many cases to implement appropriate stormwater erosion control measures to prevent inappropriate discharge of sediment off of the construction site. Additionally, some construction areas fall within or near environmentally sensitive areas (e.g., floodplains, wetlands, streams, steep slopes) and have prescriptive requirements regarding techniques for disturbed areas, as well as removal and disposal of excavated material.

This specification shall apply to employees, contractors, activities, and land disturbance, directly or indirectly associated with gas construction projects. Compliance with this specification will reduce the potential negative impacts of construction activities and provide protection of stormwater, groundwater, water bodies, watercourses, and wetlands consistent with the Clean Water Act requirements.

Gas related land disturbance and excavation activities shall be completed in accordance with this specification and Specification 3.15, Trenching & Backfilling. Gas construction activity shall be performed in a manner to minimize stormwater discharge from the construction site. Temporary erosion and sediment control measures shall be removed after final site stabilization has occurred.

Necessary action shall be taken to minimize the depositing and tracking of mud, dirt, sand, gravel, rock, or debris onto public or private roads, driveways, parking lots, and the like.

Acquisition and adherence to appropriate permits and implementation of sediment control best management practices (BMP's) are necessary steps related to excavation activities. A list of land disturbance activities, required permits, and excavation requirements is detailed in Table 2.

Definitions

BEST MANAGEMENT PRACTICES (BMPs): Acceptable techniques that can be implemented to protect water quality caused by development or construction activities. A BMP can be a policy, practice, procedure, technology, structure, or device that controls, prevents, or removes discharges not meeting water quality standards.

CESCL: Certified Erosion & Sediment Control Lead. A person that has been certified by the authorized state jurisdiction to conduct construction site inspections to ensure stormwater mitigation measures are being followed as specified in the Stormwater Pollution Prevention Plan.

CONSTRUCTION GENERAL PERMIT: A permit issued by the regulatory entity having jurisdiction in a state that provides guidelines construction operators should follow to comply with the requirements of the federal stormwater regulations.

DOE: Washington State Department of Ecology

EPA: United States Environmental Protection Agency

EROSION: The wearing away of the land surface by water, wind, ice, or gravity.

EROSION AND SEDIMENT CONTROL PLAN (ESC): The ESC is a drawing detailing where and what types of Best Management Practices (BMPs) are to be used to control stormwater pollution during and after construction, as well as methods for final stabilization. This plan is typically required as a part of the permit process and also a subpart of a larger document known as the Stormwater Pollution Prevention Plan (SWPPP).

IDEQ: Idaho Department of Environmental Quality

NOTICE OF INTENT (NOI): A form filed with the appropriate regulatory entity before beginning construction when required to secure a Construction General Permit.

NOTICE OF TERMINATION (NOT): A form filed with the appropriate regulatory entity when construction activities have ended as a requirement of the Construction General Permit.

ODEQ: Oregon State Department of Environmental Quality

SEDIMENT: Any soil particles or solid material that have been moved by erosion from the place where they were formed.

TACKIFIER: A chemical or organic compound sprayed on loose soil to hold it in place.

STORMWATER POLLUTION PREVENTION PLAN (SWPPP): A site-specific written document that identifies potential sources of stormwater pollution, describes best management practices to reduce pollutants and the volume of stormwater discharges from a construction site and identifies procedures the operator will implement to comply with the terms and conditions of a general construction permit. The written plan describes how stormwater runoff at a construction site will be controlled, temporary erosion control measures, final stabilization measures, monitoring requirements, and contacts.

Storm Water Permitting Requirements

The Clean Water Act and associated federal regulations require nearly all construction operators engaged in clearing, grading, and excavating activities that **disturb one acre or more and have potential to discharge to surface waters or wetlands (including through storm drains and ditches)**, including smaller sites in a common plan of development or sale, to obtain coverage under a National Pollutant Discharge Elimination System (NPDES) permit for their stormwater discharges. Under the NPDES program, the U.S. Environmental Protection Agency (EPA) can authorize states to implement the federal requirements and issue stormwater permits. Washington, Idaho, and Oregon are authorized to issue their own permits for construction activities. In Washington, NPDES permits are issued by the

Department of Ecology (DOE), in Idaho they are issued by the Idaho Department of Environmental Quality (IDEQ), and in Oregon they are issued by the Department of Environmental Quality (DEQ). Refer to Table 1 for permitting requirements.

An Avista Environmental Permitting Specialist will help facilitate identification and acquisition of proper permits related to construction activities and development of Stormwater Pollution Prevention Plan's (SWPPP) when required. Refer to Table 1 and Table 2 in this specification for more details on permitting requirements. Avista may construct under another developer or third party contractor's permit when the permit specifies the inclusions of "utilities". The Avista Environmental Permitting Specialist can provide guidance when it is appropriate and acceptable to construction under a third party permit.

Gas construction activity undertaken in accordance with an approved Erosion and Sediment Control (ESC) Plan or permit must comply with the conditions of the plan and relevant permits.

Table 1 – Stormwater Erosion Control Guidance If Disturbing **Greater Than One Acre**

	Oregon	***Washington***	***Idaho***
SWPPP Required	Yes	Yes	Yes
ESC Required	Yes	No	No
NOI Required	Yes	Yes	Yes
NOT Required	Yes	Yes	Yes
Permit fees	Yes	Yes	No
Certified Inspector Needed	Yes	Yes	Yes
Land Use Compatibility Statement Required	Yes	No	No
State Environmental Policy Act (SEPA) Submission Required	No	Yes	No
Newspaper publication	Yes, DEQ does the notification >5 acres	Yes, once each week for 2 weeks. Applicant does notification	No, after filing NOI, construction can start
Permit name	1200 C Permit	General Construction Permit	General Construction Permit
File online	No	Yes	Yes
File hard copy	Yes	No	Yes
Governing jurisdiction	DEQ and the Rogue Valley Sewer District	DOE	IDEQ
Documentation stored	3 years minimum	3 years minimum	Not mentioned
Processing time	30-60 days	60 days	14 days
Low Erosivity Waiver	No	Yes	Yes

- Idaho is under the jurisdiction of IDEQ.
- Oregon is under the jurisdiction of DEQ and Washington is under jurisdiction of DOE.
- Oregon has two jurisdictions that are the reviewing party depending on the location of the project.
- In Oregon, for projects greater than 20 acres in disturbance, an Oregon licensed professional is required to complete the ESC.
- In Washington, field inspectors (monitors) of the SWPPP are required to have their CESCL (Certified Erosion and Sediment Control Lead) certification.
- In Oregon, certification is required to inspect soil erosion control measures.
- Idaho has its own certification program for projects requiring a General Construction Permit. The program is called the Stormwater and Erosion Education Program (SEEP). Typically, EPA will require monitoring personnel in Idaho to be SEEP or CESCL certified.

Best Management Practices (BMPs)

In order to enhance sediment control activities at construction sites Best Management Practices (BMPs) shall be implemented for land disturbance construction activities regardless of land disturbance size as described in this section and Exhibit A. If the project will disturb one acre or more, contact the Avista Environmental Permitting Specialist as mentioned previously to get assistance with permitting and SWPPP development. **For projects where land disturbance will be less than one acre, it is still incumbent upon the construction crew and others involved to consider all potential BMPs and to implement those that would support good stewardship of the project site.** It is particularly important to protect drains and direct pathways that flow to a stream or water body.

Following is an overview of the four major BMP groupings and the specific individual BMPs that fall within the groupings. The more commonly used BMPs are underlined and further detailed at the end of this specification; however, BMPs are not limited to this list. Work in and near water typically requires environmental permitting and strict adherence to BMPs. Temporary BMPs should be removed after sites are stabilized. **Contact the Avista Environmental Permitting Specialist and Gas Engineering for further assistance in choosing the proper BMPs for a gas construction project.**

1. **Planning BMPs**
    - **Contractor Education** – Providing copies of the ESC / SWPPP / BMPs to crew leaders. Having discussions regarding sensitive areas to avoid during construction, reviewing spill response procedures, setting up regular meeting times, and providing contact information.
    - **Buffer Zone** – Protecting existing vegetation adjacent to the project provides a stabilized area which will help control erosion, protect water quality, and enhance aesthetic benefits.
    - **Phased Construction** – Scheduling the project to reduce the amount and duration of soil exposed to erosion effects of rain, wind, etc.
    - **Clearing Limits** – Clearing the smallest area practical for the shortest time possible to complete the project.
    - **Perimeter Control** – Doing prior planning and implementing any sediment or erosion control BMP at the perimeter of the project to prevent sedimentation damage to the construction site or nearby property.
    - **Source Control** – Designing material storage and handling practices to prevent or reduce the discharge of pollutants into groundwater systems. Some examples are minimizing the storage of hazardous material on site, storing such materials in designated areas, installing temporary secondary containment, and conducting regular inspections.
    - **Stockpile Management** – Designing procedures to eliminate or reduce air and stormwater pollution from stockpiles of soil, paving materials, rubble, and the like. Process may involve some type of perimeter sediment barrier or be as simple as covering the stockpile with tarps or other protective means.
    - **Concrete Washout** – Designating a containment area for washout of cement truck delivery chutes and related equipment.
    - **Temporary Restrooms** – Doing prior planning to order and use temporary restroom facilities (i.e. Porta Potties).
    - **Stabilized Construction Entrance / Exit** – Establishing an area to minimize the tracking of mud and dirt onto nearby roads.

2. **Erosion Control BMPs**
    - **Slope Roughening** –Typically involves forming horizontal depressions along a construction slope with tracked or treaded equipment to form grooves that are perpendicular to the slope. This method stabilizes soils and reduces runoff velocity, encourages the growth of vegetation and trap some sediment.
    - **Mulching** – A temporary measure stabilizing soil and controlling erosion by placing a material like straw, grass, hay, compost, wood chips, or wood fibers on top of or incorporated into the soil surface.
    - **Hydromulching** – Similar to mulching except the mixing of a tackifier is combined to the mulch and water to form a slurry mix that is then broadcast on the soil surface to help ensure the mulch stays in place.
    - **Hydroseeding** – Similar to hydromulching that typically consists of applying a mixture of mulch fiber, grass seed, fertilizer, and a stabilizing tackifier to the soil surface.
    - **Erosion Control Blankets** – Installing a porous net or fibrous sheet mats that are then placed over the ground surface to stabilize slopes and control erosion.
    - **Dust Control** – Controlling dust pollution by any method such as water sprinkling, vegetative covering, tackifier installing, or surface roughening. Water should be obtained through an approved source and may not be withdrawn from water bodies without proper water rights or permits.
3. **Sediment Control BMPs**
    - **Vegetative Buffer Strip** – Using a living sediment barrier that consists of a gently sloping area of vegetative cover that runoff water flows through before entering a water feature. This buffer area may be an undisturbed strip of natural vegetation or a graded and planted area.
    - **Sediment Trap / Basin** – Constructing a containment area formed by excavation and/or embankment to intercept and retain sediment-laden runoff. The trap / basin must be large enough to allow most of the sediment to settle out and consequently are usually professionally designed.
    - **Silt Fence** – Using a temporary sediment barrier consisting of a filter fabric stretched and attached to supporting posts. Silt fences function by impounding water and slowly releasing it, allowing sediment to settle out and collect behind (upstream of) the fence.
    - **Fiber Roll / Straw Wattle** – Using a temporary sediment barrier that consists of straw, flax, coconut fiber, compost, or other similar materials bound into a biodegradable tubular casing. When properly placed at the toe and on the face of slopes, they intercept runoff, shorten slope length, decrease flow velocity, and trap sediment.
    - **Inlet Protection** – Using temporary devices (wattles, sediment fences, etc.) constructed to improve the quality of water being discharged to dry wells, drop inlets, or catch basins by pooling sediment-laden runoff and thereby increasing settling time.
4. **Run-off Control BMPs**
    - **Swales and Dikes** – Installing a temporary channel to prevent runoff from entering disturbed areas by intercepting and diverting it to a stabilized outlet or a sediment-trapping device.
    - **Grassy Swales** – Designing grassed shallow depressions in the earth constructed to hold stormwater while the grass and underlying soil and rock filter out various pollutants.
    - **Check Dams** – Constructing a small dam of rocks, logs, or brush and located in an open channel, swale, or drainage area in order to reduce or eliminate excessive erosion by reducing runoff velocity.
    - **Slope Drains** – Using a device to transport concentrated runoff from the top to the bottom of a slope that is at high risk for or has already been damaged by erosion without further damaging the slope.

- **Outlet Protection** – Installing various forms of protection (rock, riprap, etc.) at the outlets of pipes, culverts, catch basins, sediment basins, etc. where the velocity of water flow may cause erosion.
- **Terracing** – Constructing an earth embankment or ridge-and-channel arrangement along the face of a slope at regular intervals that serves to reduce erosion by capturing surface runoff and directing it to a stable outlet at a speed that minimizes erosion.

Table 2 – Construction Activities, Typical Governing Agencies and Associated Permits

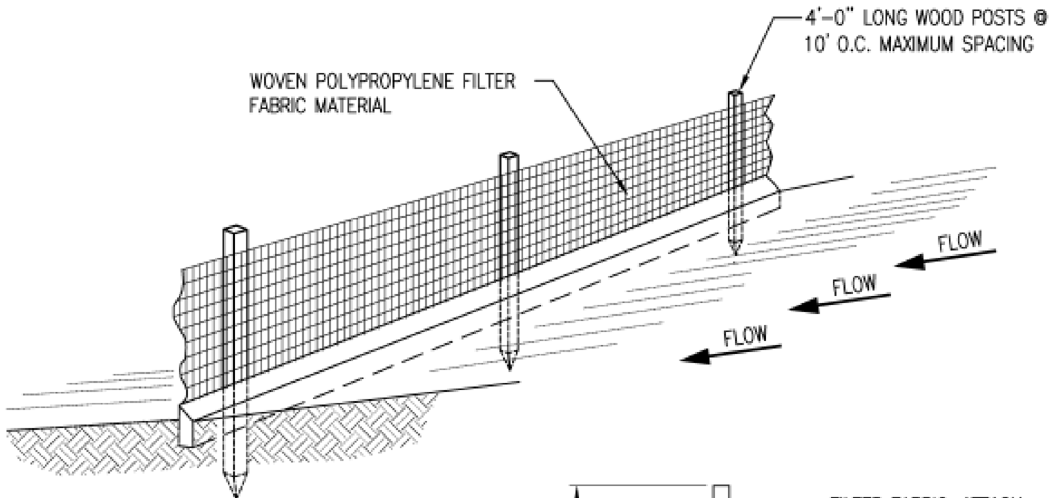
Construction Activity	Permit – Category	Governing Agency	Location	Permit	Notes
Land Disturbance	Erosion Control	ID - IDEQ	ID Lands	General Construction Permit SWPPP (Storm Water Pollution Prevention Plan)	Required for disturbance of land > 1 Acre and potential to discharge to surface water or wetlands. Permit will include BMP's.
Land Disturbance	Erosion Control	WA – DOE	WA Lands	General Construction Permit SWPPP (Storm Water Pollution Prevention Plan)	Required for disturbance of land =/> 1 Acre and potential discharge to surface water or wetlands. Permit will include BMP's.
Land Disturbance	Erosion Control	OR – DEQ	OR Lands	NPDES - 1200C	Required for disturbance of land > 1 Acre and potential to discharge to surface water or wetlands. Permit will include BMP's.
Land Disturbance	Navigable waters under COE jurisdiction.	Army Corp. of Engineers (COE)	ID, OR, WA	Section 10	Required to cross over or under the navigable waters
Wetland Disturbance	Critical Area Permit Process	Army Corp. of Engineers (COE)	Federal wetlands and Lands classified by Army Corp.	COE 404 Permit	Required to disturb or discharge into a wetland
Wetland Disturbance	Critical Area Permit Process	WA - Local Jurisdiction, City or County	Non-Federal wetlands	Local Jurisdictional Permit	Local jurisdictions follow WA-DOE guidance
Wetland Disturbance	Critical Area Permit Process	OR - Division of Lands and/or Local Jurisdiction (City or County)	Non-Federal wetlands	Permit	Work may require a permit from Local Jurisdiction (City or County) and a Division of Lands Permit. Check w/ Local Jurisdictions.
Wetland Disturbance	Critical Area Permit Process	ID - DEQ	Non-Federal Lands	Permit	
Flood Plain Disturbance	Critical Area Permit Process	City or County	City or County Lands	No-Rise Certificate or Permit	City and County jurisdictions implement FEMA rules
Steep Slopes Disturbance	Critical Area Permit Process	City or County	City or County Lands	Permit from Governing Jurisdiction	Governing rules follow local ordinances. Applies to disturbance of steep slopes.
Geological Hazards	Critical Area Permit Process	City or County	City or County Lands	Permit from Governing Jurisdiction	Governing rules follow local ordinances. Applies to disturbance of geological formations. Ex. Hot Springs, Earthquake Zones, Unstable Soils, etc.

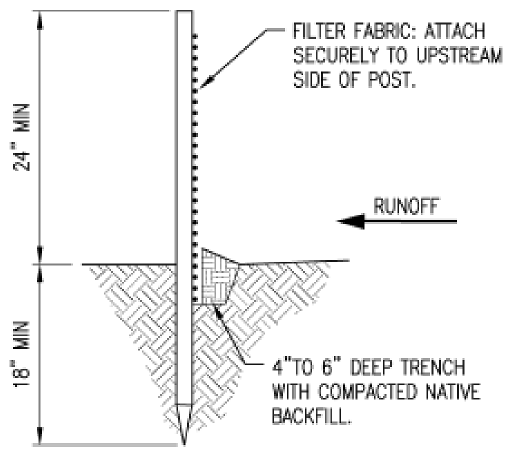
Table 2 – Construction Activities, Typical Governing Agencies and Associated Permits (cont.)

Construction Activity	Permit – Category	Governing Agency	Location	Permit	Notes
Cultural Resources Review	Local, State or Federal Permit Process	State Historic Preservation Office	All Lands	Section 106 Permit	Required for disturbance of known sites.
Grading / Filling	Grading / Site Disturbance Permit and ESC Plan	City or County	City or County Lands	Permit from Governing Jurisdiction	Required when changing grade and movement of soil. Governing jurisdiction determines the amount of soil when a permit is required.
Bores - Initiated above High Water Mark or work within buffer zone of waterways.	HPA or SEPA	WA - Local Jurisdiction processes the SEPA. WDF issues the HPA	Bores Under Water Features	SEPA (State Environmental Policy Act) and HPA (Hydraulic Project Approval w/ Washington Fish and Wildlife.	Required for work within buffer zone of waterways. Buffer zone size varies on type of waterway.
Bores - Initiated above High Water Mark		ID - Dept. of Lands	Bores on private property under water bodies.	Easement	
Bores - Initiated above High Water Mark		ID - Idaho Dept. of Water Resources	Bores under land not covered by Dept. of Lands.	Stream alteration permit.	
Bores - Initiated above High Water Mark		OR - No Permit Required unless under Section 10 Waters			No permit required. Courtesy notification to Department of Fish and Wildlife.
Bores Initiated below High Water Mark, Working in stream bed, or under Section 10 Waters		WA/ID/OR - Army Corp. of Engineers	All lands below high water mark or Section 10 Waters	Section 10 Permit	
Flood Plain Disturbance	Critical Area Permit Process	City or County	City or County Lands	No-Rise Certificate or Permit	City and County jurisdictions implement FEMA rules
Construction Activities	Fire Restrictions	ID - Department of Lands	Required on all Public and Private lands	Exemption Permit Available	Required in hot dry weather.
Construction Activities	Fire Restrictions	WA - Local fire districts		Exemption Permit Available	Required in hot dry weather.
Construction Activities	Fire Restrictions	OR - Roseburg Fire Protection Association or Local fire districts		Exemption Permit Available	Required in hot dry weather.
Construction Activities	Shoreline Permit	WA	Construct within 200' of covered waters	Permit	Covered waters include but are not limited to: Spokane River, Latah Creek, Colville River, Pend Oreille River.
Flood Plain Disturbance	Critical Area Permit Process	City or County	City or County Lands	No-Rise Certificate or Permit	City and County jurisdictions implement FEMA rules

Exhibit A – Common BMPs and How to Implement

1. **Silt Fence Sediment Control BMP**





NOTE: FILTER FABRIC FENCES SHALL BE INSTALLED AND IN WORKING CONDITION PRIOR TO ANY GROUND DISTURBANCE.

MAINTENANCE STANDARDS:

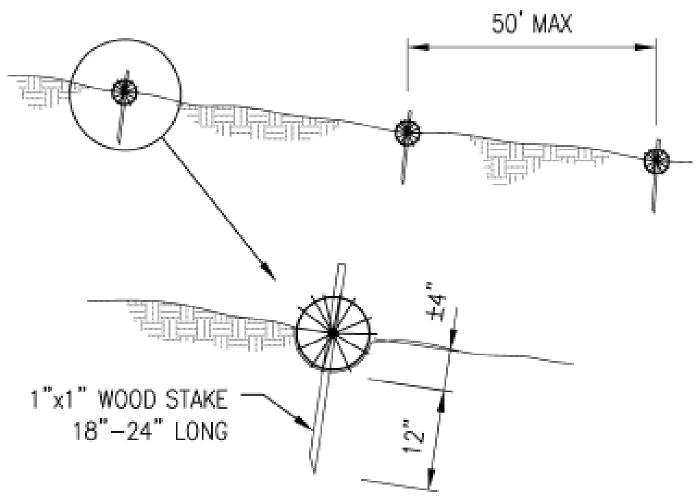
1. SILT FENCES AND FILTER BARRIERS SHALL BE INSPECTED IMMEDIATELY AFTER EACH RAINFALL AND AT LEAST DAILY DURING PROLONGED RAINFALL. ANY REQUIRED REPAIRS SHALL BE MADE IMMEDIATELY.
2. IF CONCENTRATED FLOWS ARE EVIDENT UPHILL OF THE FENCE, THEY MUST BE INTERCEPTED AND CONVEYED TO A SEDIMENT POND.
3. IT IS IMPORTANT TO CHECK THE UPHILL SIDE OF THE FENCE FOR SIGNS OF THE FENCE CLOGGING AND ACTING AS A BARRIER TO FLOW AND THEN CAUSING CHANNELIZATION OF FLOWS PARALLEL TO THE FENCE. IF THIS OCCURS, REPLACE THE FENCE OR REMOVE THE TRAPPED SEDIMENT.
4. SEDIMENT DEPOSITS SHALL EITHER BE REMOVED WHEN THE DEPOSIT REACHES APPROXIMATELY ONE-THIRD THE HEIGHT OF THE SILT FENCE, OR A SECOND SILT FENCE SHALL BE INSTALLED.
5. IF THE FILTER FABRIC (GEOTEXTILE) IS DAMAGED OR DETERIORATED, IT SHALL BE REPLACED IMMEDIATELY.

-

SILT FENCE

NOT TO SCALE

2. **Fiber Roll / Straw Wattle Sediment Control BMP**



SECTION

NOTES

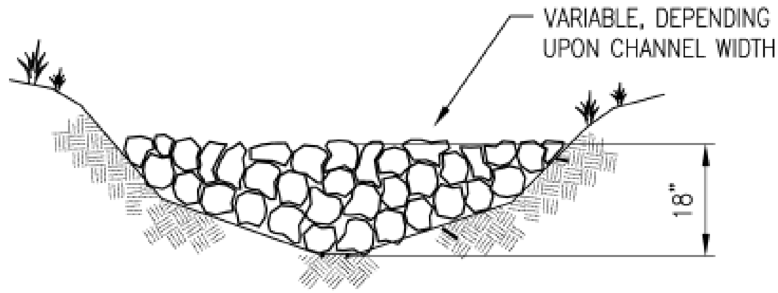
1. STRAW WATTLES TO BE 8" DIAMETER AND 20' TO 30' LONG.
2. DIG 4"x9" TRENCH TO RECEIVE WATTLE. TRENCH SHOULD FOLLOW CONTOUR OF SLOPE. BUTT ADJACENT WATTLES TIGHTLY.
3. STAKE TO BE SPACED 8" FROM EACH END AND NOT MORE THAN 6-FT O.C. DRIVE STAKES THROUGH THE CENTER OF THE WATTLE AND PERPENDICULAR TO SLOPE LEAVING 2"-3" ABOVE THE TOP OF WATTLE.

-

STRAW WATTLE

NOT TO SCALE

3. **Rock Check Dam Run-off Control BMP**



ELEVATION

NOTES

1. USE ROCKS 3" TO 8" IN SIZE FOR CHECK DAM.
2. PLACE ROCKS SO DAM IS PERPENDICULAR TO THE FLOW . USE ROCKS OR FILTER FABRIC TO FILL ANY GAPS AND TAMP BACKFILL MATERIAL TO PREVENT EROSION OR FLOW AROUND DAM.
3. HEIGHT SHALL NOT EXCEED 18".
4. INSPECT AFTER EACH SIGNIFICANT STORM, MAINTAIN AND REPAIR AS NEEDED.

ROCK CHECK DAM

NOT TO SCALE

3.44 EXPOSED PIPE EVALUATION

SCOPE:

To establish uniform procedures for evaluating steel and plastic pipelines that are exposed that were previously buried.

REGULATORY REQUIREMENTS:

§192.459, §192.475(b), §192.491, §192.1007(a)(1)(2)(3)

WAC 480-93-110(1), 480-93-110(6)(7)(8)

CORRESPONDING STANDARDS:

Spec. 3.12, Pipe Installation – Steel Mains
Spec. 3.13, Pipe Installation – Plastic (Polyethylene) Mains
Spec. 3.15, Backfilling and Trenching
Spec. 3.32, Repair of Steel Pipe
Spec. 3.33, Repair of Plastic (Polyethylene) Pipe
Spec. 4.42, Distribution Integrity Management Program
Spec. 5.11, Leak Survey
Spec. 5.14, Cathodic Protection Maintenance

General

When buried steel or plastic pipe is exposed an Exposed Piping Inspection Report (paper form N-2534 or electronic version of this report form) shall be completed in accordance with this standard. (Note: It is only necessary to complete an Exposed Piping Inspection Report when a gas carrying pipe is exposed).

An Exposed Piping Inspection Report form is not necessary for the following conditions:

- Casings or conduits (including plastic pipe in galvanized steel with service head adapter) or anodeless risers when no pipe is exposed.
- Pipe that has been abandoned or is in the process of being abandoned.
- Anodeless risers or risers with a service head adapter.
- Portions of risers that are aboveground and any other aboveground piping.
- Buried riser piping that is not exposed.

When retiring a steel service with a low cathodic read, the cathodic read recorded on the Exposed Piping Inspection Report for the main should be taken after the service being retired has been disconnected from the main.

The Exposed Piping Inspection Report is to be used to document both steel and plastic (PE) pipeline facility information about each exposure of pipe that will remain a gas carrying pipe. The job-related information and location shall be identified as detailed on the report. Applicable sections consistent with the material exposed (Steel or Plastic) shall be completed. For electronic orders where a CP low read is reported, field personnel should include the centerline measurements of the exposure in the comments section.

External Examination Plastic Pipe

The appropriate section of the Exposed Piping Inspection Report shall be used to capture information about each exposure of pipe, including the external pipe information, the as-found condition of the pipe, and the installation conditions. Specific information to be captured includes but is not limited to:

- Pipe material
- Pipe manufacturer
- Manufacture date and lot number
- Pipe color
- External pipe condition
- Internal pipe condition (as applicable)
- Products found inside pipe or on inside pipe wall
- As-found soil in contact with the pipe
- As-left soil type in contact with the pipe
- If a previous squeeze-off location is present in the exposed area for PE material
- If the pipe was squeezed during the current exposure
- If contaminated soil is present (Contaminated soil means the exposed soil smells of petroleum.)

If the print line or information is not readable, then check the appropriate boxes that indicate "Unidentifiable". This indicates that an attempt was made to capture this information but that it was not readable.

Note: If during the exposure, the tracer wire is found to be separated from the pipe, the tracer wire shall be relocated next to the plastic pipe and in a straight line to facilitate accurate pipe locating.

Examining Buried Steel and Pipe Coating

When a buried steel pipeline is exposed, it must be examined for evidence of external corrosion and coating deterioration. The inspection includes noting the type of pipe coating and the coating bond condition upon exposure, condition of external pipe if the coating has been removed, and documentation of rust and pitting. If pitting is found, it shall be measured with a pit gauge and the depth and width of the pitting shall be noted in the Exposed Piping Inspection Report form. The pit depth shall be measured in decimal inches, e.g., 0.050-inches. The width of the pit shall be recorded in fractions of inches in 16^{th} inch increments, for example, 1-3/16-inches.

Remedial action must be taken to the extent required, as referenced in the repair charts found in Specification 3.32, Repair of Steel. When corrosion is found and it extends beyond what is exposed, then the adjacent pipe must also be exposed and investigated to determine to what extent corrosion exists. Pipe shall further be exposed until at least 3 feet of adjacent pipe is found to be corrosion-free.

A pipe-to-soil read shall be taken and recorded when the coating needs to be repaired or removed. This information shall be recorded on the Exposed Piping Inspection Report. Refer to Pipe-to-Soil Procedures in Specification 5.14, Cathodic Protection for details. (Note: A pipe-to-soil read is not needed on risers if no below ground riser piping is exposed.)

Examining Buried Portion of Steel Risers

When soil is removed from around a buried steel carrier riser, an Exposed Piping Inspection Report is required. This does not include anodeless risers or risers with a service head adapter. (Note: it is not necessary to fill out an Exposed Pipe Report for the part of the riser that is aboveground. If no buried riser piping is exposed, no Exposed Piping Inspection Report is needed.)

Field personnel need to remove the soil around a steel carrier pipe riser where there is no wrap or poorly bonded wrap that comes aboveground. Dig until well bonded wrap is found and then rewrap it to above grade level per the requirements of Specification 3.12, Steel Mains, "Tape Wrap." This includes anytime field personnel are digging up around the riser below grade level. If there is pipe wrap that comes above grade and the field employee is only brushing back built-up dirt or debris back to grade level, then no Exposed Piping Inspection Report or pipe-to-soil read is required.

If the riser type cannot be determined, the riser shall be dug up and exposed until the riser type is determined.

Exposed riser information to be documented on the Exposed Piping Inspection Report form includes:

- Depth in inches that the soil was removed from around the riser.
- Length exposed will most likely be the same as the depth in inches; however, this is recorded in feet, i.e., 1 inch = 0.08 of a foot, 2 inches = 0.17 of a foot, 3 inches = 0.25 of a foot, etc.
- Coating type for steel risers that have a painted coating; choose "Other," "Riser/gray paint," or "Riser/green paint," etc. Otherwise, choose one of the appropriate coatings.

<u>Coating Bond Condition Classifications:</u>
(If bare pipe is noted in the "coating type" section, then no coating bond information is required since no coating is present.)

Bonded: The coating provides a continuous barrier, and no defects are observed.

Unbonded: The coating has degraded to the point that areas of corrosion are detected on the surface, coating holidays exist, or the coating is visibly dis-bonded from the surface of the pipe. (Note: A pipe-to-soil read is required on the Exposed Piping Inspection Report form for un-bonded conditions.)

<u>Soil Type Descriptions:</u>

Sand: A sedimentary material that is finer than granule and coarser than silt.

Loam: Soil that has no or few rocks or pebbles but has some peat or peat-like elements in the soil.

Clay: Very fine soil that becomes slimy or plastic when mixed with water and compacts tightly and is hard to remove from the ditch and boots.

Rocky: Soil that contains rock, angular or rounded, in substantial concentration.

Concrete/Grout: Material composed of concrete as well as other cementitious materials such as fly ash, slag cement, or aggregate materials mixed with water and allowed to harden.

Controlled-Density Fill (CDF): A self-compacting, flowable cementitious material used primarily as a backfill in lieu of compacted backfill.

Low Cathodic Protection (CP) Read Identified

If a low read is found, it shall be reported to the CP Low Field Reading Reporting Hotline as soon as possible. If the report is not submitted via the mobile computer, then Fax or email a picture of the completed paper Exposed Piping Inspection Report (form N-2534) to the following:

Low Read Hotline:	**Primary:** 877-800-3770	**Alternate:** 509-495-2258
Fax or Email to:	**Fax:** 509-777-9458	**Email:** CPLowRead@AvistaCorp.com

The hotline will no longer provide prompts for the required information. When calling the hotline be prepared to provide the following information:

- First and last name
- State the cathodic protection read was taken in (ID, OR, or WA)
- The date (month, day, and year) the low cathodic protection read was taken
- Address or location where the read was taken, be as specific as possible
- City
- Pipe-to-soil read
- Any additional comments

Internal Steel Pipe Examination

When steel pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion (rust or pitting) and if the inside wall is clean, dirty, or oily, and if there are puddles of water, oil, or black sludge in the pipe. If pitting is found, it shall be measured with a pit gauge and the depth and width of the pitting shall be noted in the appropriate section of the Exposed Piping Inspection Report form.

If internal corrosion is found refer to “Internal Corrosion Control” in Specification 5.14, Cathodic Protection Maintenance.

Internal PE Pipe Examination

When pipe is removed from a pipeline or cut apart for any reason, the internal surface of the plastic pipe shall be inspected to determine if the inside wall is clean, dirty, or oily, and if there are puddles of water, oil, or black sludge in the pipe.

Compliance

The exposed pipe process shall utilize both electronic and paper documents to capture gas pipe field data as presented on the Exposed Piping Inspection Report form. Information captured on the paper Exposed Piping Inspection Report form shall be recorded electronically within the Avista document retention system.

Records Retention

Avista shall maintain the exposed pipe records for the life of the pipeline facility or 10 years whichever is longer.

Examples of Pipe Exposures

Below are examples of when an Exposed Piping Inspection Report form is required to be filled out (multiple Exposed Piping Inspection Report forms may be required depending on what is exposed in the ditch or bell hole):

- Where multiple mainline coating types for steel pipe exist within the open ditch, an Exposed Piping Inspection Report is required for each coating type and an additional Report is required if the condition of the pipe under the coating changes. An additional Exposed Piping Inspection Report is not required for a change in coating type for the weld joint or a fitting, only for a change in the mainline pipe coating.
- Where pipe diameter changes within the open ditch.
- On either side of a dresser fitting or isolation fitting within the open ditch.
- On a pipeline that remains energized within the open ditch for a pipe abandonment, replacement, or removal. (Including service stubs; no minimum length is exempt).
- Where each service lateral is exposed within the open ditch.
- Steel gas carrying risers that are uncovered below grade level.

4.0 OPERATIONS

4.11 CONTINUING SURVEILLANCE

SCOPE:

To establish a procedure for continuous monitoring of Avista's pipelines and facilities in order to determine the extent of changes in class locations, changes or trends in leakage history, changes or trends in corrosion or cathodic protection requirements, updating and correcting mapping data, and identification of other unusual operating or maintenance requirements.

REGULATORY REQUIREMENTS:

§192.465, §192.481, §192.605, §192.609, §192.611, §192.613, §192.619, §192.620, §192.705, §192.706, §192.721, §192.723

WAC 480-93-017, 480-93-018, 480-93-180, 480-93-187, 480-93-188, 480-93-200

CORRESPONDING STANDARDS:

Spec. 4.14, Recurring Reporting Requirements
Spec. 4.31, Operator Qualification
Spec. 5.11, Leak Survey
Spec. 5.14, Cathodic Protection Maintenance
Spec. 5.15, Pipeline Patrolling and Pipeline Markers

General

The Maintenance and Operations sections of the Gas Standards Manual comprise Avista's Continuing Surveillance program. When maintenance is performed, it allows an opportunity for continuous monitoring of procedures, pipelines, and facilities.

Information Analysis and Responsibilities

Operations Managers shall be responsible for making initial determinations regarding conditions or situations on pipelines and facilities that require a special analysis or possible action. Hazardous or potentially hazardous conditions that may affect life or property shall be corrected immediately upon discovery or as soon as possible under regulatory code and company standards. Employees in each construction area shall receive training to be able to recognize conditions that may be subject to safety related reporting requirements or that may require action to prevent the formation of an immediate hazard.

Information pertaining to potentially hazardous conditions, especially those that indicate a trend or system-wide problem, shall be reported, and discussed with appropriate Gas Engineering personnel and the Gas Pipeline Integrity Program Manager. An analysis shall be performed to determine if mitigating action should be taken to forestall a hazardous situation. The review of this information should be conducted periodically. Consideration shall be given to using centralized maps, map overlays, etc. to visually analyze areas of corrosion, leakage, soil subsidence, failures, and other unusual conditions.

As soon as it is determined that a trend has possibly developed in such above-mentioned conditions, Gas Engineering shall initiate additional surveys in order to make a final determination on what action is appropriate.

The required mitigation shall be communicated to the affected construction area as soon as practicable. In cases where a segment of pipeline is involved, a program to recondition or phase out the segment shall be initiated. If the segment cannot be reconditioned or phased out, the MAOP of that pipeline system shall be reduced per §192.619 and §192.620. In the case where other gas facilities are involved, the appropriate repairs or replacements shall be completed as soon as possible.

Extreme Weather Event or Natural Disaster – Transmission Pipeline Facilities Inspection

Following an extreme weather event or natural disaster that has the likelihood of damaging pipeline facilities by scouring or movement of the soil surrounding the pipeline or movement of the pipeline itself, all potentially affected **transmission** pipeline facilities shall be inspected to detect conditions that could adversely affect the safe operation of the pipeline. The TIMP Program Manager will typically trigger this inspection following a severe weather event, but it can be initiated by Gas Engineering or local operations as well. The inspection should utilize the Gas Patrolling Report form (N-2629). The following are situations where inspections shall be performed:

- Flood that exceeds the river or creek high-water banks in the area of the pipeline
- Landslide in the area of the pipeline
- Earthquake in the area of the pipeline
- Above ground facilities in proximity to a forest fire

The requirements for the inspection are as follows:

1. Assess the nature of the event and the physical characteristics, operating conditions, location, and prior history of the affected pipeline in determining the appropriate method for performing the initial inspection to determine the extent of any damage and the need for any additional assessments.
2. The inspection must commence within 72 hours after the point in time that the affected area can be safely accessed by personnel and equipment, and the personnel and equipment required to perform the inspection are available. If an inspection cannot be commenced within 72 hours due to the unavailability of personnel or equipment, the PHMSA Region Director shall be notified as soon as practicable.
3. Prompt and appropriate remedial action shall be taken to ensure the safe operation of the pipeline based on the information obtained as a result of the inspection. Such actions might include, but are not limited to:
    a. Reducing the operating pressure or shutting down the pipeline;
    b. Modifying, repairing, or replacing any damaged pipeline facilities;
    c. Preventing, mitigating, or eliminating any unsafe conditions in the pipeline right-of-way;
    d. Performing additional patrols, surveys, tests, or inspections;
    e. Implementing emergency response activities with Federal, State, or local personnel; or
    f. Notifying the affected communities of the steps that can be taken to ensure public safety.

Map and Data Corrections

Occasionally data or mapping discrepancies are identified by field personnel and construction contractors. These discrepancies require an editor to make the map/data correction. Mapping and data corrections shall be submitted by the individual who identified and validated the discrepancy. Request for corrections should be submitted along with the information included on the “Map/Data Correction Form” (Form N-2672) to the appropriate office for editing. In Washington State, map corrections shall be completed within 6 months following the completion of field work. In Idaho and Oregon this is a best management practice.

4.12 SAFETY-RELATED CONDITIONS

SCOPE:

To establish procedures to be followed in the event that safety-related conditions are found to exist on Avista's pipelines or facilities that requires action and/or reporting under State or Federal guidelines.

REGULATORY REQUIREMENTS:

§191.3, §191.23, §191.25, §192.605

WAC 480-93-180, 480-93-200

CORRESPONDING STANDARDS:

Spec. 4.11, Continuing Surveillance
Spec. 5.14, Cathodic Protection Maintenance
Spec. 5.15, Pipeline Patrolling - Pipeline Markers

General

Gas operations employees shall be familiarized through review of this section with conditions and situations that constitute an actual or potential safety-related condition. Employees that discover such conditions shall report all pertinent facts to the applicable Operations Manager immediately. Gas Engineering shall then be notified so that they may make an evaluation and recommendations for correction or repair of the condition, as appropriate.

Corrective action shall be taken to eliminate or minimize any hazardous conditions that are discovered. Such actions shall include, but are not limited to:

- In the case of corrosion, reducing the operating pressure to a pressure commensurate with the strength of the pipe based on the actual remaining wall thickness.
- Repairing corroded pipe if the area of general corrosion is small.
- Replacing pipeline segments with corrosion pitting or general corrosion.
- Repairing or replacing facilities that may have failed or caused a pipeline pressure to exceed the MAOP, plus build-up.
- Shutting down any pipeline or facility where an immediate hazard exists.

Reporting of Safety-Related Conditions

Gas Engineering with the assistance of the Pipeline Safety Engineer shall assess and report (as necessary) the conditions found to exist on company facilities or pipelines that constitute an actual or potential safety-related condition as defined in §191.23.

The following safety-related conditions discovered on pipelines and facilities shall be reported:

- In the case of a pipeline operating at a hoop stress of 20 percent or more of specified minimum yield strength (SMYS), in which general corrosion has reduced the wall thickness to less than that required for the maximum allowable operating pressure (MAOP), and localized corrosion pitting exists to a degree where leakage might result.

- Unintended movement or abnormal loading by environmental causes, such as earthquake, landslides, or flooding, which impairs the serviceability of a pipeline.

- Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of SMYS.

- Any malfunction or operating error of pressure limiting or control devices that causes the pressure of a distribution pipeline to exceed its MAOP plus the allowable build-up.

- A leak in a pipeline that constitutes an emergency.

- Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.

- For transmission pipelines only, each exceedance of MAOP plus allowable build-up for operation of pressure limiting or control devices as specified in the applicable requirements of §192.201, §192.620(e), and §192.739.

Exceptions to Reporting Safety-Related Conditions

A report is <u>not</u> required for any safety-related condition that:

- Exists on a master meter system, a reporting-regulated gathering pipeline, or a customer-owned service line.

- Is an incident or results in an incident before the deadline for filing the safety-related condition report.

- Exists on a pipeline that is more than 220 yards (660 feet) from any building intended for human occupancy or outdoor place of assembly. *Exception: Reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway.*

- Is corrected by repair or replacement in accordance with applicable safety standards before the deadline for filing the safety-related conditions report. *Exceptions: Reports are required for transmission pipelines where corrosion has reduced the wall thickness to less than that required for the maximum allowable operating pressure, other than localized pitting on an effectively coated and cathodically protected pipeline. Reports are also required for transmission pipelines where there has been an exceedance of MAOP plus allowable build-up as discussed in the last bulleted item of the previous section.*

Filing of Safety-Related Condition Report

Each report of a safety-related condition must be filed (received by the Associate Administrator) in writing within 5 working days (not including Saturdays, Sundays, or Federal holidays) after the day a representative of the operator first determines that the condition exists, but not later than 10 working days after the day a representative of the operator discovers the condition. Separate conditions may be described on a single report if they are closely related.

Each report of a **gas transmission pipeline** MAOP exceedance meeting the requirements of criteria in the previous section, must be filed (received by the Associate Administrator) in writing within 5 calendar days of the exceedance.

The report shall be headed "Safety-Related Condition Report" and shall include the following information:

- Company name, principal address, and operator identification number (OPID). Avista's OPID is 31232.
- Date of the report.
- Name, job title, and business telephone number of person submitting the report.
- Name, job title, and business telephone number of person who determined that the condition exists.
- Date condition was discovered, and date condition was first determined to exist.
- Location of the condition, with reference to the State (and town, city, or county) and, as appropriate, nearest street address, survey station number, milepost, landmark, or name of pipeline.
- Description of the condition, including circumstances leading to its discovery, any significant effects of the condition on safety, and the name of the commodity transported or stored.
- The corrective action taken (including reduction of pressure or shutdown) before the report is submitted and the planned follow-up or future corrective action, including the anticipated schedule for starting and concluding such action.

Gas Engineering with assistance of the Pipeline Safety Engineer shall email or fax a copy of the Safety-Related Condition Report to the following email address or number:

InformationResourcesManager@dot.gov

Fax No. 202-366-7128

Copies of the Safety-Related Condition Report shall also be sent to the appropriate state agencies.

Recordkeeping

Records of Safety-Related Condition Reports, letters, and other documentation relating to the discovery, evaluation, and correction of safety-related conditions shall be retained for the life of the system.

4.13 DAMAGE PREVENTION PROGRAM

SCOPE:

To establish uniform procedures to prevent damage to Company pipeline facilities due to excavation or other related construction activities.

REGULATORY REQUIREMENTS:

§192.614, §192.615, §192.616, §192.707, §192.935, §196, §198

WAC 480-93-124, 480-93-200, 480-93-250

RCW 19.122

OAR 952

ID 55-22

CORRESPONDING STANDARDS:

Spec. 3.14, Pre-Check Layout and Inspection
Spec. 3.19, Trenchless Pipe Installation Methods
Spec. 3.44, Exposed Pipe Evaluation
Spec. 4.11, Continuing Surveillance
Spec. 4.14, Recurring Reporting Requirements
Spec. 5.14, Cathodic Protection Maintenance

General

Avista maintains and implements a Damage Prevention Program to educate contractors and the general public about gas pipelines in coordination with Avista's Public Awareness Program. The Damage Prevention Program includes procedures for:

- Notifying the public and contractors of the program's existence and purpose,
- Notifying the public and contractors as to how they can learn the location of pipeline facilities before excavation or construction activities commence,
- Providing a means of receiving and recording notification of planned excavation and construction activities,
- Providing the public and contractors information as to the type of temporary markings to be used to identify underground facilities and how to identify the markings, and
- Providing actual temporary physical marking of buried pipelines in areas of excavation or construction before activity begins.

For the purpose of this section, the term "excavation" shall include excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by either explosive or mechanical means, and other earth moving operations. The term "construction" shall apply to all other activities that could affect the integrity of Avista's gas pipelines or facilities.

Public Awareness Program

The Safety Department is responsible for the overall development, implementation, and maintenance of Avista's Public Awareness Program. The program identifies stakeholder audiences and associated lists, the message content per stakeholder, frequencies and methods of message delivery, a program evaluation process, and additional languages into which this media information should be translated.

The focus of Avista's Public Awareness Program is to raise the awareness of the presence of natural gas pipelines within its communities and educate stakeholders on the prevention and/or response actions to natural gas pipeline accidents. Avista's communication methods are through various media including, public service announcements, paid advertising, bill inserts, newspapers, magazines, mass mailings, online marketing, presentations, and events.

One Call systems may also provide appropriate information to contractors and the public through such means as television and radio advertising, bumper stickers, pamphlets, presentations, events, etc. The local operations managers should endeavor to use these means in addition to the Company programs. Additional detail is available in Avista's Public Awareness Plan, which is maintained by the Public Awareness Specialist.

The Damage Prevention Administrator, or other designated individual, is responsible to provide information on excavation damages to the Public Safety Specialist who manages the company's Public Awareness Program. This information includes detailed damage reports, excavator detail, damage trends, and other data that is beneficial to enhance Public Awareness mailing content and messaging.

Inspection and Protection of Pipelines after Railroad Accidents

Avista should inspect its gas pipeline facilities following railroad accidents and other significant events occurring within railroad right-of-way. Such inspection should include but is not limited to alerting rail operators and emergency responders of the presence, depth, and location of the pipelines to minimize the potential of damage to the facilities during clean-up and restoration activities. Avista's Safety Department has developed special communications materials for communication of this topic to known railroads and their agents in the Company's service territory. The name of the brochure is "Electric and Natural Gas Line Safety for Railroad Workers" (WA/ID) and "Natural Gas Line Safety for Railroad Workers" (OR).

One Call Notification System

A One Call notification system is where a utility locate request center, known as a One Call Center, receives a request from an excavator through one number (811 or www.811.com) for locating and marking of underground utility facilities in a planned excavation site. This system eliminates the need for duplicate calls requesting the same information from the different utilities or agencies affected. One Call Centers may provide a platform for members to discuss damages, facilitate planning, and to further improve the system. One Call Centers may collect information on damages and compile the results for distribution to the members.

In the instance that a One Call notification system is not available in a particular service district or in the event that such services are suspended or cancelled, the Company shall make provisions for notifying the public and contractors of the provisions of this Damage Prevention Program through coordination with Avista's External Communications Department and the local operations manager.

Requests for Locates Through One Call

In areas where One Call notification systems are available, a designated One Call Center will receive and process incoming requests regarding facility locations. A minimum of two (2) business days prior notice is required for locate requests. One Call Centers will normally retain records pertaining to locate requests, however, written requests for locates and supporting documentation shall be retained by Avista or their locating representative for a minimum of three (3) years. Requests for locates received by Company personnel shall be routed through the One Call Center to assure that notification is processed and sent to the appropriate designated Avista locator (contractor or in-house) based on the area and type of facility identified on the utility location request also known as a locate ticket. This also assures that proper documentation and records are kept for each locate ticket.

One Call Centers that Avista is a member of are:

- Bonner/Boundary/Shoshone/Benewah Counties, ID – Password Inc.
- Kootenai County, ID – One Call Concepts
- North Central Idaho – Dig Line
- Oregon – One Call Concepts
- Washington – One Call Concepts
- Montana (electric only) – One Call Concepts

Requesting Emergency Locates

Emergencies occur which do not allow two (2) working days to mark gas facilities. Requests for emergency locates should still be routed through the One Call system and facilities should be marked as soon as possible after being notified.

An EMERGENCY means any condition involving a clear and present danger to life, property, or a customer service outage. (In Oregon the definition includes interruption of essential public services and in Idaho the definition includes blockage of roads/transportation facilities that require immediate action).

If Avista is dealing with an emergency that requires excavation, a request for locates shall be made. If locates cannot be expedited and an alternative method of securing the situation is not feasible, then excavate using reasonable care.

Locating and Marking Avista Facilities

Individuals performing locates of Company gas facilities shall be properly trained in the use of the appropriate locating instrument, the use of Company maps, and shall be familiar with the state underground dig laws, and information and procedures contained herein. Locating of Avista's cathodic protection facilities should only be performed by trained and qualified Avista cathodic protection personnel.

Websites for State Underground Dig Laws:
Idaho:
https://legislature.idaho.gov/statutesrules/idstat/title55/t55ch22/

Oregon:
https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=4223

Washington:
http://apps.leg.wa.gov/rcw/default.aspx?cite=19.122

Upon receiving notification of proposed excavation or construction activity, or upon receipt of a utility location request, the following procedures shall be followed, in addition to the respective state's "Underground Dig" laws:

- Avista facilities shall be located and marked within two full business days (unless other documented arrangements have been made with the excavator) after the excavator notifies the One Call Center.
- Marking of facilities – Use a stripe approximately 18" long by approximately 2" wide. Stripe approximately every 10 to 15 feet and more frequently in areas where facilities turn, angle, junction, cross, etc. to indicate the location of the facilities. Marks should be carried slightly past the dig area. Use an arrow ">" to indicate the direction that the facility continues on and out of the dig area.
- Dotting with locating paint is acceptable in areas of decorative rock, hardscapes, and landscaped areas to minimize overspray on private property. Should be used in conjunction with flags if appropriate.
- Labeling for locate marks shall indicate company identification letters "AVA" for Avista, "GAS" "CP" "ELE" <u>"F/O"</u> for the type of facility, and diameter of the pipe or facility if it is greater than 2" in diameter. If the pipeline is considered high pressure, it shall also be indicated <u>with "HP"</u>. Example:

  AVA 4" HP GAS or **AVA 4" GAS or AVA CP**
- Placement of labeling should be on every lateral and approximately 50 feet apart or at a distance that the excavator can clearly see from one label to the next. This is extremely important where there may be multiples of the same type of utilities in the area with the same colored marks. (If there are short laterals off of the mainline that clearly show it is part of the gas line then labeling may not be necessary due to the shortness of the lateral.) Labeling also aids in identifying the utility lines for those individuals that are color blind.
- **In Oregon Only:** Abandoned facilities should be provided when possible (if known) to assist the excavator and reduce downtime when they come across an unmarked pipeline or cable. These facilities should be marked in the appropriate utility color with a capital letter "A" inside a circle along with the company identification letters AVA for Avista, the word GAS or CP, the pipe or facility size if known and greater than 2" in diameter. Example:

  A **AVA GAS 4"**
- If no facilities are in the area, the excavator or contractor shall be notified of this. Notification may either be by telephone, email, in person, or by painting "**NO AVA**" and the appropriate facility type (GAS, CP, <u>F/O</u> or ELE) on the ground surface at the proposed excavation or construction site. Physically marking the ground surface is the preferred method. The employee shall document how this information was communicated as part of the documentation above.
  - Example: **NO AVA GAS or NO AVA CP**
- When marking underground company gas pipelines and facilities, the locator shall use the following methods in the appropriate APWA utility color:
  a) **Spray paint.** Using paint intended for temporary marking of underground facilities, the locator shall indicate the presence of pipelines or other facilities using a striped line on the ground or road surface. Care should be taken to avoid getting paint on buildings, parked cars, sports courts, etc. <u>Mismarks should be removed immediately by overcoating with a neutral color.</u>
  b) **Polyethylene whiskers** may be used as an alternative method of marking where snow, ice, rain, or heavy traffic could make paint marking ineffective. Examples include dirt or gravel roadways, alleys or intersections, and parking areas or construction sites. Areas do not include residential properties or where indications of shallow gas lines would present danger to the facility with their use.

c) **Marking pin flags** should be used in addition to or as an alternative method of marking during inclement weather, in landscaped or grassy areas and areas of dead vegetation where visibility of paint (especially yellow) presents a problem as necessary.

d) **Marking stakes** may also be used where practical. Drive stakes into the ground surface at regular intervals so that the direction of the facility is easily discernible.

In each case of locating and marking company facilities, the locator shall take reasonable steps to assure that the excavator or contractor can properly identify the location markings.

If the locator cannot determine where the dig site or zone is, contact the excavator for clarification. If unable to contact the excavator, then locate the area based on the description on the locate ticket if there are no white marking indications or if the white markings are not complete or clear.

It is beneficial to meet with the excavator at the job site to clarify the exact location where the construction will take place. In unusual situations, some methods other than the above marking methods may be used such as offset markings/stakes.

A visual inspection shall be completed during the facility locating process. The primary reason for the visual inspection is to determine if there are facilities that are not on record or mapped, such as in new areas of construction. The visual inspection includes identification of access points and potential hazards as well as to assure that plant facilities shown on records match those of the site. Evidence of a facility not on a record/map includes but is not limited to valves, risers, meters, and vent pipes.

The locator shall document all facilities located on the locate request ticket, in a ticket management system, or on a daily log sheet. Documentation includes locate ticket number, name of locator, date and time locate was completed, conversation with excavators or homeowners, notes/comments indicating any changes to the described dig area as agreed upon by the requestor, and pictures showing Avista's utility mapping of the proposed dig area and the locate marks in case of a dispute. Photo documentation of utility markings should be oriented in-line with the utility path and include permanent background objects or structures for reference. Pictures should also capture the excavator's white markings.

When a request is made for "remarking" or "refreshing" of Avista's facilities, the request shall be treated as if it were a new locate request by connecting to the facilities and locating it out to validate whether or not there has been a change since the last time it was located.

If in the course of locating and marking, a locating technician discovers a natural gas leak, they shall call Avista at 1-800-227-9187 to report the leak.

HARD TO LOCATE FACILITIES PROCESS:

Every hard to locate pipeline situation is different. There is a difference between steel and plastic and the success to locating and or finding them. The length of the hard to locate (or un-locatable) pipe is also a big factor. A steel stub or end of main are more likely to "tone" depending on the length, whereas a plastic stub or end of main are typically extremely difficult to locate. Following is the process a locating technician should follow to locate such facilities:

- The locating technician checks to see if a marker ball is present.
- The locating technician direct connects using the appropriate frequency and power setting to obtain continuity. Neighboring hook up locations should be accessed if a sufficient signal cannot be obtained at the first location. A higher frequency may need to be used to push a signal onto the facility that is hard to locate.

- If a proper signal cannot be obtained to locate the gas facility, the locating technician should communicate with the excavator to let them know about the hard to locate facility and to determine if the facility will be in their dig zone. This communication should be documented with the locate ticket.
- In WASHINGTON RCW 19.122.030 (3)(b) and (4)(b)(iii): A GIS map of the area showing the location of the hard to locate (un-locatable) facility with Avista's disclaimer on it should be given to the excavator within the two (2) business days. In the proposed construction area, spray paint a yellow triangle mark on the ground pointing in the direction where the facility is un-locatable.
- In IDAHO ID CODE 55-2205(2) If there are identified but un-locatable facilities, they shall be marked using the best available information within the two (2) business days. Spray paint a triangle mark on the ground pointing in the direction where the facility becomes un-locatable. If there is no available information, then also include "Length ?" if it is a stub or end of main. (This indicates that we know there is a facility here but do not know where the facility ends.)
- If the facility is in the dig zone, then the locating technician either turns the section that they cannot locate over to a lead technician or to Avista* if there is no lead technician assigned to the area such as in the smaller districts.
- As-built research is then conducted for the hard to locate (un-locatable) facility to determine if there are centerline measurements that can be used to mark the facility. The facilities should be marked with the actual measurements (i.e., 395' CL with an arrow showing the direction of which street centerline is being referenced). The excavator should then be notified that a record was used to locate the facility and to dig with care.
- If there is no record of the facility or the record does not provide sufficient information for a measurement, then follow the additional actions seen below.

*When a contract locator notifies Avista's local office of a hard to locate (un-locatable) facility, the local Avista operations office shall take additional actions to identify the location of the facilities within the prescribed timeline of the locate ticket unless **documented** arrangements with the excavator have been made.

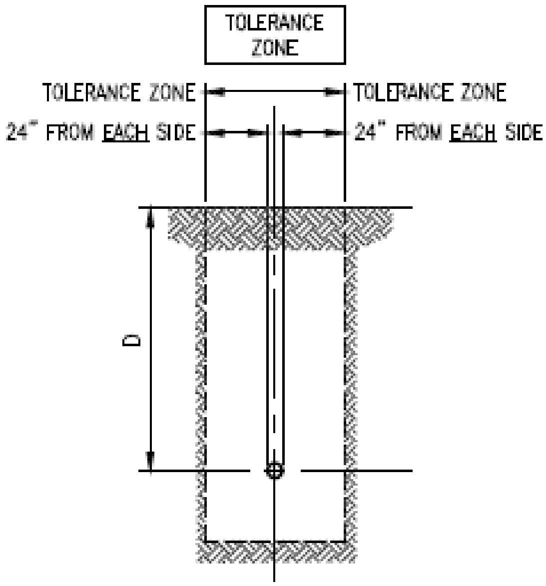
Additional actions may include but are not limited to: (Contact Damage Prevention Program Administrator for guidance if necessary)

1. Review of maps, main, service line, or stub card as-built documents.
2. Potholing the facilities to try to find and fix a broken wire.
3. Coordinate with the excavator to minimize the potential for damage to Avista's facilities by utilizing such techniques that include but are not limited to the following:
    a. Having field personnel stand-by while excavating across the facility.
    b. Identify the location of the facility by assisting with hand excavating.
    c. Employ other locating techniques as available and if time permits.
4. Facilities with broken wires, if not repaired through actions listed above, should have a job made up to have the broken wire repaired when practical.
5. When facilities are located, centerline measurements should be captured and mapped in GIS for use for future locating.
6. Installation of a marker ball to aid in future locating of facilities such as end of main, end of stub, valves, or other locations where it makes sense at the time of an open ditch.

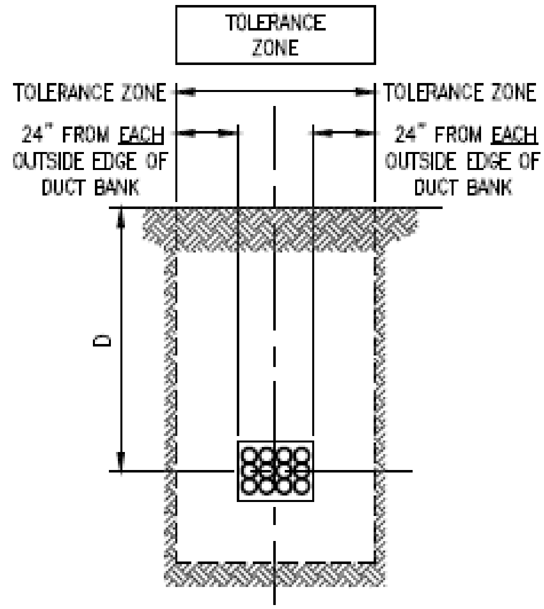
Tolerance Zone

A locator is required to locate to a "reasonable accuracy" which means a location within 24 inches of the outside lateral dimensions of <u>both sides</u> of an underground facility (also known as a tolerance zone).

TOLERANCE ZONE/REASONABLE ACCURACY ZONE DIAGRAMS - WA/ID:



SINGLE SUBSURFACE FACILITY

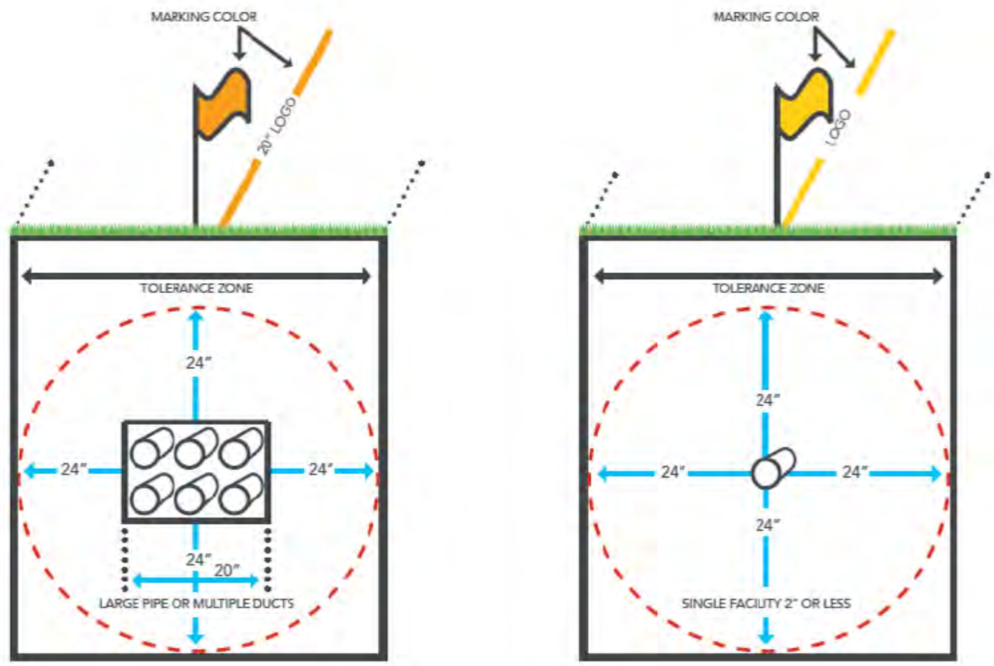


MULTIPLE SUBSURFACE FACILITIES

In the "reasonable accuracy zone" or "tolerance zone" an excavator is required to excavate with hand tools or non-invasive methods (in WA it is using reasonable care) within this zone to determine the exact or precise location of the marked utility.

TOLERANCE ZONE DIAGRAM – OREGON

Tolerance zone means the area within 24 inches surrounding the outside dimensions of <u>all sides</u> of an underground facility. Employ hand tools or other non-invasive methods either to determine the exact location of the underground facility or down to 24 inches beyond the depth of intended excavation within 24 inches of the outside dimensions of a marked underground facility.



Recordkeeping

Written requests for locates and supporting documentation shall be retained by Avista or their locating representative for a minimum of three (3) years.

APWA Uniform Color Codes for Marking

Listed below are American Public Works Association (APWA) uniform color codes used to mark utility locations. These color codes shall be adhered to unless it conflicts with local codes or practices.

Red	Electric Power Lines, Cables or Conduit, Lighting Cables, cathodic protection
Yellow	Gas, Oil, Steam, Petroleum, Hazardous Liquid, Gaseous Materials
Orange	Communications, Cable TV, Alarm or Signal Lines, Cables or Conduits, Fiber
Blue	Potable Water
Green	Sewers, Drainage Facilities or Other Drain Lines
Pink	Temporary Survey Markings
Purple	Slurry, Irrigation, and Reclaimed Water
White	Proposed Excavation Area

Excavator Responsibilities for Safe Digging

The general responsibilities of an excavator for safe digging and prevention of excavation damages are outlined below. (Refer to respective state dig laws for specific requirements)

- Premark the excavation site in white.
- Request locates at least two (2) business days before beginning an excavation.
- Do not begin excavation until all known utilities are marked or have been cleared (utilities are listed on the locate ticket in some states their contact information is also included).
- Verify the locate description matches the excavation project, if not then request additional locates.

- Hand dig within tolerance zone or use other non-invasive methods to expose and determine the exact location of underground facilities before using mechanized equipment.
- If an underground facility is discovered that is not marked, notify the owner/operator, or call 811.
- Properly support and protect the pipeline and other utilities when exposed.
- Maintain the locate markings. Marks are good for the following timeframes starting from the day after notification to 811/One Call Center. If your project will not be completed prior to the expiration of the locate ticket, call 811/One Call Center to update the ticket at least 2 full business days prior to expiration:
  - WA = 45 days, then request new locates
  - ID = Three consecutive weeks (21 days), then request new locates
  - OR = 45 days, then request new locates
- If an excavator damages a utility, then refer to the section on Avista Damage to Other Facility Operators later in this specification.
- If damage occurs to a pipeline and gas is escaping, call 911.

Marking of pipe after installation is a requirement in Oregon per OAR 952-001-0070 (8). In areas of ongoing excavation or construction (such as residential or commercial site development) in Oregon, newly installed facilities shall be located and marked with locate paint or appropriate flagging for backfilled facilities immediately upon placement. For shaded pipe in a ditch where Avista is not backfilling the ditch, locate and mark using locate paint on the sand or “natural gas” caution/warning tape which may be placed on the sand over the pipe using sand in various places to anchor the tape in place so that the location of the pipe is still visible.

Locate Ticket Availability

Avista crews (whether company employees or contractors), should have a copy of the One Call locate ticket on site whenever performing excavation.

On-Site Inspections - General

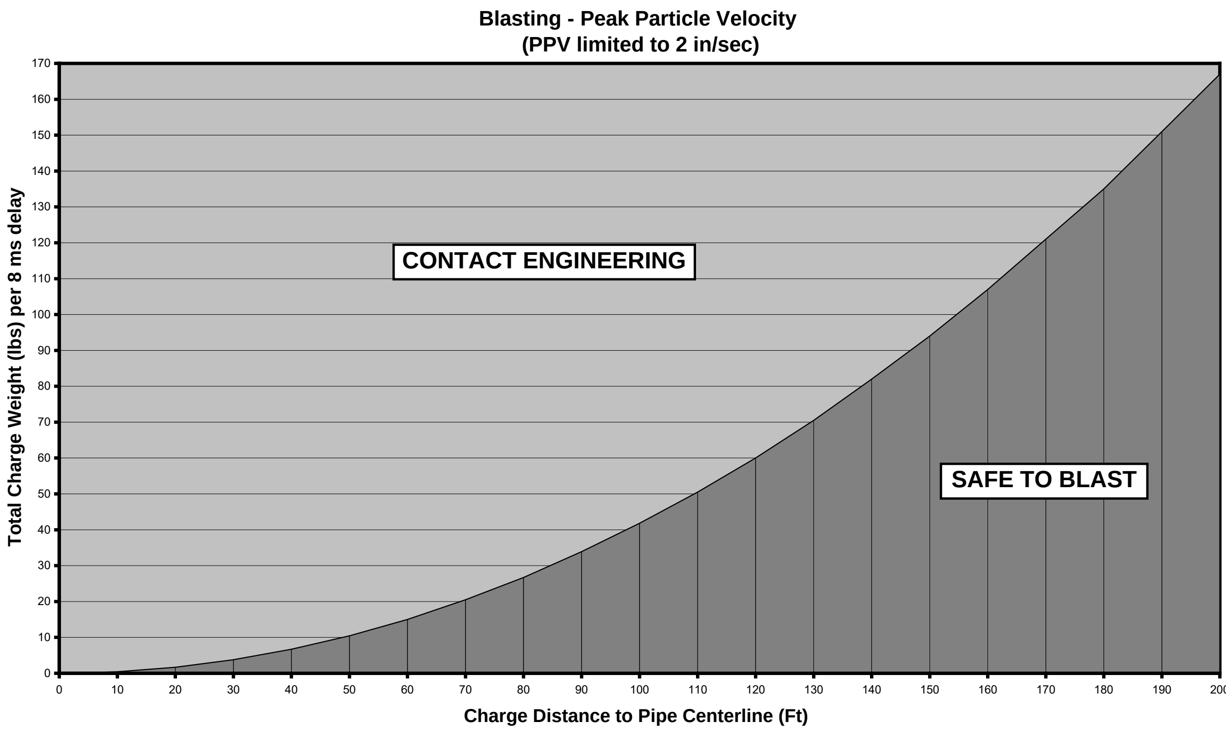
If company personnel are made aware there exists a possibility that company gas pipelines or facilities could be damaged by excavation or construction activities the following procedures shall apply:

- The pipeline or other facilities shall be inspected as frequently as deemed necessary before and after the construction or excavation activities. The employee performing the inspection shall be properly trained to verify that the integrity of the pipeline or other gas facility has not been compromised. Whenever a pipeline is exposed, whether steel or PE, an Exposed Piping Inspection Report form (N-2534) shall be completed. If the pipeline is damaged (including the coating if steel pipe), it shall be repaired per the appropriate company procedure. For steel piping, a pipe-to-soil read shall be taken. Refer to Specification 3.44, Exposed Pipe Evaluation.
- In areas of underground utility congestion, company personnel should consider the advantages of opening bell holes and exposing the various utilities prior to excavation. When a proposed excavation is planned in proximity to any gas line, the line should be located by bell holing at a number of locations necessary to determine the exact location of the pipeline.
- When trenchless methods are used, underground facilities that cross the bore path must be located and protected. Those facilities that cross the bore path must be day-lighted (potholed) to verify location and depth. This applies to those streets with a pavement cut moratorium in place as well; if the location and depth of foreign utilities cannot be positively identified an alternate bore path must be selected. Refer to Specification 3.19, Trenchless Pipe Installation Methods for minimum potholing requirements.
- In the cases of major road, sewer, or construction projects consideration shall be given to appointing an employee dedicated to assuring that company facilities are not damaged.

Blasting Near Pipelines

Blasting activities within 200 feet of any gas facility require evaluation by Avista Gas Engineering. An Avista representative should be on site during the blasting operation. No blasting operation is allowed that will adversely affect Avista facilities.

Following a blast performed within 200 feet of any gas pipeline, or a blast that has the potential to damage a gas facility, a post inspection leak survey shall be completed to verify the integrity of the pipeline system.



For blasting operations in which the predicted Peak Particle Velocity (PPV) of the blast will exceed 2 in/sec at the pipe an engineering evaluation of the blasting operation is required (refer to chart below). PPV is a measure of the ground vibration caused by blasting.

When blasting within 200 feet of a pipeline and the predicted PPV is less than 2 in/sec (Safe to Blast) then the contractor shall provide seismic monitoring at a location perpendicular to the blast and over the pipeline to verify the blaster is operating within the predetermined limits.
Engineering evaluations include review of the contractor submitted blasting plan. The plan shall include the following information:

1.) Date of blast
2.) Drawing specific to the location of the blast including distance to Avista facilities
3.) Hole size, spacing, depth, and layout
4.) Type of explosive and specific energy release
5.) Total weight of explosives
6.) Delay interval
7.) Maximum charge weight/delay

Gas Engineering shall review the blasting plan for conformance with Avista's Gas Standards.

Blasting operations shall restrict the Total Combined Stress on the pipeline to no greater than 80 percent of SMYS for all operating class locations. The total combined stress on the pipeline shall be determined in accordance with AGA Project PR-15-109 "Pipeline Response to Buried Explosive Detonations."

On-Site Inspections for Transmission Facilities

Additional preventative and mitigative measures are required for transmission pipelines that are affected by §192, Subpart O – Pipeline Integrity Management. Avista is required to monitor all excavations near transmission pipelines.

The following procedures shall apply:

- Locating personnel will inform the designated individual, who will be the coordinator in each construction area that has transmission facilities (Spokane, Colville, and Klamath Falls areas), any time they perform a locate on a transmission line. The locating personnel will provide the locate ticket for recordkeeping purposes.
- The designated individual or company representative will do the initial screening by contacting the One Call requestor or contractor to determine where they will be digging and if the location will likely be within 10 feet of a transmission pipeline.
- The coordinator will arrange for an Avista representative (inspector) to be on-site during the excavation work, if it has been determined that digging will be within 10 feet of the transmission line. The Avista representative will indicate on the one call ticket (or on a separate form attached to the one call ticket) their name, the date they completed the stand-by inspection, and whether the pipe was exposed. A copy of the ticket (and form) shall be forwarded to the Damage Prevention Administrator and a copy shall be kept in the local construction office.
- When facilities are exposed, the company representative will document the condition of the coating and pipe on an Exposed Piping Inspection Report form (N-2534) and take a pipe-to-soil read if the coating is compromised.
- If mechanical damage occurs to the pipeline during the excavation, whether it results in a leak or not, data shall be collected in the same format as all other excavation damage (either through the field computer or on a Gas Operating Order form (N-2633). The excavator information must be filled out on the form and mapped in Avista's AFM (GIS) mapping system. When damage occurs, the Damage Prevention Administrator should be notified.
- If blasting is planned near the pipeline, refer to the previous section on Blasting Near Pipelines.

Excavation Identified Without a Locate Ticket (WA Transmission)

If there is evidence that excavation near a transmission pipeline was completed without a locate request or that Avista was not made aware of, notify the Damage Prevention Administrator as a follow-up assessment is required to determine if the pipeline sustained damage.

The Damage Prevention Administrator will in turn notify the Pipeline Integrity Program Manager and Gas Engineering to determine the appropriate method of assessment (response).

When an Avista employee discovers an excavator digging within 35 feet of a transmission pipeline without first obtaining utility locates, the following information shall be acquired at the time of the discovery and provided to the Damage Prevention Administrator:

Acquire the following information:

- Date of Observance
- Company name
- Operator name
- Operator address
- Operator phone number
- Location of dig site/address
- Type of excavator
- Type of work being performed
- Individual who observed the digging

WAC 480-93-200(9) – Each gas pipeline company must report to the commission the details of (a) each instance of the following when the company or its contractor observes or becomes aware of an excavator that digs within 35 feet of a transmission pipeline without first obtaining a locate. (b) A person intentionally damages or removes the marks indicating the location or presence of gas pipeline facilities.

The Damage Prevention Administrator and the Pipeline Safety Engineer should coordinate the notice with the Washington Utilities and Transportation Commission (WUTC) in accordance with the reporting rule and as mentioned previously. The report should be completed within 45 days of discovery. Auditable documentation of the correspondence shall be retained within the commission correspondence files in Gas Engineering.

Intentional Damage or Removal of Locate Marks

When an Avista employee discovers that gas locate marks have been intentionally damaged or removed in the state of Washington, notification to the Washington Utilities and Transportation Commission (WUTC) must be made per WAC 480-93-200(9)(b). The Damage Prevention Administrator and the Pipeline Safety Engineer should coordinate the notice and provide relevant details of the event that were observed or that the company employee became aware of. The report should be completed within 45 days of discovery. Auditable documentation of the correspondence shall be retained within the commission correspondence files in Gas Compliance.

Mapping Corrections

Occasionally, when locating facilities, errors will be noted on Company maps. Mapping errors and corrections shall be completed in accordance with Specification 4.11, Continuing Surveillance.

Response to Facility Damage

Identified ***damage*** to Avista facilities shall be repaired in accordance with Avista Gas Standards. Documentation of damage to Avista's facilities shall be captured through the existing Gas Trouble process as detailed in Section 2 of the GESH – "Leak and Odor Investigation".

Instances of damage to other facility operators shall be captured using the Damage Information Reporting Tool (DIRT) Field Form.

Damage includes the substantial weakening of structural or lateral support of an underground facility, penetration, impairment or destruction of any underground protective coating, housing or other protective device, or the severance (partial or complete) of any underground facility to the extent that the project owner or the affected facility owner or facility operator determines that repairs are required.

Avista Damage to Other Facility Operators

When Avista personnel damage other operator's facilities the damage shall be reported to the Claims Department and documented on the Damage Information Reporting Tool (DIRT) Field Form. Additionally, Avista shall notify the other facility operator so appropriate repairs can be completed.

At a minimum the following information shall be documented on the DIRT form:

- Date and time of the incident
- Avista employee involved in the incident
- Location of the incident (with enough information to be found by another individual)
- Description of the damage
- Locate information
- Whether a one-number locator service was notified before excavation commenced, and, if so, the locate ticket number provided by a One Call locator service
- Root cause of why damage occurred
- Type of Right-of-Way where damage occurred
- Type of underground facility damaged
- Type of excavator that caused the damage
- Type of excavation equipment that caused the damage
- Type of work that was being performed when the damage occurred
- Type of locator (contract or company)
- Did damage cause interruption of service?
- Was the work area pre-marked (showing the boundary of the excavation site)?
- Did this event involve a sewer cross bore?
- Measured depth from grade
- Photographs of the damaged facility

Completed Damage Information Reporting Tool (DIRT) Field Forms shall be sent to the Damage Prevention Administrator at MSC-6, who will review the information and submit the report information into the respective state reporting databases.

- WA damages through the UTC Virtual DIRT database within 45 days of the incident as required by RCW 19.122.053.
- ID damages through the Damage Prevention Board Virtual DIRT database as required by Idaho Code Chapter 22, Section 55-2208 (5)
- OR damages through CGA DIRT

Refer to Avista Specification 4.14, Recurring Reporting Requirements. Avista excavators and their contractors are required to call the local public safety agency (i.e., 911) when excavation damage they have caused, results in an emergency condition. The following calls must also be made:

Washington:	Operator of the facility that was hit and 811 One Call Center
Oregon:	Operator of the facility that was hit
Idaho:	Owner of the facility that was hit and 811 One Call Center

Photograph Requirements

Photographs shall be taken of excavation damages and should include sufficient detail to represent information related to the excavation damage. Details should include but are not limited to:

- Photographs of the damage, in-line with the damaged utility, including permanent background objects or structures and the surrounding area from all four directions
- Locate marks or photograph representing lack of locate marks
- Excavation location
- Use of measurement devices such as a tape measure to convey dimensions, including locates outside the tolerance zone*.
- Use of a note within the photograph to convey the following:
    - Date of damage event
    - Location
    - Work Order or Service Request Number or claim number when available.

Photographs shall be emailed to photos@avistacorp.com to assist with the determination of the root cause, filing of excavator complaints, and for claims processing.

WA Damage Reporting

Damaged facilities in Washington shall be reported in accordance with Specification 4.14, Recurring Reporting Requirements.

WAC 480-93-200(7)(b) - If the damage is believed by the company to be the result of an excavation conducted without a facilities locate first being completed, the gas pipeline company must also report the name, address, and phone number of the person or entity that the company has reason to believe may have caused the damage. The company must include this information in the comment section of the web-based damage reporting tool form or sent to the commission separately. If the company chooses to send the information separately, it must include sufficient information to allow the commission to link the name of the party believed to have caused the damage with the damage event reported through the damage reporting tool.

WAC 480-93-200(7)(c) - Each gas pipeline company must retain all damage and damage claim records it creates related to damage events, including photographs and documentation supporting the conclusion that a facilities locate was not completed, reported under subsection (b) of this section, for a period of two years and make those records available to the commission upon request.

WA Excavator Notifications

For damage to gas facilities located in Washington, Avista shall provide to the excavator the information as required by WAC 480-93-200(8).

> **WAC 480-93-200(8)** Each gas pipeline company must provide, to an excavator who damages a gas pipeline facility, the following information set forth in chapter 19.122 RCW;
>
> (a) Notification requirements for excavators under RCW 19.122.050(1);
>
> (b) A description of the excavator's responsibilities for reporting damages under RCW 19.122.053; and
>
> (c) Information concerning the safety committee referenced under RCW 19.122.130, including committee contact information, and the process for filing a complaint with the safety committee.

Building Permits near Transmission Utility Easements or Rights of Way

When Avista is contacted by third parties regarding pipeline facilities, the following minimum information shall be conveyed. In Washington, permitted construction activity within 100 feet of a transmission line will require the building applicant to consult with Avista. Consultation related to transmission facilities should be conducted by the Pipeline Integrity Program Manager. The Pipeline Integrity Program Manager shall document information about the consultation and file that document with the IMP program documents. The following minimum information shall be conveyed to the applicant:

- Location of pipeline facilities
- Possible future notification information
- Damage prevention requirements including 811 information
- Vegetation management requirements
- Pipeline accessibility information
- Easements, if applicable

> **RCW Chapter 19.122.033(4)** Any unit of local government that issues permits under codes adopted pursuant to chapter 19.27 RCW must, when permitting construction or excavation within one hundred feet, or greater distance if required by local ordinance, of a right-of-way or utility easement containing a transmission pipeline: (a) Notify the pipeline company of the permitted activity when it issues the permit; or (b) Require, as a condition of issuing the permit, that the applicant consult with the pipeline company.

4.14 RECURRING REPORTING REQUIREMENTS

SCOPE:

To establish procedures for the submission of federal and state reports.

REGULATORY REQUIREMENTS:

§191.7, §191.11, §191.12, §191.13, §191.15, §191.17, §191.22, §191.29, §192.945

RCW 19.122.053, 81.88.080, 81.88.160

Idaho Code §55-2208 (5)

WAC 480-93-180, 480-93-200

CORRESPONDING STANDARDS:

Spec. 4.13, Damage Prevention

General

There are annual and conditional reporting requirements by PHMSA and state commissions. This specification covers these requirements.

Reporting Distribution Facilities

Information for Avista's distribution systems shall be reported on form PHMSA F7100.1-1. A separate form must be filled out and filed for each state in which the system operates.

Reporting Transmission Facilities

Information for Avista's transmission facilities shall be reported on form PHMSA F7100.2-1. Only one form submission is required as it encompasses all states within the one form.

Submission of Reports

Avista, as an intrastate pipeline operator, shall submit federal annual reports via PHMSA's online reporting tool at their website no later than March 15 of each calendar year.

In the event the website is unavailable or inoperable, reports can be submitted via hardcopy to the following address:

Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
US Department of Transportation
Information Resources Manager, PHP-20
1200 New Jersey Avenue SE.
Washington, DC 20590-0001

A copy of Form F7100.1-1 and/or F7100.2-1 shall also be submitted to each respective state commission no later than March 15 of each calendar year.

TIMP Performance Reporting

In accordance with §192.945 operators with transmission facilities that fall under Subpart O – Pipeline Integrity Management is required to submit on an annual basis a report on the TIMP Performance Measures. These reports are submitted as part of the Transmission Annual Report, as mentioned above.

PHMSA Conditional Reporting

The following conditional reports shall be made to PHMSA as applicable and within the specified timeframes as shown and as discussed at §191.22.

1. Construction of or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe that costs $10 million or more. (60 days before the event occurs. If 60-day notice is not feasible due to an emergency, notification must be as soon as practicable).
2. Construction of 10 or more miles of a new or replacement pipeline (60 days before the event occurs).
3. Construction of a new LNG plant or LNG facility (60 days before the event occurs).

Note: The definition of "construction" in the previous paragraphs was amplified in Advisory Bulletin ADB-2014-03 to include Material Purchasing/manufacturing; Right-of-Way Acquisition; Construction equipment move-in; on-site/off-site fabrications and right-of-way clearing, grading, and ditching.

4. A change in the primary entity responsible for managing or administering a safety program required by federal code covering pipeline facilities operated under multiple Operator Identification Numbers (OPIDs) (Within 60 days after the event occurring).
5. A change in the name of the operator (Within 60 days after the event occurring).
6. A change in the entity responsible for an existing pipeline, pipeline, pipeline segment, pipeline facility or LNG facility (Within 60 days after the event occurring).
7. The purchase or sale of 50 or more miles of pipeline or pipeline system (Within 60 days after the event occurring).
8. The purchase or sale of an existing LNG plant or facility (Within 60 days after the event occurring).

WUTC Pipeline Leaks Emissions Report

RCW 81.88.160: In the state of Washington, on an annual basis, each gas pipeline company must submit a report to the commission that includes total number of known leaks for the calendar year detailing if the leak was hazardous/non-hazardous, repaired/scheduled for repair, volume of gas loss, CO_2 equivalent emissions, market value of gas loss, location and date of each leak, and the failure cause of each leak. The report is due no later than March 15 of the calendar year.

WUTC Construction Defects and Material Failures Report

WAC 480-93-200(10)(b): In the state of Washington, a report detailing all construction defects and material failures resulting in leakage must be submitted to the Washington Utilities and Transportation Commission no later than March 15 of each year, to include information from the preceding year.

DOT Drug and Alcohol MIS Form Submission

WAC 480-93-200(13): In the state of Washington, when a gas pipeline company is required to file a copy of a DOT Drug and Alcohol Testing Management Information System (MIS) form with US DOT, Office of Pipeline Safety, the gas pipeline company must simultaneously submit a copy of the form to the commission. The report is due no later than March 15 of the calendar year.

Plans and Procedures

WAC 480-93-180(2): Plans and Procedures – The manual must be filed with the commission forty-five days prior to the operation of any gas pipeline. Each gas pipeline company must file revisions to the manual with the commission annually. The commission may, after notice and opportunity for hearing, require that a manual be revised or amended. Applicable portions of the manual related to a procedure being performed on the pipeline must be retained on-site where the activity is being performed.

A copy of the updated Gas Standards Manual and the Gas Emergency and Service Handbook shall be filed annually with the Washington Utilities and Transportation Commission (WUTC). The submission should be completed near the first of the year following standards revisions and shall be submitted electronically. Copies of the updated documents shall also be submitted to the Idaho Public Utilities Commission and the Oregon Public Utilities Commission. Hardcopy or electronic is acceptable to these entities.

NPMS Updating

In accordance with §191.29***,*** Avista shall provide the following geospatial data to PHMSA:

- Geospatial data, attributes, metadata, and transmittal letter appropriate for use in the National Pipeline Mapping System (NPMS).
- The name and address for the operator (Avista).
- The name and contact information of a pipeline company employee to be displayed on a public Web site, who will serve as a contact for questions from the general public about the operator's NPMS data.

The information required above must be submitted each year, on or before March 15, representing assets as of December 31 of the previous year. If no changes have occurred since the previous year's submission, Avista must comply with the guidance provided in the NPMS Operator Standards manual available at http://www.npms.phmsa.gov or by contacting the PHMSA GIS Manager at 202-366-4595.

250+ PSIG Pipelines Map Submission (Washington)

In accordance with RCW 81.88.080***,*** Avista shall provide accurate maps of pipelines that operate above 250 psig to the commission. It shall be the responsibility of the Gas Integrity Management Analyst to ensure an updated cache of all such maps are electronically forwarded to the commission annually no later than March 15.

WA Damage Reporting

In accordance with the Washington RCW and UTC reporting requirements regarding the reporting of damages to underground facilities, Avista shall report the following within 45 days of the damage event using the Washington commission's virtual private damage information reporting tool (DIRT) report form or other similar form.

RCW Chapter 19.122.053(1) & (3) Facility operators and excavators who observe or cause damage to an underground facility must report the damage event to the commission within forty-five days of the damage event using DIRT.

RCW CHAPTER 19.122.053(2) A non-pipeline facility operator conducting an excavation, or a subcontractor conducting an excavation on the facility operator's behalf, that strikes the facility operator's own underground facility is not required to report that damage event to the commission.

Avista shall report all known instances of damage to Avista's gas facilities by others and by Avista employees. Additionally, the report shall include instances of damage events to other facility operators by Avista. Instances of damage shall be captured as detailed within Specification 4.13 – Damage Prevention.

WAC 480-93-200(7) In the event of damage to a gas pipeline, each gas pipeline company must provide to the commission the following information using either the commission's web-based damage reporting tool or its successor, or the damage reporting form located on the commission's website: (a)The reporting requirements set forth in RCW 19.122.053(3)(a) through (n).

WA Reporting Requirements

The following elements shall be reported in accordance with WAC 480-93-200(7) and as set forth in RCW 19.122.053(3)(a) through (n):

- The name of the person submitting the report and whether the person is an excavator, a representative of a one-number locator service or a facility operator.
- The date and time of the damage event.
- The address where the damage event occurred.
- The type of right-of-way, where the damage event occurred, including but not limited to city, street, state highway, or utility easement.
- The type of underground facility damaged, including but not limited to pipes, transmission pipelines, distribution lines, sewers, conduits, cables, valves, lines, wires, manholes, attachments, or parts of poles or anchors below ground.
- The type of utility service or commodity the underground facility stores or conveys, including but not limited to electronic, telephonic, or telegraphic communications, water, sewage, cablevision, electric energy, petroleum products, gas, gaseous vapors, hazardous liquids, or other substances.
- The type of excavator involved, including but not limited to contractors or facility operators.
- The excavation equipment used, including but not limited to augers, bulldozers, backhoes, or hand tools.
- The type of excavation being performed, including but not limited to drainage, grading, or landscaping.
- Whether a one-number locator service was notified before excavation commenced, and, if so, the excavation confirmation code provided by a one-number locator service.
- Whether an excavator experienced interruption of work as a result of the damage event.
- A description of the damage.
- Whether the damage caused an interruption of underground facility service.

For instances in which Avista believes the facility damage was the result of an excavation without a facilities locate the following additional information shall be reported.

- **<u>If applicable</u>:**
    - o The person who located the underground facility and their employer.
    - o Whether underground facility marks were visible in the proposed excavation area before excavation commenced.
    - o Whether underground facilities were marked correctly.

WAC 480-93-200(7)(b) - If the damage is believed by the company to be the result of an excavation conducted without a facilities locate first being completed, the gas pipeline company must also report the name, address, and phone number of the person or entity that the company has reason to believe may have caused the damage. The company must include this information in the comment section of the web-based damage reporting tool form or sent to the commission separately. If the company chooses to send the information separately, it must include sufficient information to allow the commission to link the name of the party believed to have caused the damage with the damage event reported through the damage reporting tool.

ID Damage Reporting

In accordance with the Idaho Code reporting requirements regarding reporting of damages to underground facilities, Avista shall report each damage event by no later than March 31 for the previous year's damages. Damage events shall be reported using the Idaho Damage Prevention Board's virtual private damage information reporting tool (DIRT) database.

Idaho Code Title 55 Chapter 22; 55-2208 (5) Underground facility owners and excavators who observe, suffer or cause damage to an underground facility or observe, suffer, or cause excavator downtime related to a failure of one (1) or more stakeholders to comply with applicable damage prevention regulations shall report such information to the board in accordance with the rules promulgated by the board.

Document Retention

Records related to damage events are auditable for 2 years under the WAC reporting requirements. Document retention is greater than 2 years for information related to the DIMP or other code requirements. Refer to applicable standards. Supporting documentation could include but is not limited to:

- Trouble Order Information (1st Responder Operating Order).
- Service work order contained within Maximo.
- Exposed Piping Inspection Reports.
- Photographs.
- Avista Claims documentation and investigation documents.

WAC 480-93-200(7)(c) Each gas pipeline company must retain all damage and damage claim records it creates related to damage events, including photographs and documentation supporting the conclusion that a facilities locate was not completed, reported under subsection (b) of this section, for a period of two years and make those records available to the commission upon request.

4.15 MAXIMUM ALLOWABLE OPERATING PRESSURE (MAOP)

SCOPE:

To define and explain Maximum Allowable Operating Pressure (MAOP) as it is addressed in the applicable regulatory codes and as it applies to Avista's operations.

REGULATORY REQUIREMENTS:

§192.5, §192.14, §192.105, §192.195, §192.605, §192.607, §192.619, §192.620, §192.621, §192.623, §192.624

WAC 480-93-018, 480-93-020, 480-93-155, 480-93-180, 480-93-200

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design - Steel
Spec. 2.13, Pipe Design - Plastic
Spec. 2.23, Regulator Design
Spec. 4.17, Uprating

General

It is desirable to operate the gas systems near the documented MAOP. This provides for maximum system capacity during periods of unusually cold weather or other high system demand.

The majority of Avista's intermediate pressure distribution systems have an MAOP of 60 psig, although some systems have a lower MAOP. The intermediate pressure systems are most susceptible to pressure loss during periods of high demand and for this reason should be operated near the system MAOP.

Determination of MAOP

The determination of the MAOP of any gas pipeline segment is made by Gas Engineering. The MAOP is based on one or several of the following factors (with the lowest pressure being the established MAOP for the system or segment):

- The design pressure of the weakest part of the pipeline segment as calculated by §192.105. For steel pipe in pipelines being converted under §192.14 or uprated, if any variable necessary to determine the design pressure under the design formula in §192.105 is unknown, one of the following pressures is to be used as design pressure:
    - 80 percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factor in §192.619 (a)(2)(ii) or if the pipe is 12.75 inches or less in outside diameter and is not tested to yield the design pressure would be 200 psig.
- The MAOP established at the time of the pressure test by dividing the pressure to which the segment was tested after construction as follows:
    - For plastic pipe in all locations, the test pressure is divided by a factor of 1.5
    - For steel pipe operated at 100 psig or more, the test pressure is divided by a factor determined in accordance with the following table:

Factors				
Class Location	Installed before 11/12/1970	Installed after 11/11/1970 and before 7/1/2020	Installed on or after 7/1/2020	Converted under §192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

- The pipeline is operating in satisfactory condition and the highest actual operating pressure the segment was subjected to during the five years preceding July 1, 1970. This restriction applies unless the segment was pressure tested in accordance with §192.619 after July 1, 1965.
- The pressure that is determined to be the maximum safe pressure after considering and accounting for records of material properties, including material properties verified in accordance with §192.607, if applicable, and the history of the segment, including known corrosion and the actual operating pressure. However, overpressure protection must be installed on the segment in a manner that will prevent the MAOP from being exceeded in accordance with §192.195.

WAC 480-93-020: In Washington State, there are limitations to MAOP's due to proximity to buildings intended for human occupancy. Refer to Specification 2.12, Pipe Design - Steel.

Changing MAOP

The MAOP of a pipeline or system shall not be exceeded unless the particular facility has been uprated according to the procedures outlined in Specification 4.17, Uprating. The MAOP of a pipeline may be reduced based on several factors such as damage, corrosion, or operating characteristics of the pipeline as determined by Gas Engineering.

MAOP Consideration during Startup and Shutdown

The various aspects of bringing a pipeline into or out of service are addressed in Specification 3.17 (Purging Pipelines), 3.18 (Pressure Testing), 5.16 (Abandonment or Inactivation of Facilities), 5.17 (Reinstating Abandoned Gas Pipelines and Facilities), and elsewhere in Avista's Gas Standards. In all instances of bringing pipelines into service or shutting them down, the MAOP of these systems must not be exceeded. In the event the MAOP is exceeded, contact the Gas Engineering Manager and the Pipeline Safety Engineer. Downstream system investigations may likely be warranted, and state and/or Federal notifications may be necessary.

Recordkeeping

Records for transmission pipeline segments operating in a Class 3, Class 4, or High Consequence Area shall be Traceable, Verifiable and Complete per §192.624. If records for these pipeline segments are not Traceable, Verifiable and Complete, or if the MAOP for these segments is greater than 30% of the Specified Minimum Yield Strength (SMYS) and was established using the Grandfather Clause [§192.619(c)], they would be subject to MAOP Reconfirmation in accordance with the Transmission Integrity Management Program (TIMP) documentation. Records for any MAOP reconfirmation or materials verification shall be retained for the life of the pipeline. All records that could be used to establish MAOP for transmission pipeline segments in operation as of July 1, 2020 shall be retained for the life of the pipeline. Likewise, any records that could be used to establish MAOP for high pressure distribution and intermediate pressure distribution should be retained for the life of the pipeline as well.

Any newly installed or repaired segments of transmission pipeline must make and retain Traceable, Verifiable and Complete records for the establishment of the MAOP for the life of the pipeline. The same requirement should apply to all newly installed high-pressure distribution segments placed in operation. Records pertaining to transmission and high-pressure distribution MAOP shall be centralized and kept in

Avista's Spokane Gas Engineering office for all service territories. Records for intermediate pressure MAOP are held locally in the construction office. The MAOP of all pipelines, valves, and fittings in Avista's system is maintained in Avista's AFM (GIS) system and it is the responsibility of Gas Engineering and GIS Edit teams to update and maintain as necessary.

WAC 480-93-018 (5): Each gas pipeline company must update its records within 6 months of when it completes any construction activity and make such records available to appropriate company operations personnel.

4.16 CLASS LOCATIONS

SCOPE:

To assist in determining the design criteria, construction practices, and maintenance frequencies of Avista's gas facilities as they relate to the applicable Federal and State codes.

REGULATORY REQUIREMENTS:

§192.5, §192.179, §192.609, §192.610, §192.611, §192.613, §192.619, §192.620, §192.636

WAC 480-93-020, 480-93-155

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design – Steel
Spec. 2.14, Valve Design
Spec. 3.12, Pipe Installation – Steel Mains
Spec. 3.18, Pressure Testing
Spec. 4.15, Maximum Allowable Operating Pressure (MAOP)
Spec. 4.17, Uprating
Spec. 5.11, Leak Survey
Spec. 5.15, Pipeline Patrolling and Pipeline Markers

General

For Avista, determinations of class locations and the subsequent monitoring of those locations applies to pipelines which operate at a hoop stress equal to or greater than 20 percent SMYS for the purposes of patrolling (refer to Specification 5.15, Pipeline Patrolling and Pipeline Markers).

A class location unit along a pipeline extends 220 yards on each side of the centerline of any contiguous one-mile length of pipe.

Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

Class Locations

Class 1 location is any class location unit that has **10 or fewer** buildings intended for human occupancy.
Class 2 location is any class location unit that has **more than 10, but fewer than 46** buildings intended for human occupancy.
Class 3 location is:

- Any class location unit that has **46 or more** buildings intended for human occupancy; or
- An area where the pipeline lies within 100 yards of either a building that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive); or
- An area where the pipeline lies within 100 yards of a small, well defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly), that is occupied by at least 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

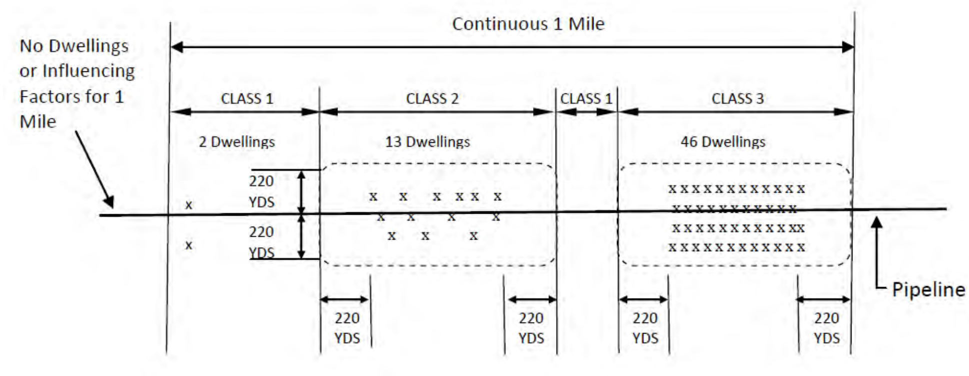
Class 4 location is any class location unit where **buildings with 4 or more stories** aboveground are prevalent.

Class Location Boundaries

The boundaries of the above-mentioned class locations may be adjusted in accordance with the following:

- A Class 4 location ends 220 yards from the nearest building with 4 or more stories aboveground.
- In a Class 3 location when there is a cluster of buildings intended for human occupancy that ends 220 yards from the nearest building in the cluster.
- In a Class 2 location when there is a cluster of buildings intended for human occupancy that ends 220 yards from the nearest building in the cluster.

EXAMPLE OF CLUSTERING



Class Location Study

Determining the boundaries of class location areas is essential for implementation of Avista's maintenance and operational programs as required by State and Federal regulations.

A review of the class locations should be done annually for pipeline segments that operate greater than 20 percent SMYS as part of the preparation for the submission of the PHMSA Report F7100.2-1 Annual Report for Natural or Other Gas Transmission and Gathering Systems. This information shall be provided to Gas Engineering for confirmation or revision of MAOP's as outlined below in this specification.

Change in Class Location

When an increase in population density indicates a change in class location for a segment of an existing steel pipeline operating at a hoop stress that is greater than 40 percent SMYS or indicates that the hoop stress corresponding to the established maximum allowable operating pressure (MAOP) for a segment of existing pipeline is not commensurate with the present class location; a study shall be done immediately per the requirements of §192.609 to determine:

1) The present class location for the segment involved.
2) The design, construction, and testing procedures followed in the original construction and a comparison of these procedures with those required for the present class location.
3) The physical condition of the segment to the extent it can be ascertained from available records.
4) The operating and maintenance history of the segment.
5) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved.
6) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.

If a change in class location occurs after September 27, 2022, and results in pipe replacement of 2 or more miles, in the aggregate, within any 5 contiguous miles within a 24-month period, to meet the MAOP requirements in §192.611, §192.619 or §192.620, then the requirements for Rupture Mitigation Valves (RMVs) in Specification 2.14 (Valve Design) apply to the new class location and RMVs shall be installed to meet all applicable requirements.

If a change in class location occurs after September 27, 2022, and results in pipe replacement of less than 2 miles within 5 contiguous miles during a 24-month period, to meet the MAOP requirements in §192.611, §192.619 or §192.620, then within 24 months of the class location change, in accordance with §192.611(d), the following requirements apply (with the exception of replacements of less than 1,000 feet within 1 contiguous mile):

1) Comply with the valve spacing requirements of §192.179(a) for the replaced pipeline segment; or

2) Install or use existing RMVs or alternative equivalent technologies so that the entirety of the replaced pipeline segments are between at least two RMVs or alternative equivalent technologies. The distance between RMVs or alternative equivalent technologies for the replaced segment must not exceed 20 miles, and the RMVs or alternative equivalent technologies must comply with the applicable requirements of §192.636.

Confirmation or Revision of MAOP

Confirmation or revision of the maximum allowable operating pressure (MAOP) that is required as a result of a study as outlined above must be completed within 24 months of the change in class locations as outlined below per the requirements of §192.611. Pressure reduction under paragraph (1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (3) of this section at a later date.

If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to <u>one</u> of the following requirements:

1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

   a) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

   b) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per § 192.620, the corresponding hoop stress may not exceed 80 percent of SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

2) The MAOP of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

3) The segment involved must be tested in accordance with the applicable requirements of Part 192 Subpart J and its MAOP must then be established according to the following criteria:

   a) The MAOP after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

   b) The corresponding hoop stress may not exceed 72 percent of SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

   c) For a pipeline operating at an alternative maximum allowable operating pressure per § 192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

The MAOP confirmed or revised in accordance with this section, may not exceed the MAOP established <u>before</u> the confirmation or revision.

Confirmation or revision of the MAOP of a segment of pipeline in accordance with this section does not preclude the application of the general requirements of Uprating in §192.553 and §192.555 – Uprating to a pressure equal to or greater than 30 percent of SMYS.

MAOP Reconfirmation

Transmission pipeline segments operating in a Class 3 or 4 location, or in a High Consequence Area (HCA) must have records necessary to establish the MAOP per 192.619(a), including requirements of 192.517(a) that are Traceable, Verifiable and Complete (TVC). If TVC records are not available, the MAOP Reconfirmation procedure set out in the Transmission Integrity Management Program (TIMP) document shall be followed.

For pipelines with MAOP established per 192.619(c), also known as the “grandfather clause”, the MAOP shall be reconfirmed per the TIMP document if the pipe segment operates at greater than or equal to 30 percent SMYS and is in a Class 3, Class 4, or HCA location.

Documentation of MAOP Revisions

Changes identified through the class location study and the MAOP confirmation or revision review shall be documented and retained for the life of the asset.

Records

Records shall document the current class location of each transmission pipeline segment and how each class location was determined. This will be kept with the document for Transmission Integrity Management Program (TIMP) and maintained according to that document’s retention policy.

4.17 UPRATING

SCOPE:

To establish procedures to be followed when increasing the maximum allowable operating pressure(s) of Avista gas distribution and transmission pipeline facilities.

REGULATORY REQUIREMENTS:

§192.503, §192.551, §192.553, §192.555, §192.557, §192.619

WAC 480-93-020, 480-93-155, 480-93-160

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design - Steel
Spec. 2.13, Pipe Design – Plastic (Polyethylene)
Spec. 3.18, Pressure Testing
Spec. 4.15, Maximum Allowable Operating Pressure (MAOP)
Spec. 5.11, Leak Survey

General

Determinations relating to the raising of MAOP of a pipeline shall be made by Gas Engineering in coordination with the local construction office. Uprating procedures in the field shall be performed by properly trained and qualified personnel.

An uprate shall be conducted only after the system has been assessed for integrity impacts. This assessment will be conducted by both the assigned Gas Engineer and the Pipeline Integrity Program Manager as part of the historical records review to determine if the pipelines should be uprated. This may include a risk analysis.

When it is determined that it is necessary to raise the MAOP of a pipeline via an uprate, the general procedures outlined in this Specification shall be used:

Uprating Requirements

Review of Design, Operation and Maintenance History – The history of the segment to be uprated shall be reviewed to include materials of construction and pressure ratings of valves and fittings used, cathodic protection history, and history of exposed pipe reports including external and internal inspections of the pipes performed in the past. The review shall include a listing of pipe footage to be uprated by size, material, and installation year.

Previous leak survey results should be considered to ensure there is no indication the segments being uprated are prone to leaks. Previous pressure tests should be collected for mains and services and included in the uprate file. If there are segments of plastic pipe included in the uprate, which do not have pressure test records showing a pressure test of 1.5X the intended MAOP after the uprate, then the uprate shall be conducted to 1.5X the intended final MAOP.

The review shall also include a listing of all meter sets within the uprate area and an analysis of the adequacy of regulator used for pressure rating, as well as relief capacity at the highest pressure the regulator will be subjected to during the uprate.

Written Plan - A written plan shall be developed by Gas Engineering that details the procedures to be followed before, during, and after the uprating process. Gas Engineering shall review the design, operating, and maintenance history of the pipeline segment to assure that the pipeline can be operated safely at the new MAOP, and that regulatory requirements are satisfied. A written plan shall schedule the uprate procedure to assure that once the uprate procedure is started, it is completed in as short a time as practicable, taking into account weather conditions, need for delay to make system repairs, etc.

Incremental Pressure Increases - Increases in operating pressure that are made in increments under the uprating plan shall be performed gradually and at a rate that can be safely controlled.

Leak Survey - The pipeline segment shall be leak surveyed prior to the uprating procedure if it has been more than one year since the last leak survey. At the end of each incremental increase, the pressure shall be held constant while the entire pipeline segment is again checked for leaks. A final leak survey shall be done at the conclusion of the uprating process.

Repairs - Each leak detected must be repaired before a further pressure increase is made. (Exception: a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous). Other repairs necessary to ensure the safe operation of the pipeline segment shall be completed prior to any pressure increases.

Limitation - Except as provided for elsewhere in this standard, a new MAOP established under these procedures shall not exceed the maximum pressure that would be allowed for a new segment of pipeline constructed of the same materials in the same location.

Uprating Pipeline to Hoop Stress <30 Percent SMYS

Before increasing the operating pressure above the previously established MAOP, the above-mentioned general procedures shall be adhered to with the following additions: Repairs, alterations, and replacements in the pipeline segment, that are necessary for safe operation at the increased pressure, shall be performed before increasing operating pressure. This includes replacing reinforcing or anchoring offsets, bends, and end caps in pipe joined by compression couplings to prevent failure of the pipe joint if the offset, bend, or end cap is exposed in an excavation. Service replacements or insertions, as well as relocations of meter sets, shall also be completed prior to increasing pressure.

The segment of pipeline to be uprated should be physically separated (except through a regulator with overpressure protection or valve) from any adjacent segment that will continue to be operated at a lower pressure. The segment being uprated shall have pressure gauges installed (or chart recorders) and shall be monitored before, during, and after each incremental pressure increase. In addition, any adjacent pipeline system or segment that will continue to be operated at a lower pressure than the segment being uprated shall be monitored with pressure gauges (or pressure recording devices) before, during, and after the uprating process to ensure that overpressuring does not occur due to unknown pipe connections.

Increases in the MAOP shall be made in increments that are equal to 10 psig or 25 percent of the total pressure increase (whichever produces the fewest number of increments).

Uprating Pipeline to Hoop Stress ≥30 Percent SMYS

Consult Gas Engineering before considering an uprate that would produce a hoop stress of 30 percent SMYS or higher. If the uprate moves forward, §192.555 must be followed.

Considerations for Uprating Steel Pipelines

When uprating steel gas pipelines, the design pressure of the weakest element shall be determined in accordance with 192.105.

If any of the variables necessary to determine the design pressure are unknown, one of the following pressures is to be used as the design pressure:

- Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8, reduced by the appropriate factor in 192.619(a)(2)(ii)
- If the pipe is 12 ¾" or less in outside diameter and is not tested to yield, the design pressure shall be 200 psig.

Uprate in the State of Washington

<u>Washington Administrative Code (WAC 480-93-155) requires the following reporting procedures in addition to the above stated uprating procedures</u>:

When increasing the MAOP of any pipeline or facility to a pressure over 60 psig, the Commission shall be provided with a written plan and drawings at least 45 days prior to raising the pressure.

The plan shall include a review of the following:

- All affected gas facilities, including pipe, fittings, valves, and other associated equipment along with their manufactured design operating pressure, their specified minimum yield strength (SMYS) at the intended MAOP and any other applicable specifications or limitations.
- Original design and construction standards.
- Original pressure test records.
- Previous operating pressures, identifying the dates and lengths of time at that pressure.
- All leaks, regardless of cause, on the segment and the date and method of repair.
- Where the pipeline is being uprated to an MAOP of over 20 percent of the SMYS, records of the original welding standards and welders.
- Maintenance records for all affected regulators and relief valves for the past 3 years or three most recent inspections, whichever is longer.
- Where applicable, relief valve capacities compared to regulator flow capacities, with calculations.
- Cathodic protection readings of the affected pipeline and facilities, including rectifier readings, for the past 3 years or three most recent inspections, whichever is longer.
- Any additional records that commission staff may deem necessary to evaluate the pressure increase.

<u>Washington Administrative Code requires certain proximity considerations, which must be addressed when planning to uprate above 250 psig</u>. Refer to Specification 2.12, Pipe Design – Steel, "WA State Proximity Considerations" for more information.

<u>UPRATING PROCEDURE - TYPICAL SEQUENCE OF EVENTS:</u>

Prior to Pressure Increase

- An integrity impact review is completed by Gas Engineering and the Pipeline Integrity Program Manager which includes a review of the design, operating and maintenance history of the pipelines to be uprated.
- The first page of the Written Plan for Pressure Uprating (N-2757) document shall be filled out as completely as possible by the Gas Engineer. Include any addendum showing calculations on regulators and relief valves, mechanical fittings in the system, pressure design ratings of valves and other components, changes to odorization system, etc.

- A review of the uprate plan is conducted with key stakeholders including appropriate Gas Control Room personnel.
- A map or drawing is prepared showing the segment to be uprated, along with any lateral connections. Pipeline sizes should be shown as well as the physical location of valves, regulator stations, mechanical fittings, stubs, services to be replaced, meters to be re-located, system isolation points, MAOP's of adjacent systems, and preferred locations of pressure gauges.
- A leak survey is completed on the entire segment and related facilities operating at the current MAOP and results are documented in the Leak Survey Map Viewer or paper maps for a special survey.
- Hazardous leaks are repaired. Grade 2 and 3 leaks are addressed as outlined in Specification 5.11, Leak Survey. All other replacements, repairs, alterations, etc. are completed. Information is recorded on the Written Plan for Pressure Uprating (N-2757) document or on separate work orders and retained in the uprate file.
- Pressure monitoring gauges or recorders are installed, and pressures noted (normally done on the day of the uprate, unless otherwise required.) Pressure gauges should be installed on adjacent systems of lower pressures to avoid overpressuring.

During the Pressure Increases

- Field employees monitor pressure gauges or recorders as segment pressure is gradually increased to the first increment.
- A leak survey is again conducted while the increased pressure is held constant at the first increment. If hazardous leakage is discovered or if the pressure does not stabilize, the pressure should be lowered, and the necessary repairs completed. Repairs should be documented on the Written Plan for Pressure Uprating (N-2757) document or on a separate work order and retained in the uprate file.
- District regulator stations should be checked to verify the integrity of the regulators by checking the downstream pressures.
- When a subsequent leak survey indicates no hazardous leakage, the segment pressure may then be increased to the next incremental step. Continue to follow the above procedures until the final MAOP is safely achieved at the last pressure that establishes it (typically 1.5 times MAOP).
- Document all work and other information on the Written Plan for Pressure Uprating (N-2757) document.
- A final leak survey at this highest pressure is performed and hazardous leaks are repaired. Grade 2 and 3 leaks are addressed as outlined in Specification 5.11, Leak Survey.
- Each time the pressure of the system is to be increased or decreased, Pressure Controlmen must contact the Gas Control Room (509-495-4859 or via radio) to inform them of the change.

Uprate Acceptability Criteria

A final review of all uprate information should be performed before the new MAOP is approved. Final approval is needed by the Gas Engineering Manager and the Pipeline Integrity Program Manager. Examples of information to be reviewed include:

- Leak data and trending – Were the number of underground leaks trending up or down?
- Material reports – Did the Exposed Piping Inspection Reports indicate any material issues?
- Processes followed – Were the processes for the uprate followed correctly? Were any critical steps missed or not performed adequately?

If it is deemed that the uprate project has not met this final acceptability criteria, the system will be returned to a pressure below this MAOP that is deemed safe and acceptable per this requirement which may require returning to the original MAOP.

Following acceptance of the uprate, the first page of the Written Plan for Pressure Uprate (N-2757) document should be stamped by a Professional Engineer as certification of the new MAOP and the uprate package containing all pertinent information shall be retained for the life of the pipeline.

Consideration should be given when needed to perform additional safety measures and may include:

- Performing additional leak surveys after the final MAOP is achieved.
- Pipe or other facility replacements
- Pressure checks at meter sets
- Supplemental risk modeling

After Final MAOP is Achieved

If the project has been deemed acceptable, then:

- The new MAOP is declared, and the system is set back to its final operating pressure.
- Pressure gauges or recording devices are removed (unless required to remain in place).
- Records are noted as to the new MAOP, including the regulator station maintenance records.

Gas Engineering shall make a final review of the segment uprating file to ensure compliance with regulatory codes and Avista standards and retain this record for the life of the pipeline segment.

Recordkeeping

Data pertaining to the uprating procedure for each pipeline segment shall be recorded on the Written Plan for Pressure Uprating (N-2757) document located on the Gas Wiki SharePoint website, and on any written addendum as required.

The information on the Gas Uprating Data sheet and addendum shall include the following:

- Type of work, investigations, and tests performed.
- Documentation of leak surveys performed, including maps used.
- Leaks detected and repaired.
- Pipeline or facility alterations, repairs, or replacements completed.
- Documentation of actual incremental pressure increases and type of gauge or pressure recording devices used.
- Dates and names of persons responsible for each specific uprating task.

Gas Engineering shall retain the documents relating to any uprating procedure (including design specifications) for the life of the pipeline segment.

4.18 ODORIZATION PROCEDURES

SCOPE:

To establish uniform odorant sampling procedures for Avista and to assure that the proper concentration of odorant exists as per applicable codes.

REGULATORY REQUIREMENTS:

§192.625

WAC 480-93-015

CORRESPONDING STANDARDS:

Spec. 2.52, Odorization of Natural Gas
Spec. 5.23, Odorization Equipment

General

This specification details the requirements and procedures necessary to assure that the Company's natural gas supplied to Avista's customers is odorized as required by code. Procedures for adding odorant to the pipeline system, testing to assure even distribution and proper concentration, and recordkeeping are also covered in this specification. Maintenance related to odorization equipment shall be performed by personnel trained and qualified in the maintenance of such odorization equipment and systems.

Natural gas supplied to customers by Avista will be odorized. Natural gas will generally be odorized at or near the gate station except where such gas is adequately odorized as received from the pipeline company.

Odorant Concentrations

Natural gas shall be odorized to a level that will enable detection by a person with a normal sense of smell at a minimum of 20 percent LEL or a minimum of 1.0 percent gas in air. To enhance public safety, it is Avista's intent to odorize the gas to a minimum level of 8 percent of the LEL or a minimum of 0.40 percent gas in air. These levels (often called the Readily Detectable Level) are to be measured and recorded with a Company-approved odorometer.

When sampling odorant and the first read is higher than 0.40 percent gas in air (indicating a lesser concentration of odorant than desired) a second read should be taken to verify the reading. If a second read confirms low odorant levels, the read should be verified by another qualified individual to rule out the possibility of human error. If the low read is confirmed, system changes should be made to address the situation. This can include odorizer or regulator station adjustments. A follow-up read should be completed to confirm adequate odorization levels. The follow-up read is typically done a day or two (or the next business day if the adjustment is made on a Friday, weekend, or a holiday) after the system adjustment is made to allow time for the odorant levels to change. The time required for the adjustment to take effect may depend on the time of year, the system load, and other factors. Additional adjustments may be required to achieve the desired odorant concentration.

When odorization is performed by an interstate pipeline, the applicable operations manager will contact Gas Engineering to initiate odorant level adjustments.

Pickling Newly Installed Piping

Newly installed steel and PE pipelines have a tendency to absorb the odorant from the gas stream. This is especially true for pipelines that are gassed up, but not immediately put into service. “Pickling” is a process to address the problem of lower than adequate odorant being present in the gas stream due to pipe absorption.

The most common way to pickle a pipe is to increase the odorant injection rate at the odorizer supplying gas to this pipeline. This increased injection rate should stay in effect until the pipe walls are no longer absorbing the odorant. Frequent monitoring of the downstream system for adequate odorization should be done to determine when the odorizer can be returned to its previous setting. These actions should be taken with the intent of accomplishing the pickling as soon as possible after putting the pipeline into service. Contact Gas Engineering for further assistance.

Odorant Sampling

Avista shall perform monthly sampling (tests) of natural gas in the system to assure that the proper concentration of odorant exists. These tests shall be performed in accordance with procedures outlined in this specification and in accordance with applicable manufacturer's instructions. The determination of odor intensity shall be made by performing an odorometer test at various customers’ premises. Odorometer tests shall be made at points in the gas distribution system and spaced so as to give an accurate representation of odorant concentrations across the system. The Gas Planning Engineer can assist in specifying general test point locations. New test points shall be established as necessary as system growth occurs.

Test Point Review

Each area shall review their test points once each calendar year. This review shall be noted on the sampling form to determine if existing test points are still valid or if test points have been moved based on the review. Field personnel shall conduct odorometer tests as near to these locations as is practical.

Field personnel are encouraged to allow customers to help perform odorometer sniff tests.

Odorometer sniff tests shall be conducted in an odor-free environment. Persons conducting the tests should have a normal sense of smell and should not perform the test if they have a head cold or other illness that might affect the normal sense of smell. Breath mints, washes, or medicines that can affect the sense of smell shall also not be used prior to conducting the test.

Odorometer test procedures shall follow the manufacturer’s recommendations.

The effectiveness of the distribution of odorant shall be determined from periodic reports made by appropriate, trained field personnel.

Locations Where Odor is Inadequate

Locations where the odorant usage is shown to be inadequate shall be re-checked immediately (refer to the Odorant Concentrations section above). If the re-check indicates that the odorant level is indeed inadequate, field personnel shall proceed to check other locations close to the original location for proper odorant level until the area of inadequacy is completely defined. The cause of the inadequacy shall be determined and addressed as soon as possible, preferably by the end of the next day. Oftentimes the inadequacy can be corrected by odorizer or regulator station adjustments. If unable to determine the cause of the inadequacy, contact Gas Engineering for assistance.

Odorant Level Analysis

Operations personnel shall adjust odorizers as necessary to assure odorant levels remain within specification. Gas Engineering may provide assistance with odorizer level adjustments. If odorization is provided by the gas supplier, the supplier shall be notified of inadequate levels so that adjustments can be made.

Periodic Odorizer Station Inspectors

Odorizer maintenance shall be performed per the requirements outlined in Specification 5.23, Odorizer Equipment.

Recordkeeping

Odorometer sampling results, verification results, and follow-up actions shall be recorded on the Odorizer form (Form N-2621). Completed forms shall be retained for a minimum of 5 years.

YZ ODOROMETER (DTEX):

General

DTEX is a small, handheld instrument, which assists the user in determining the odorant intensity of natural gas with menu-driven step-by-step instructions. The DTEX system can accept inlet pressure from 5-inches WC up to **a maximum of 5 psig**. This unit records the actual air/gas percentage for both threshold detection level (TDL) and readily detectable level (RDL) and can be downloaded into a computer to print a report. This unit is intrinsically safe for hazardous locations Class 1, Division 1, Groups C and D.

Operating Instructions

The following procedures should be followed when testing to determine odorant level in distribution systems using this type of odorometer:

- Always keep the instrument dry. It should be protected from water, open flames, and any other potential source of damage.
- Avoid conducting tests in windy conditions or in closed, confined spaces.
- Operators should be selected with due consideration to smoking habits, colds, and other health conditions since these factors may affect the operator's sense of smell. It is essential to select operators with an average sense of smell in order to obtain reasonable consistent results from the use of the instrument.
- Connect the gas inlet hose to the test source connection and open the source isolation valve.
- Power up the system by pressing the **PWR** button on the keypad. The fan will begin to run automatically as part of a system hardware check.
- Use arrow keys to scroll information in the screen up and down. Press **P** to purge the unit before a test. Open the flow valve fully until you smell gas then close valve and press **Enter** to continue. The gas inlet hose and internal regulator must be filled with gas prior to running a test for accurate test results.
- Continue to follow the step-by-step instructions to sign on and enter location information for each test site.

Threshold Detection Level (TDL)

1. Position nose within 3/4-inch of the sniff chamber and with valve closed sniff exhaust. If an uncharacteristic odor is detected, allow the instrument to operate for an additional two minutes. If uncharacteristic odor persists, perform an exhaust background evaluation test.
2. Slowly open the flow valve and sniff exhaust. Continue to open the flow valve and sniff getting breaths of fresh air between sniffs. Continue the procedure until the first hint of a new odor is detected. This is the threshold detection level (TDL); this is the minimum concentration of gas in air when one detects a new or different odor.
3. Remove nose from sniff chamber.
4. Press the Record Test Level (RTL) key, this records the threshold detection level (TDL).

Read the manufacturer's instructions before operating any instrument. Manufacturer's instructions shall supersede any general instructions in this procedure.

Readily Detectable Level (RDL)

1. Position nose within 3/4-inch of the sniff chamber.
2. Continue to open the flow valve until the readily detectable odor of gas is attained. This is the readily detectable level (RDL), which is the determination that natural gas odor can be positively identified.
3. Remove nose from sniff chamber.
4. Press the **Record Test Level (RTL)** key, this records the readily detectable level (RDL).
5. The test is completed; close valve and press **Enter**.
6. Add any notes such as “windy,” or if there was something that affected the test such as car exhaust then press **Enter**.
7. Press the **PWR** key. Several options will be displayed in the screen. After each test select **V** to vent the unit to prevent undue saturation of inlet hose and system components and residual smell in the unit.
    - Close the source isolation valve.
    - Remove the gas inlet hose from the source of connection.
    - Press **V** to vent
    - Open the flow valve fully
    - Wait until prompted on screen, then close flow valve
    - Press **PWR** to shut down
    -

Exhaust Background Evaluation

Approximately every 30 days the instrument should be checked for an exhaust background evaluation. Without connecting gas to the inlet, power on the unit, open the flow valve fully and press **P** on the keypad to purge the unit. Purge for two minutes before closing the valve and pressing the **Enter** key to conclude the purge procedure. If after two minutes the smell persists over and above normal background, send the unit in to be serviced.

Calibration of Instrument

The DTEX odorometer should be calibrated every two years (Note: The DTEX calibration due date is displayed each time the unit is powered on). This calibration must be performed by the manufacturer and the record of the calibration shall be retained for a minimum of five years. The calibration request to the manufacturer should specifically state for them to perform a “Two Year Calibration” on the unit.

4.19 CREW ACTIVITY REPORTING - WASHINGTON

SCOPE:

To establish a uniform reporting procedure for Avista's construction areas in the state of Washington for reporting crew activities per the applicable code.

REGULATORY REQUIREMENTS:

WAC 480-93-200

CORRESPONDING STANDARDS:

Section 3.0, Construction
Section 5.0, Maintenance

General

This section details the requirements necessary to ensure Avista's construction areas within in the state of Washington, report construction and repair crew activities as required by the Washington Utilities and Transportation Commission (WUTC). WUTC safety inspectors who perform random crew inspections utilize this report and rely heavily on it to be detailed and accurate.

Daily Reporting

Each construction office or entity (including the Gas Facility Replacement Program) shall email (**on a daily basis, no later than 10:00 a.m.),** a list of each crew and where they are scheduled to perform construction and/or repair activities. The list shall be broken down by individual crews and the scheduled work must be listed by address or at a minimum, cross streets and the town or city where the activity is scheduled. (The term "crew" includes Avista crews as well as contract crews that are working for Avista.) Be sure to include a phone number(s) on the report for the person(s) to call if the WUTC needs to verify a crew location or has other questions. Contractors working on behalf of Avista (e.g., GFRP Contractor) may be allowed to directly submit their daily construction reports to the WUTC. Consult with Avista's Pipeline Safety Engineer prior to beginning this process.

The report should contain construction activity and repair activity scheduled for that particular day. Submission of all planned work scheduled for the entire week is acceptable, but the report must be updated and submitted every day and reflect applicable changes / updates to the schedule. If no construction activities are scheduled in a particular construction area, then no report is required.

Submission of Reports

The daily report must be submitted by e-mail to the following e-mail address. (Be sure to include a descriptor in subject line of the email as to the purpose of the email such as "Avista Gas Crew Schedule Colville" or "Crew Notification Ritzville District".)
pipeline@utc.wa.gov

WUTC Contact

If experiencing problems submitting the daily report, call the WUTC office assistant at 360-664-1182 for assistance and to explain the problem. The phone call notifies the WUTC of the attempt to comply with WAC 480-93-200(12).

4.2 CUSTOMER NOTIFICATION

4.22 CUSTOMER OWNED SERVICE LINES

SCOPE:

To establish procedures for ongoing notifications to Avista's gas distribution customers regarding the potential hazards concerning buried downstream gas piping systems and the corresponding remedies and resources available for correction of discovered leakage, damage, or corrosion.

REGULATORY REQUIREMENTS:

§192.16

CORRESPONDING STANDARDS:

None

General

Operators of gas distribution systems are required to make certain notifications to gas customers concerning customer owned service lines and buried customer piping systems.

This rule applies only to operators who do not maintain the customer's buried piping up to entry of the first building downstream of the meter or if the customer's piping does not enter a building, up to the principal gas utilization equipment or the first fence (or wall) that surrounds that equipment.

Required Information

The following items are required to be included in the written notifications:

- Avista does not maintain the customer's piping.
- If a gas customer's piping is not maintained, it may be subject to the potential hazards of corrosion and leakage.
- Buried gas piping should be periodically inspected for leakage and corrosion, as applicable.
- Any unsafe conditions discovered on customer piping should be corrected immediately or as soon as practical, depending on the nature of the problem.
- If customers excavate near buried gas lines, the piping should be located in advance and the excavation should be performed by hand to avoid damage to the pipelines.
- There are resources available to assist in locating, inspecting, and repairing the customer's buried gas lines. These resources include licensed plumbers, dealers, and heating contractors.

One-Time Notification

As required by code, an appropriate written customer notification was prepared and distributed to Avista natural gas customers prior to August 14, 1996. The customer notification included the information required by §192.16, as detailed above.

Ongoing Notification

Natural gas customers shall be notified of the information required by § 192.16 within 90 days after establishing service at a particular location. The written notification may be provided in the new customer information packet/communication, inserted into the first billing, or mailed separately to the customer establishing service.

Customer Service shall be responsible for identifying each new gas customer and for ensuring that the written notification is mailed to the customer within the 90-day time frame.

Recordkeeping

Copies of the written notifications shall be retained by the Pipeline Safety Engineer. Evidence of notifications shall be retained for a period of 3 years.

4.3 AVISTA UTILITIES' OPERATOR QUALIFICATION PROGRAM

4.31 OPERATOR QUALIFICATION

SCOPE:

The purpose of Avista's Operator Qualification Program (OQ Program) is to ensure individuals performing covered tasks on Avista's gas pipelines and facilities are fully qualified in accordance with §192, Subpart N and State regulation. The OQ Program is detailed in a separate document that is maintained by the Manager of Operator Qualification (OQ). The OQ Program outlines accountabilities, responsibilities, and the procedures for identifying covered tasks, evaluation intervals, span of control, recordkeeping requirements, and other administrative practices. The goal of the OQ Program is to help ensure a qualified work force and to reduce the probability and consequence of incidents caused by human error.

As of October 28, 2002, individuals performing covered tasks shall either be qualified or work under the direction of a qualified individual.

REGULATORY REQUIREMENTS:

§191.3, §192.3, §192.756, §192.801, §192.803, §192.805, §192,807, §192.809

WAC 480-93-013, 480-93-999

CORRESPONDING STANDARDS:

See standards referenced by task in Appendix A of this specification.

General

Avista has established and maintains a qualified workforce in accordance with §192 Subpart N, State regulatory requirements, and through incorporation of industry practices. A qualified employee is one that has been evaluated and can perform assigned covered tasks and recognize and react to abnormal operating conditions (AOCs).

OPERATOR QUALIFICATION COVERED TASK LIST – APPENDIX A

TASK INDEX TABLE

<table>
<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.060.010</td><td>Abandon or Inactivate Facilities</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Abandon or inactivate gas pipelines and aboveground facilities. Identify the requirements for abandoning or inactivating gas facilities including discontinuance of gas service to the customer. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
Incomplete purge-re-purge and verify
Uncontrolled release of gas-initiate immediate response
Corrosion-remediate and/or report
Fire or explosion-evacuate and initiate immediate response</td></tr>
<tr><td colspan="3">Standards referenced: Specification 5.13, 5.16</td></tr>
</table>

<table>
<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.020.035</td><td>Avista Side – Leak Investigation</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Respond and investigate a notice of gas leakage and odor calls (Avista-Side) by utilizing leak detection and bar testing equipment, be able to pinpoint and grade a leak. Complete required documentation. Recognize and react to abnormal operating conditions.

Completing this task also satisfies skills required for Leak Survey (221.230.005)</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
Hazardous gas leakage-initiate immediate response
Probe damages/pipe coating-repair or initiate repair
Multiple leaks-pinpoint by bar hole testing
Other gases present-contact property owner/protect life & property
Gas in a duct or sewer system-implement/initiate emergency procedures</td></tr>
<tr><td colspan="3">Standards referenced: Gas Emergency & Service Handbook, Sections 2 & 4.</td></tr>
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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.110.030</td><td>CP-Atmospheric Coating Maintenance</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Inspect and maintain coatings for aboveground piping. Identify the requirements for maintaining coatings on aboveground piping. Using approved materials and procedures, maintain coatings on aboveground pipe. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
Damaged coating-repair coating
Damaged pipe-repair or report
Pitting-repair or report
Corrosion present-repair or report
Gas leak-initiate immediate response</td></tr>
<tr><td colspan="3">Standards referenced: Specification 5.14</td></tr>
</table>

OPERATOR QUALIFICATION COVERED TASK LIST – APPENDIX A

<table>
<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.110.025</td><td>CP-Coating Maintenance for Buried Pipe</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Inspect and maintain coatings for buried pipe. Identify the requirements for maintaining coatings for buried pipe. Using approved materials and procedures maintain coatings on buried pipelines. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Damaged coating-repair coating
• Inadequate coverage or contact-smooth to remove wrinkles, voids; re-wrap and remediate
• Pipe damaged, corroded or pitted- report
• Debris on wrap – remove debris and re-wrap
• Gas leak-initiate immediate response</td></tr>
<tr><td colspan="3">Standards referenced: Specification 3.12, 3.32, 5.14</td></tr>
</table>

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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.110.020</td><td>CP-Identify Atmospheric Corrosion</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Monitor aboveground facilities for corrosion. Inspect aboveground facilities such as regulator stations and meter set assemblies for signs of atmospheric corrosion. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Pitting-repair or replace pipe or fitting
• Corrosion present-report and remediate
• Gas leak-initiate immediate response</td></tr>
<tr><td colspan="3">Standards referenced: Specification 5.14</td></tr>
</table>

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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.110.015</td><td>CP-Identify Corrosion on Buried Pipe</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Inspect buried pipe for corrosion. Inspect for external and internal corrosion on buried pipelines. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Pitting-repair or replace pipe or fitting
• Corrosion present-report and remediate
• Gas leak-initiate immediate response</td></tr>
<tr><td colspan="3">Standards referenced: Specification 3.32, 3.44, 5.14</td></tr>
</table>

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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.110.035</td><td>CP-Install Cathodic Test Leads and Stations</td><td>3 Years</td><td>Skill</td><td>1:1</td></tr>
<tr><td colspan="2" rowspan="2">Description: Install Cathodic test leads and “Fink” test stations. Identify the requirements, tools, materials used to install Cathodic test leads. Using a thermo-weld tool, inspect the pipe, prepare the pipe and tool, and install test wires following written procedures. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Substandard weld-repair and replace
• Gas leak-initiate immediate response
• Fire-evacuate and initiate immediate response</td></tr>
<tr><td colspan="3">Standards referenced: Specification 2.32</td></tr>
</table>

OPERATOR QUALIFICATION COVERED TASK LIST – APPENDIX A

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.110.055	**CP-Pipe to Soil Testing**	**3 Years**	**Skill**	**1:3**
Description: Test pipe to soil potential. Inspect test equipment. Identify the requirements for performing a pipe to soil read. Perform a proper pipe to soil read. Recognize and react to abnormal operating conditions. Note: NACE Certification in any of the following areas meets the Operator Qualification Requirements of this Task: CP1 – Cathodic Protection Tester, CP-2 – Cathodic Protection Technician, CP-3 – Cathodic Protection Technologist, or CP-4 – Cathodic Protection Specialist.		Abnormal Operating Conditions and Remedial Actions: • Low potential read-report to CP technician for action to take • High potential read-report to CP technician for action to take • Dry ground conditions-wet surrounding area **Standards referenced:** Specification 5.14		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.110.050	**CP-Rectifier Inspections**	**3 Years**	**Skill**	**1:3**
Description: Inspect and test rectifiers. Identify the requirements for testing and inspecting a rectifier. Inspect test equipment. Perform output (voltage/amperage) readings and complete required documentation. Recognize and react to abnormal operating conditions. Note: NACE Certification in any of the following areas meets the Operator Qualification Requirements of this Task: CP-2 – Cathodic Protection Technician, CP-3 – Cathodic Protection Technologist, or CP-4 – Cathodic Protection Specialist.		Abnormal Operating Conditions and Remedial Actions: • Low potential read-investigate and initiate repair • High potential read-investigate and initiate repair **Standards referenced:** Specification 5.14		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.120.070	**Damage Prevention**	**3 Years**	**Knowledge**	**1:3**
Description: Prevent damage to pipeline facilities through public education, physical marking, work practices, and inspections. Identify dig laws and requirements for excavating around buried facilities. Educate the public and contractors on the One Call System. Prevent physical damage to facilities when working on or near the facility. Provide on-site inspections of excavation activities near pipeline facilities when necessary.		Abnormal Operating Conditions and Remedial Actions: • Un-marked facility-report to appropriate owner • Damaged facility-report or repair **Standards referenced:** Specification 4.13		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.120.090	**Install and Maintain Casings**	**3 Years**	**Knowledge**	**1:3**
Description: Install and maintain casings. Identify the requirements for installing casings, casing vents, and casing seals. Install casings in accordance with design and written procedures including installing casing vents and seals, Cathodic test leads, and installation to prevent damage to the gas carrier pipe. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Shorted casing-report and remediate • Gas leak-initiate immediate response • Fire-evacuate and initiate immediate response • End seals leaking-repair or replace • Damaged vent pipe-repair or replace **Standards referenced:** Specification 2.32, 3.42, 5.14		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.120.110	**Install and Maintain Pipeline Markers**	**3 Years**	**Knowledge**	**1:3**
Description: Install and maintain gas pipeline markers and signage. Identify the requirements for installing and maintaining various types of pipeline markers. Install pipeline markers as close as practical over distribution and transmission lines. Maintain pipeline markers in accordance with gas standards. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Missing or damaged markers-repair or replace • Improper signage-replace • Signage not legible-replace signage **Standards referenced:** Specification 5.15		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.070.041	**Install Gas Meters: Large Commercial**	**3 Years**	**Skill**	**1:1**
Description: Install, maintain, and protect large commercial meter set assemblies. Identify the codes and standards for meter location, installation, and protection of the large commercial meter set assembly. Purge the service riser and install and protect the meter set in accordance with gas standards requirements. Verify regulator flow and lock up. Adjust regulator set points as needed. Recognize and react to abnormal operating conditions. NOTE: Diaphragm meters (AL1400, AL2300, AL5000) and all rotary meters with a metering pressure of 7" WC, 2 psig, or 5 psig are covered by this task. Completing this task also satisfies skills required for Recognizing Unsafe Meter Sets (221.070.070)		Abnormal Operating Conditions and Remedial Actions: • MSA in an improper location-relocate or vent regulator • MSA and piping under stress-reset or re-pipe • MSA unprotected-barricade, move, coat • MSA is leaking-repair or report • No lock-up - repair or replace • Regulator out of adjustment - adjust set point • Uncontrolled release of gas - initiate immediate response **Standards referenced:** Specification 2.22, 2.23, 2.24 (tables and dwgs), 5.12 and GESH 6.		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.070.045	**Install Gas Meters: Residential and Small Commercial**	**3 Years**	**Skill**	**1:1**
Description: Install, maintain, and protect residential and small commercial gas meter set assemblies. Identify the codes and standards for meter location, installation, and protection of the residential and small commercial meter set assembly. Purge the service riser and install and protect the meter set in accordance with gas standards requirements. Verify regulator flow and lock up. Adjust regulator set points as needed. Recognize and react to abnormal operating conditions. Completing this task also satisfies skills required for Recognizing Unsafe Meter Sets (221.070.070)		Abnormal Operating Conditions and Remedial Actions: • MSA in an improper location-relocate or vent regulator • MSA and piping under stress-reset or re-pipe • MSA unprotected-barricade, move, coat • MSA is leaking-repair or report • No lock-up - repair or replace • Regulator out of adjustment - adjust set point • Uncontrolled release of gas - initiate immediate response **Standards referenced:** Specification 2.22, 2.23, 2.24 (tables and dwgs), 5.12 and GESH 6		

OPERATOR QUALIFICATION COVERED TASK LIST – APPENDIX A

<table>
<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.120.115</td><td>Install Gas Pipelines</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Install gas pipelines. Identify the requirements for storing, handling, and installing gas pipelines. This includes tracer wire requirements (including setting tracer Finks and anodes), trench requirements, plowing and trenching, and various other installation requirements. Install gas pipelines in accordance with gas standards. Recognize and react to abnormal operating conditions.

Note: Tracer wire connections are part of this task.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Pipe exceeds exposure to UV-discard pipe
• Pipe damaged during handling-cut out or replace
• Wire connector fails-replace connector
• Test station missing wire-replace wire
• Pulling force exceeded-replace pipe section
• Pipe coating damaged-replace or repair coating
• Construction standards not met-initiate immediate response to correct.</td></tr>
<tr><td colspan="3">Standards referenced: Specification 3.12, 3.13</td></tr>
</table>

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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.230.005</td><td>Leak Survey</td><td>3 Years</td><td>Skill</td><td>1:1</td></tr>
<tr><td colspan="2" rowspan="2">Description: Leak survey gas pipelines by walking or driving. Identify the requirements for performing leak survey. Inspect, test, and calibrate leak survey instruments as applicable. Perform a walking/mobile leak survey in accordance with gas standards. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Hazardous gas leak-immediately report to 1-800 # to initiate response
• Gas leak-document and/or report</td></tr>
<tr><td colspan="3">Standards referenced: Specification 5.11, 5.19</td></tr>
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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.080.045</td><td>Line Heater Maintenance</td><td>3 Years</td><td>Knowledge</td><td>1:1</td></tr>
<tr><td colspan="2" rowspan="2">Description: Identify the requirements and procedures for maintaining line heaters. Identify the requirements for annual and ten-year maintenance. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Line heater leaking – Repair or replace as required
• Set points out of specification – Adjust as required
• Water / Glycol solution low – Fill according to instructions</td></tr>
<tr><td colspan="3">Standards referenced: Specification 5.22</td></tr>
</table>

OPERATOR QUALIFICATION COVERED TASK LIST – APPENDIX A

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.230.050	**Locate Gas Pipelines**	**3 Years**	**Skill**	**1:1**
Description: Locate and mark gas pipelines. Identify the requirements for locating and marking gas pipelines. Inspect the locating equipment prior to locating gas pipelines. Perform a gas locate using proper tools and techniques. Accurately mark gas facilities by appropriate methods. Recognize and react to abnormal operating conditions. Note: NACE Certification in any of the following areas meets the Operator Qualification Requirements of this Task: CP1 – Cathodic Protection Tester, CP-2 – Cathodic Protection Technician, CP-3 – Cathodic Protection Technologist, or CP-4 – Cathodic Protection Specialist.		Abnormal Operating Conditions and Remedial Actions: • Broken tracer wire-report or remediate • Equipment out of specs-repair or replace • Pipeline un-locatable-report for verification/notify excavator • Gas leak-initiate immediate response • Fire-evacuate and initiate immediate response **Standards referenced:** Specification 4.13		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.230.035	**Monitoring Pipeline Pressures**	**3 Years**	**Knowledge**	**1:3**
Description: Monitor gas pipeline pressures. Identify the requirements for monitoring pipeline pressures. Using chart recorders, telemetry, and other equipment; monitor, gas pipeline pressure to check for abnormal conditions in the gas system. (Does not include upstream / downstream monitoring done during pipe installations.) Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Abnormal pipeline pressures-initiate immediate response **Standards referenced:** Specification 2.23, 2.25, 3.12, 3.13, 3.32, 3.33, 3.34, 4.17, 5.12, 5.21		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.080.047	**Monthly Line Heater Maintenance**	**3 Years**	**Knowledge**	**1:1**
Description: Inspect the line heater for gas and fluid leaks. Inspect set points, fluid levels, temperatures, and pilot light operability. Adjust or repair as required. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Line heater leaking – Repair or replace as required • Set points out of specification – Adjust as required • Water / Glycol solution low – Fill according to instructions • Pilot light inoperable – initiate inspection and repairs by qualified personnel **Standards referenced:** Specification 5.22		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.130.015	**Non-Destructive Testing of Welds .**	**Per API 1104**	**Knowledge**	**Non-Observable***
Description: Non-destructive testing personnel shall be certified to Level I, II, or III in accordance with ASNT (American Society for Nondestructive Testing or equivalent. Only a Level II or III shall interpret the test results. Includes radiographic, magnetic particle, ultrasonic test, and liquid penetrant. Acceptance standards for non-destructive testing shall meet the requirements of Section 9 of API 1104.		Abnormal Operating Conditions and Remedial Actions: • Rejected weld – notify company of reject for remedial action • *An NDT technician may be under a 1:1 span of control for pipeline facility AOC's relating to prevention of accidental ignition **Standards referenced:** Specification 3.12		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.090.025	**Odorization-Odorizer Maintenance**	**3 Years**	**Knowledge**	**1:1**
Description: Maintain odorizers. Identify the requirements and procedures for maintaining odorizers. Maintain, fill, and adjust gas odorizers following manufacturers and standards requirements. Recognize and react to abnormal operating conditions. This task also covers adjusting injection-style odorizers.		Abnormal Operating Conditions and Remedial Actions: • Uncontrolled release of gas-initiate immediate response • Odorant spill-report and initiate immediate response • Gas leak-initiate immediate response • Fire-evacuate and initiate immediate response • Over/under odorization-adjust set points **Standards referenced:** Specification 5.23, 4.18, 2.52		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.090.035	**Odorization-Odorizer Adjustment**	**3 Years**	**Skill**	**1:1**
Description: Identify the requirements and procedures for adjusting odorizers. Recognize and react to abnormal operating conditions. This task covers the adjustment of wick and bypass type of odorizers, not injection type.		Abnormal Operating Conditions and Remedial Actions: • Uncontrolled release of gas-initiate immediate response • Odorant spill-report and initiate immediate response • Gas leak-initiate immediate response • Fire-evacuate and initiate immediate response **Standards referenced:** Specification 4.18		

OPERATOR QUALIFICATION COVERED TASK LIST – APPENDIX A

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.090.030	**Odorization-Periodic Odorant Testing**	**1 Years**	**Skill**	**1:3**
Description: Identify the requirements and procedures for periodic odorant sampling and perform the test using the proper equipment. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Odorant level low-report or remediate • Odorant level high-report or remediate • Equipment out of specs-repair or replace **Standards referenced:** Specification 4.18		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.230.055	**Operate Gas Pipeline – Local Facility Remote-Control Operations**	**3 Years**	**Skill**	**1:1**
Description: Gas Controller monitoring system operations using telemetry and / or pressure devices. Direct manual operations of pressure regulating equipment and valves. Recognize and respond to abnormal operating conditions (alarms) by notifying field personnel to respond and take action.		Abnormal Operating Conditions and Remedial Actions: • Loss of SCADA Communications-Notify field technician and monitor • High/Low Pressure- Notify field technician and monitor • High/Low Temperature- Notify field technician and monitor • Improper Odorizer Operation- Notify field technician • Indication of Safety-Related Condition- Notify field technician • High Flow- Notify field technician and monitor **Standards referenced:** Specification 4.51		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.230.001	**Patrolling Gas Pipelines**	**3 Years**	**Knowledge**	**1:1**
Description: Patrol gas pipelines by walking, driving, or flying for the specific purpose of observing conditions that may affect the safety and operation of transmission pipeline and selected distribution facilities. Identify the requirements for patrolling gas pipelines. Patrol gas pipelines inspecting for signs of soil subsidence, encroachment, gas leaks, and missing or damaged pipeline markers and signage. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Encroachment-report for follow up • Washouts-report for follow up • Gas leaks-report for follow up • Missing/damaged markers-report for follow up **Standards referenced:** Specification 5.11, 5.15		

OPERATOR QUALIFICATION COVERED TASK LIST – APPENDIX A

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.030.001	**PE Pipe Joining - Electrofusion**	**1 Year**	**Skill**	**Non-Observable**
Description: Electro fuse PE pipe and fittings. Properly inspect pipe joining equipment and associated tools prior to joining. Clean, inspect, and prepare pipe and fittings for joining. Using an electro fusion processor, properly join and inspect an electro fusion coupling or electro fusion tee on PE pipe. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Inclement weather-shield or cover joining process • Equipment out of specs-repair or replace equipment • Visual inspection unacceptable-replace bad joint **Standards referenced:** Specification 3.24		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.030.010	**PE Pipe Joining -Hydraulic Butt Fusion**	**1 Year**	**Skill**	**Non-Observable**
Description: Hydraulically butt fuse PE pipe. Properly inspect pipe joining equipment and associated tools prior to joining. Clean, inspect, and prepare the pipe for joining. Using hydraulic butt fusion equipment, properly perform and visually inspect a butt fusion. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Inclement weather-shield or cover joining process • Equipment out of specs-repair or replace equipment • Visual inspection unacceptable-replace bad joint • See troubleshooting table in Spec 3.23 **Standards referenced:** Specification 3.23		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.030.005	**PE Pipe Joining - Manual Butt Fusion**	**1 Year**	**Skill**	**Non-Observable**
Description: Manually butt fuse PE pipe. Properly inspect pipe joining equipment and associated tools prior to joining. Clean, inspect, and prepare the pipe for joining. Using mechanical butt fusion equipment, properly perform and visually inspect a butt fusion. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Inclement weather-shield or cover joining process • Equipment out of specs-repair or replace equipment • Visual inspection unacceptable-replace bad joint • See troubleshooting table in Spec 3.23 **Standards referenced:** Specification 3.23		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.030.020	**PE Pipe Joining - Mechanical Couplings**	**1 Year**	**Skill**	**Non-Observable**
Description: Install mechanical slip-lock or compression fittings. Clean, inspect, and prepare the pipe and slip-lock or compression fitting prior to joining. Properly install and visually inspect the mechanical fitting. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Damaged fitting-replace fitting • Damaged pipe-repair or replace pipe • Pipe joint leaks-replace fitting **Standards referenced:** Specification 3.25		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.030.015	**PE Pipe Joining - Mechanical Service Tees**	**1 Year**	**Skill**	**Non-Observable**
Description: Install bolted mechanical service tees to PE pipe. Clean, inspect, and prepare the pipe and fitting prior to joining. Properly install and visually inspect a mechanical service tee on PE pipe. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Damaged fitting-replace fitting • Damaged pipe-repair or replace pipe • Pipe joint leaks-replace fitting **Standards referenced:** Specification 3.25		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.030.025	**PE Pipe Joining - Mechanical Spigot and Sleeve Type Fittings**	**1 Year**	**Skill**	**Non-Observable**
Description: Install spigot and sleeve type mechanical fittings. Clean, inspect, and prepare the pipe fitting prior to joining. Properly install and visually inspect a spigot and sleeve type mechanical fitting. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Damaged fitting-replace fitting • Damaged pipe-repair or replace pipe • Pipe joint leaks-replace fitting **Standards referenced:** Gas Standards Manual Specification 3.25		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.120.085	**Pipe Bending**	**3 Years**	**Knowledge**	**1:3**
Description: Bend steel or PE pipe. Identify the requirements and procedures for performing pipe bends in the field. Describe procedures for bending pipe using appropriate methods so as to avoid damage to the pipe. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Bending radius exceeded--replace pipe section • Mechanical damage such as wrinkle bends, cracks—replace pipe section **Standards referenced:** Specification 3.12, 3.13		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.100.065	**Pipe Squeezing**	**3 Years**	**Skill**	**1:1**
Description: Squeeze off PE pipe. Using the proper squeeze tool, squeeze off PE pipe following the procedure for squeezing and follow written static electricity grounding procedures. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Pipe damage-replace section of pipe • Loss of pressure or overpressure (failure to monitor pressure)-initiate emergency shutdown procedure • Incomplete shutdown-move squeezers and squeeze again or use second squeezer • Gas leak-initiate immediate response • Fire-evacuate and initiate immediate response **Standards referenced:** Specification 3.34		

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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.120.120</td><td>Pipeline Cover, Clearance, & Backfill</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Provide proper depth for gas pipelines. Identify pipeline cover, clearance, and backfill requirements. Install gas pipelines with the minimum requirements established by code. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Minimum cover not met-provide protection to pipe or contact gas engineering for remedial action
• Clearances not met—provide protection or move facility
• Backfill material not suitable-remove and replace
• Trench bottom not suitable-pad trench bottom
• Settlement-provide proper compaction</td></tr>
<tr><td colspan="3">Standards referenced: Specification 3.15</td></tr>
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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.120.075</td><td>Pressure Testing Gas Pipelines</td><td>3 Years</td><td>Knowledge</td><td>1:1</td></tr>
<tr><td colspan="2" rowspan="2">Description: Pressure test gas pipelines for leakage. Identify the requirements for pressure testing gas pipelines. Describe testing procedures for gas lines using gas, air, and inert gas for indications of leakage. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Overpressure the pipeline-report and retest
• Pressure drop-investigate, remediate, and re-test
• Pipeline failure-repair or replace and retest</td></tr>
<tr><td colspan="3">Standards referenced: Specification 3.18</td></tr>
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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.230.040</td><td>Prevention of Accidental Ignition</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Prevent accidental ignition. Identify, recognize, and remove potential ignition sources common to the job site. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Fire-initiate immediate response
• Combustible atmosphere – secure the area and monitor levels, implement EOP plan</td></tr>
<tr><td colspan="3">Standards referenced: Specification 3.17, GESH Section 4</td></tr>
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<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.120.080</td><td>Purging Gas Pipelines</td><td>3 Years</td><td>Knowledge</td><td>1:3</td></tr>
<tr><td colspan="2" rowspan="2">Description: Purge gas pipelines. Identify the requirements, tools, equipment, and techniques that are needed to safely purge a gas pipeline. Purge the gas pipeline in a manner so as to achieve 100 percent of gas in air or 0 percent gas in air. Recognize and react to abnormal operating conditions.</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Incomplete purge-purge and re-test
• Gas leak-initiate immediate response
• Fire-evacuate and initiate immediate response</td></tr>
<tr><td colspan="3">Standards referenced: Specification 3.17</td></tr>
</table>

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.070.070	**Recognizing Unsafe Meter Sets**	**3 Years**	**Knowledge**	**1:3***
Description: Recognize meter sets that may be subject to safety-related and other risks, such as possible leaks, foreign wire, stresses to piping or other physical damage, inoperable (obscured) service valves, overbuilds, unauthorized attachments to meters, and diversion of gas service. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Identification of non-safety-related risk—report for follow up action • Identification of safety-related risk—initiate immediate response. **Standards referenced:** Specification 2.22, 5.14		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.080.035	**Regulator Station - 5/10 Year Maintenance**	**3 Years**	**Skill**	**1:1**
Description: Identify the maintenance requirements for 5/10 year maintenance and perform maintenance. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Uncontrolled release of gas-initiate immediate response • Gas leak-initiate immediate response • Overpressure of the system-report and investigate downstream system • Fire-evacuate and initiate immediate response **Standards referenced:** Specification 5.12		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.080.030	**Regulator Station - Annual Maintenance**	**3 Years**	**Skill**	**1:1**
Description: Identify the maintenance requirements and perform annual maintenance on all configurations of regulator stations. Recognize and react to abnormal operating conditions. Note: Pilot heater maintenance is included in this task.		Abnormal Operating Conditions and Remedial Actions: • Uncontrolled release of gas-initiate immediate response • Gas leak-initiate immediate response • Overpressure of the system-report and investigate downstream system • Fire-evacuate and initiate immediate response **Standards referenced:** Specification 5.12		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.080.025	**Regulator Station - Bypassing**	**3 Years**	**Skill**	**1:1**
Description: Bypass a regulator station. Bypass a regulator station or industrial meter set with like equipment for maintenance and emergency situations following written procedures. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Overpressure the system-report and investigate downstream system • Gas pressure loss-initiate immediate response • Uncontrolled release of gas-initiate immediate response • Gas leak-initiate immediate response • Fire-evacuate and initiate immediate response **Standards referenced:** Specification 5.12		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.060.015	**Repair Gas Pipelines**	**3 Year**	**Knowledge**	**1:3**
Description: Repair gas pipelines. Identify the requirements and methods for repairing gas pipelines including the use of permanent repair leak clamps and sleeves such as the “PLIDCO” and “Clock Spring”. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Mechanical damage-refer to pipe repair chart • Corrosion damage-refer to pipe repair chart • Leaks in welds-refer to pipe repair chart • Non-leaking cracks or defects-refer to pipe repair chart • Leaks in body of fittings or clamps-refer to pipe repair chart • Uncontrolled release of gas-initiate immediate response **Standards referenced:** Specification 3.32, 3.32A, 3.32A, 3.33		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.070.020	**Replace Service Valves**	**3 Years**	**Skill**	**1:1**
Description: Replace broken, damaged, or other non-compliant gas service valves. Using the Mueller “No-Blo” service valve changing equipment, remove the broken, damaged, or non-compliant valve and replace with a new valve. Includes operation and lubrication of service valves. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Equipment out of specs.-repair or replace as needed • Equipment failure during operation-assess situation and take appropriate action • Defective riser-report or repair • Incomplete shutdown-remove, inspect, and repeat • Hazardous gas leakage-initiate immediate response • Fire or explosion-initiate immediate response **Standards referenced:** Specification 2.14, 2.24, 3.16, 5.13, 5.17, GESH Section 9		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.040.001	**Tapping and Stopping - Mueller 4” and Smaller**	**3 Years**	**Skill**	**1:1**
Description: Inspect tapping and stopping equipment prior to operation. Review manufacturer’s instruction for using tapping and stopping equipment prior to operation. Using Mueller tapping and stopping equipment, properly tap and stop steel gas fittings 4 inches in diameter and smaller following manufacturer’s written procedures. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Equipment out of specs-repair or replace • Incomplete shut down-remove stopper and inspect or re-sweep • Hazardous gas leak-initiate immediate response • Line pressure drops-remove stopper plug and evaluate. • Line pressure loss-initiate emergency shutdown and restoration procedure.		
		Standards referenced: Specification 3.32		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.040.010	**Tapping and Stopping - Mueller 6” and Larger**	**3 Years**	**Skill**	**1:1**
Description: Inspect tapping and stopping equipment prior to operation. Review manufacturer’s instruction for using tapping and stopping equipment prior to operation. Using Mueller tapping and stopping equipment, properly tap and stop steel gas fittings 6 inches in diameter and larger following manufacturer’s written procedures. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Equipment out of specs-repair or replace • Incomplete shut down-remove stopper and inspect or re-sweep • Hazardous gas leak-initiate immediate response • Line pressure drops-remove stopper plug and evaluate. • Line pressure loss-initiate emergency shutdown and restoration procedure		
		Standards referenced: Specification 3.32		

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.040.005	**Tapping and Stopping - TDW 4” and Smaller**	**3 Years**	**Skill**	**1:1**
Description: Inspect tapping and stopping equipment prior to operation. Review manufacturer’s instruction for using tapping and stopping equipment prior to operation. Using TD Williamson tapping and stopping equipment, properly tap and stop steel gas fittings 4 inches in diameter and smaller following manufacturer’s written procedures. Recognize and react to abnormal operating conditions.		Abnormal Operating Conditions and Remedial Actions: • Equipment out of specs-repair or replace • Incomplete shut down-remove stopper and inspect or re-sweep • Hazardous gas leak-initiate immediate response • Line pressure drops-remove stopper plug and evaluate • Line pressure loss-initiate emergency shutdown and restoration procedure		
		Standards referenced: Specification 3.32		

OPERATOR QUALIFICATION COVERED TASK LIST – APPENDIX A

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.040.015	**Tapping and Stopping - TDW 6” and Larger**	**3 Years**	**Skill**	**1:1**

Description: Inspect tapping and stopping equipment prior to operation. Review manufacturer’s instruction for using tapping and stopping equipment prior to operation. Using TD Williamson tapping and stopping equipment, properly tap and stop steel gas fittings 6 inches in diameter and larger following manufacturer’s written procedures. Recognize and react to abnormal operating conditions.

Abnormal Operating Conditions and Remedial Actions:
- Equipment out of specs-repair or replace
- Incomplete shut down-remove stopper and inspect or re-sweep
- Hazardous gas leak-initiate immediate response
- Line pressure drops-remove stopper plug and evaluate
- Line pressure loss-initiate emergency shutdown and restoration procedure

Standards referenced: Specification 3.32

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.050.005	**Valve Maintenance**	**3 Years**	**Knowledge**	**1:1**

Description: Maintain distribution and transmission valves. Accurately locate and identify the valve to be maintained. Inspect the valve box and valve for signs of damage or leakage. Partially operate the valve. Lubricate the valve as needed. Verify documentation is accurate. Recognize and react to abnormal operating conditions.

Abnormal Operating Conditions and Remedial Actions:
- Valve box out of alignment-excavate and repair
- Valve inoperable-repair or replace
- Valve leaking-repair or replace
- Hazardous gas leakage-initiate immediate response

Standards referenced: Specification 2.14, 5.13

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.080.020	**Vault Maintenance**	**3 Years**	**Knowledge**	**1:3**

Description: Inspect and maintain vaults. Identify the requirements for vault inspection and maintenance. Inspect vaults for damage and repair as needed. Recognize and react to abnormal operating conditions.

Abnormal Operating Conditions and Remedial Actions:
- Gas leak-initiate immediate response
- Fire-evacuate and initiate immediate response
- Poor physical condition-initiate repairs
- Plugged drains or vents-clear obstructions

Standards referenced: Specification 2.22, 2.42, 3.12, 5.18

TASK		EVALUATION INTERVAL	EVALUATION METHOD	SPAN OF CONTROL
221.130.005	**Visual Inspection of the Weld**	**3 Years**	**Knowledge**	**1:1**

Description: Visually inspect weld joints. Verify the weld procedure is being followed this includes checking the joint and alignment, preheat requirements, amp and voltage settings, measure and calculate speed of travel, look for visual weld defects. Recognize and react to abnormal operating conditions.

Abnormal Operating Conditions and Remedial Actions:
- Weld defects (porosity overlap, undercut, cracking, contaminants) – repair or cut out weld

Standards referenced: Specification 3.22

OPERATOR QUALIFICATION COVERED TASK LIST – APPENDIX A

<table>
<tr><th colspan="2">TASK</th><th>EVALUATION INTERVAL</th><th>EVALUATION METHOD</th><th>SPAN OF CONTROL</th></tr>
<tr><td>221.130.010</td><td>Welding</td><td>6 Months</td><td>Skill</td><td>Non-Observable</td></tr>
<tr><td colspan="2" rowspan="2">Description: Joining of steel pipe by welding. Perform fit up and weld of joint in accordance with applicable company welding procedure and process which includes the use of the appropriate electrode, voltage, amperage, and speed of travel. Recognize and react to abnormal operating conditions. Individuals qualified to this standard also satisfy the skills required for Visual Inspection of the Weld (221.130.005).</td><td colspan="3">Abnormal Operating Conditions and Remedial Actions:
• Correct procedure not followed – cut out weld
• Defects in weld – repair or cut out weld</td></tr>
<tr><td colspan="3">Standards referenced: Specification 3.22</td></tr>
</table>

COVERED TASKS ASSOCIATED WITH INTEGRITY MANAGEMENT, SUBPART O

TASK	EVALUATION INTERVAL
Excavation and Assessment of Pipelines	*As Necessary*
Hydrostatic Testing	*As Necessary*
Metal Loss Assessment	*As Necessary*
Dent Assessment	*As Necessary*
Grinding Repairs	*As Necessary*
Repair of Leaking Defects	*As Necessary*
Installation of Steel Pressure Containing Sleeves	*As Necessary*
Installation of Composite Sleeves	*As Necessary*
Assessment of Arc Burns and Hard Spots	*As Necessary*
In-Line Inspection	*As Necessary*

APPENDIX B
EVALUATION GUIDELINES

Preparation:

(1) Acquiring and developing evaluation skills.
(2) Reviewing applicable performance Criteria Guide(s).
(3) Reviewing applicable performance criteria documents, i.e.:
    (a) Operation and maintenance procedures.
    (b) Engineering specifications.
    (c) Manufacturer's instructions.
(4) Coordinate with individuals on timeframe and location of evaluation.
(5) If utilizing a simulation, make sure all props and necessary equipment are available and ready.

Evaluation:

(1) Select correct documents.
    (a) Criteria Guide(s).
    (b) Record of Evaluation (ROE)

(2) Prepare the individual.
    (a) Explain scope and process of evaluation(s).
    (b) Answer any administrative questions.
    (c) Remind individual to verbalize and demonstrate.
    (d) Be careful how you ask questions – you want to probe not coach.
    (e) Remind individual to identify Abnormal Operating Conditions (AOC).
    (f) Performance evaluation – not memory test.
    (g) Give examples of what "verbalization" means.
    (h) Not a timed test.

(3) Assess individual.
    (a) Monitor safety.
    (b) Evaluate individual's performance in accordance with establish criteria.
    (c) Question individual without giving away information.
    (d) Verify ability to recognize and react to AOCs.
    (e) Mark the ROE as the evaluation progresses.
    (f) Indicate reason(s) unsatisfactory performance.
    (g) Mark successful or unsuccessful completion of each step.
    (h) Mark successful or unsuccessful completion of the evaluation(s).
    (i) Review results with individual.

After Evaluation:

(1) Complete required documentation.
(2) Submit for entry in record keeping system.
(3) If required, take action to schedule individual for re-evaluation or remedial training.
(4) If unable to pass evaluation after remedial training, the individual's manager will be contacted to determine subsequent action.

APPENDIX C
OPERATOR QUALIFICATION
REVIEW FORM

Individual Qualification
Mutual Assistance Qualification

Name of Individual (whose qualifications are being reviewed):

Company OQ Program/Criteria being reviewed:

Compare the evaluation criteria and procedures for any listed covered tasks and associated abnormal operating conditions (AOCs) to ascertain if they are comparable to Avista's OQ Program and O&M Plan.

List of Covered Tasks (and AOC's)/Procedures	Avista Tasks	Acceptable	
		Yes	No

Comments:

____

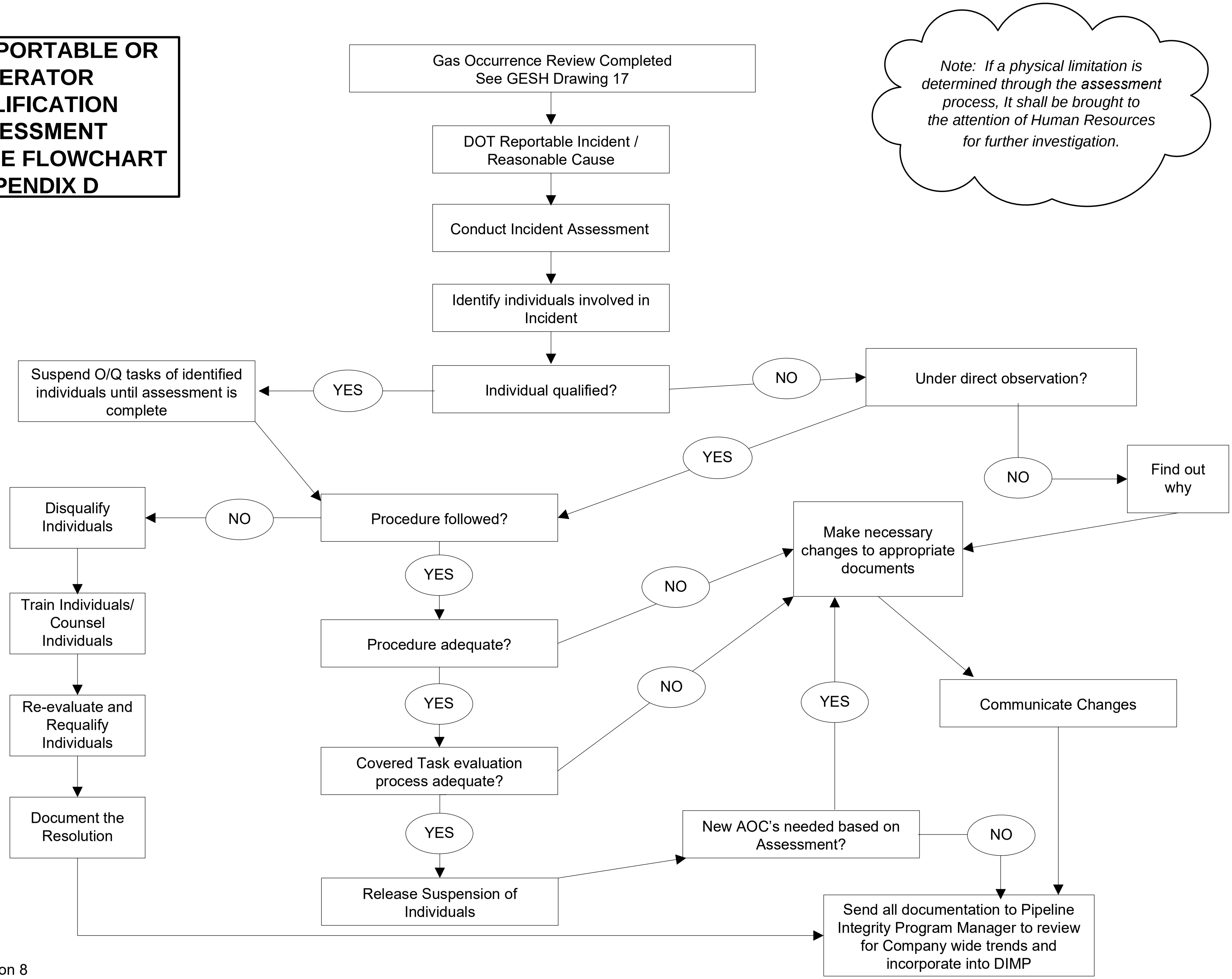
____

Proof of qualifications available:

Reviewed by (name, title, date):

(Attach any documents to support the decision for acceptance)

POST REPORTABLE OR OPERATOR QUALIFICATION ASSESSMENT GUIDELINE FLOWCHART APPENDIX D



4.4 INTEGRITY MANAGEMENT PROGRAM

4.41 TRANSMISSION INTEGRITY MANAGEMENT PROGRAM (TIMP)

The Transmission Integrity Management Program (TIMP) is a separate document that is maintained by the TIMP Program Manager. This document is accessible on the Company's Gas Wiki SharePoint website.

The following standard gives a general overview of what is contained within this document.

SCOPE:

The purpose of Avista's Transmission Integrity Management Program (TIMP) is to provide safe, reliable, and cost-effective transportation of natural gas for our customers without adverse effects on the public, customers, employees, and the environment.

The TIMP is specifically intended to apply only to segments of transmission pipelines subject to the requirements of §192, Subpart O.

This program provides for the comprehensive, integrated, and systematic management of pipeline integrity in high consequence areas (HCA), medium consequence areas, and Class 3 or Class 4 areas operating at a hoop stress of 30% SMYS or more, as a means to improve the safety of the covered pipeline systems. This program provides the necessary framework for Avista to effectively allocate resources for appropriate prevention, detection, and mitigation activities that will result in improved safety. This program provides a process to assess and mitigate risks in order to reduce both the likelihood and consequences of pipeline failures.

REGULATORY REQUIREMENTS:

§192, Subpart O

CORRESPONDING STANDARDS:

Spec. 4.13, Damage Prevention Program
Spec. 4.14, Recurring Reporting Requirements
Spec. 4.31, Operator Qualification
Spec. 5.11, Leak Survey

INTEGRITY MANAGEMENT PRINCIPLES:

Avista has adopted a set of principles as the basis for the intent and specific details of this program. The principles are presented below:

- Functional requirements for integrity management shall be engineered into new pipeline systems from initial planning, design, material selection, installation, and initial inspection and testing. Avista follows the applicable laws and regulations as well as uses numerous consensus codes and standards in order to meet this requirement. Policies, plans, and procedures have been developed which are also used to meet this requirement.

- System integrity requires commitment by operating personnel using systematic, comprehensive, and integrated processes in order to safely operate and maintain the pipeline systems.

- The TIMP will be continuously evolving and improving and is therefore intended to be flexible. Periodic evaluation is conducted to ensure that the program takes appropriate advantage in improvements in technologies and that the program utilizes the appropriate prevention, detection, and mitigation activities. The effectiveness of the various activities will be reassessed and modified to ensure the continuing effectiveness of the program and its activities. The integration of information is recognized as a key component for managing system integrity. Information that can impact the understanding of the important risks to a pipeline system comes from a variety of sources. Avista is committed to analyzing pertinent information in order to effectively manage pipeline integrity.

- Avista has developed a risk assessment methodology and will use that methodology to determine the types of adverse events or conditions that may impact pipeline integrity. The process is also used to prioritize the pipeline segments for further assessment by considering the likelihood and consequence of an adverse event. The model employs a risk algorithm that was custom-designed to accommodate Avista's unique system configuration and data resources.

- Avista will continually gather new and/or additional information pertaining to system configuration and system experience. The Integrity Management Plan will be reviewed on a regular basis to ensure that new information becomes integrated into the Integrity Management Plan.

- Avista is committed to keeping abreast of new knowledge and technologies affecting pipeline integrity and evaluating those technologies and implementing them where appropriate. Avista personnel will attend meetings and conferences and will perform literature searches in order to investigate and then evaluate the use of new technologies for specific use in the TIMP. New technologies and knowledge will be gathered and integrated into the Integrity Management Plan as appropriate.

- Avista has determined the set of performance measures that will best serve the need for monitoring and evaluating the effectiveness of the TIMP. Reports, based on these performance measures, will be generated on an annual basis.

- Avista is committed to communicating the results of its integrity management activities to its stakeholders.

4.42 DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM

The Distribution Integrity Management Program (DIMP) is a separate document that is maintained by the Pipeline Integrity Program Manager. This document is accessible on the Company's Gas Wiki SharePoint website.

The following standard gives a general overview of what is contained within this document.

SCOPE:

The purpose of Avista's DIMP program is to enhance safety by identifying and reducing gas distribution pipeline integrity risks to the public, customers, employees, and the environment. The effective date of Avista's DIMP program was August 2, 2011.

The program outlined in the DIMP document applies to distribution facilities subject to the requirements of §192, Subpart P.

REGULATORY REQUIREMENTS:

§192, Subpart P

CORRESPONDING STANDARDS:

Spec. 3.44, Exposed Pipe Evaluation
Spec. 4.11, Continuing Surveillance
Spec. 4.14, Recurring Reporting Requirements
Spec. 4.31, Operator Qualification
Spec. 5.11, Leak Survey
GESH Section 2, Leak and Odor Investigation

General

Operators must integrate reasonably available information about their pipelines to be used in their risk decisions. The rule requires that operators identify risks to their pipelines where an incident could cause serious consequences and focus priority attention in those areas. The rule also requires that operators implement a program to provide greater assurance of the integrity of their pipeline.

The integrity management approach was designed to promote continuous improvement in pipeline safety by requiring operators to identify and invest in risk control measures beyond previously established regulatory requirements.

DISTRIBUTION INTEGRITY MANAGEMENT ELEMENTS:

The DIMP Plan addresses the following elements:

1. Written Distribution Integrity Management Plan document.

2. Knowledge of the System – Demonstrate an understanding of Avista's infrastructure using reasonably available information from past and ongoing design, operations, and maintenance activities. Identify additional information necessary and develop a plan to obtain that information over time through normal activities.

3. Identify Threats – Identify existing gas distribution pipeline threats through available data including leak repair, incident data, material failure reports, operational and maintenance history, excavation damages, and exposed piping inspection reports. Identify potential threats that have not occurred but based on geographical location may occur such as earthquakes, flooding, and other natural hazards, or have been identified by other organizations such as National Transportation Safety Board, Pipeline and Hazardous Material and Safety Administration, or industry associations.

4. Evaluate and Rank Risks – Develop a process to identify what factors affect the risk posed by the threats identified and where they are relatively more important than others based on likelihood of failure and the potential consequences of the failure.

5. Identify and Implement Measures to Address Risks – Develop risk control measures to address the risks that have been evaluated and prioritized.

6. Measure Performance, Monitor Results, and Evaluate Effectiveness – Establish performance measures that are monitored from an established baseline in order to evaluate the effectiveness of the DIMP program. There are four performance metrics that are required to be monitored to evaluate the effectiveness of the program.

    - Number of Hazardous Leaks either Eliminated or Repaired, Categorized by Cause
    - Number of Hazardous Leaks Eliminated or Repaired, Categorized by Material
    - Total Number of Leaks Eliminated or Repaired, Categorized by Cause
      Number of Excavation Damages, Locate Tickets, and the Ratio of Excavation Damages per 1000 Locate Tickets

7. Reporting of Results – The annual report which includes the four above mentioned performance metrics is required to be completed and submitted to PHMSA each calendar year.

8. Periodic Evaluation and Improvement – Periodically re-evaluate threats and risks on the entire pipeline and periodically evaluate the effectiveness of the program. A complete program re-evaluation shall be completed every five (5) years.

4.51 GAS CONTROL ROOM MANAGEMENT PLAN

The Gas Control Room Management Plan is a separate document maintained by Operations Support. This document is accessible on the Gas Control Room SharePoint site.

The following information gives a general overview of what is contained within this document.

SCOPE:

The requirements in the Gas Control Room Management Plan apply to Avista's Gas Control Room in Spokane, Washington, which monitors the pipelines/systems in the states of Idaho, Oregon, and Washington.

REGULATORY REQUIREMENTS:

§192.619, §192.631

WAC 480-93-018, 480-93-180

CORRESPONDING STANDARDS:

Spec. 2.25, Telemetry Design
Spec. 4.15, Maximum Allowable Operating Pressure (MAOP)
Spec. 4.31, Operator Qualification

CONTROL ROOM MAJOR ELEMENTS:

The Gas Control Room Management Plan includes the following sections, as applied to Gas Control:

- Control Room Management Plan Introduction
- Roles, Responsibilities, Accountability, and Authority of Gas Control Personnel
- Providing Adequate Information to Gas Control Room Personnel – SCADA Processes
- Providing Adequate Information to Gas Control Room Personnel – Shift Change and Other Procedures
- Fatigue Risk Management System
- Alarm Management Plan
- Change Management Plan
- Operating Experience Program
- Control Room Training Program
- Compliance and Deviations
- Activity Review Process

Control Room Notifications

Field personnel shall contact Gas Control when emergency conditions exist or when working on location as described below at a gate station, regulator station, meter set, or other facility known to have telemetry.

Before performing maintenance, operations, or construction activities that may affect Control Room operations, Gas Control must be called at 509-495-4859 or via radio to notify them of the work. This includes valve operations including sensing lines to instrumentation and regulators, set point changes, work on or testing of regulators, instrument calibrations, piping configuration changes, increasing or decreasing the pressure of the system, and other activities that may result in an alarm or alert condition being sensed and transmitted. This will minimize false alarm/alert notifications and associated personnel call outs.

Activities that do not potentially affect gas pressures, gas temperatures, or alarms, such as site maintenance, reading of odorizer levels, fencing construction and/or vegetation management, etc., do not require notification.

When work is complete, Gas Control must be called again to ensure alarms and alerts have cleared before leaving the site.

4.61 QUALITY ASSURANCE / QUALITY CONTROL (QA/QC) PROGRAM

SCOPE:

The purpose of Avista's QA/QC Program is to enhance the quality of gas field activities and improve standardization and efficiency of these activities. The QA/QC Program is designed to audit field activities and not to direct work in the field which is the function of Company and contract inspectors.

REGULATORY REQUIREMENTS:

§192.605 (b)(8)

CORRESPONDING STANDARDS:

Spec. 3.12, Pipe Installation – Steel Mains
Spec. 3.13, Pipe Installation – Plastic Mains
Spec. 3.15, Trenching & Backfilling
Spec. 3.16, Pipe Installation – Services
Spec. 3.17, Purging of Pipelines
Spec. 3.18, Pressure Testing
Spec. 3.22, Joining of Pipe-Steel
Spec. 3.23, Joining of Pipe – Plastic Heat Fusion
Spec. 3.24, Joining of Pipe – Electrofusion
Spec. 3.25, Joining of Pipe – Mechanical

General

The Quality Assurance Program is a separate document that is maintained by the Quality Assurance Manager.

Quality Assurance (QA) comprises those actions necessary to provide adequate confidence that products, processes, or systems comply with applicable specifications and standards. The focus is on providing assurance that processes are adequate and effective.

Quality Control (QC) comprises operational techniques and activities, including audits, necessary to control the characteristics of a product or service (i.e., characteristics that can be measured against codes, drawings, or specifications). The focus is on preventing defective products or services.

Objectives of the QA/QC Program

The QA/QC Program is structured to meet the following objectives:

1. Ensuring adherence to federal, state, and Company requirements, standards, policies, and procedures.
2. Identifying areas in which the Company's standards may need to be updated or clarified.
3. Evaluating the transfer of training/qualifying to the field and identifying training/qualification needs.
4. Providing support to Field Supervisors, Trainers, and Operator Qualification (OQ) Specialists.
5. Presenting recommendations by Avista Utilities Gas Managers and Supervisors to the QA Committee and applicable groups.
6. Facilitating and driving change through direction from the QA Advisory Committee.

Program Applicability

The QA/QC Program applies to the following categories of activities:

Construction
- New construction
- Reconstruction
- Conversions
- Extensions
- Other work (e.g., relocations, cut offs, grading, replacements, maintenance, etc.)
- Pre and Post Paperwork

Gas Service
- Meter work
- Service calls (Inside service work)
- Odor calls
- Maintenance
- Gas Emergencies

Leak Survey
- Surveys
- Odor calls
- Leak re-checks
- Leak resolution

Locating
- One Call locates
- Standbys
- Pipe Ids
- Damage Prevention

Pipeline Marker Program
- Survey

Atmospheric Corrosion (AC)
- Survey
- Follow up on write up

Emergency Response
- Incident Commander (IC)
- Personal Protective Equipment (PPE)
- Public Safety
- Communications
- Response Time
- Local and State Emergency services

Additionally, the QA/QC Program applies to the following employees:

1. Avista natural gas employees
2. Avista gas construction and contract construction crews, including those working with Avista gas crews
3. Avista contractors performing leak survey, atmospheric corrosion, and pipeline marker survey inspections
4. Avista field support employees and contract employees who perform natural gas locating activities.

4.62 INCIDENT ASSESSMENT, FAILURE ASSESSMENT AND LESSONS LEARNED

SCOPE:

Establish a framework for assessment of incidents, failures and near misses, and address findings by identifying corrective action recommendations to prevent or minimize the consequences of a future incident and communication of lessons learned.

REGULATORY REQUIREMENTS:

§192.617

CORRESPONDING STANDARDS:

Spec. 4.31, Appendix D, Post-Reportable OQ Assessment Guideline Flowchart
GESH 17., Incident Investigation

General

Incidents and failures resulting from materials, procedures, and operations should be reviewed for the benefit of determining causation / contributing factors and organizational learning to prevent similar occurrences in the future. This specification provides a framework of how Avista conducts incident assessments and develops, implements, and incorporates lessons learned into Avista written procedures. These procedures include personnel training, qualification, design, construction, testing, maintenance, operations, and emergency procedure manuals and specifications. The words “assessment” and “investigation” can be used interchangeably at times by various people and entities. See the Glossary for definitions of Incident Assessment and Field Investigation.

SITUATIONS THAT TRIGGER ASSESSMENTS

Assessments can be performed for any of the following situations.

1. Material Failures
2. DOT Reportable Incidents
3. Noticeable trends (Multiple Occurrences)
4. Gas related fires and/or explosions
5. Non-gas related fires and/or explosions
6. Personnel Injury
7. Third-Party Damages
8. Pipeline Ruptures and/or Rupture Mitigation Valve (RMV) Closures
9. Near Misses
10. Other management-directed reasons

Material Failure Assessment

A leak marked as a material failure must have a Gas Material Failure Report (Form N-2614) filled out and sent to the Gas Materials Specialist in Gas Engineering. The failed material or component should also be sent to the Gas Materials Specialist for failure analysis. If the failed item is large, heavy, difficult to ship, or to remove from the system, field personnel should contact the Gas Materials Specialist for further guidance. If it is decided the failed material or component need not be removed from the system, the field person should take a picture of the failed material or component and send it to the Gas Materials Specialist. A Gas Material Failure Report should be filled out for other non-leak material failures as well.

The Gas Materials Specialist will then take the steps below to determine to what extent the material is to be analyzed to determine the failure cause. The three levels of failure analysis include:

1. **Internal Analysis:** The Gas Materials Specialist will first examine the failure report and material to determine if the failure cause is readily identifiable as a known failure type, typically because it has been observed and confirmed previously by either a manufacturer or independent lab analysis. The Gas Materials Specialist may seek input from other gas materials experts including Gas Engineers, the Gas Pipeline Integrity Program Manager, or others to make this determination.

2. **Manufacturer Analysis:** If there is uncertainty in the failure cause using internal analysis, the material may be sent to the manufacturer for additional analysis. This is often done when suspected failure cause is a manufactured material defect or an installation error. The Gas Materials Specialist will confer with Gas Engineering before sending the material to the manufacturer.

3. **Independent Laboratory Analysis:** The Gas Engineering Manager and the Manager of Pipeline Integrity and Gas Compliance will collaborate on any request or recommendation for an independent laboratory analysis. The Gas Engineering Manager is responsible for the creation of the lab analysis specifications and for approving any laboratories to be utilized. An independent laboratory analysis may be sought for the following reasons:

   - The failure cause appears unique, i.e., the failure cause is not a known material defect, installation error, or other known failure cause.
   - The material is no longer being manufactured and it has a suspected manufacturing defect.
   - It is deemed prudent to acquire an independent analysis to confirm a failure cause, to dispute a failure cause, or to gain additional information.
   - Avista has been required to conduct an independent analysis.
   - The material is involved in or results in a major gas incident.

If it is determined by either internal or external analyses that the material failure was caused by an installation error, then an internal assessment should be performed when required per GESH, Section 17 – Gas Incident Field Investigation, or Gas Standards Manual, Specification 4.31, Operator Qualification. Once the failure cause has been determined by one of the three analysis methods above, the Gas Materials Specialist will document the failure cause and notify the Gas Pipeline Integrity Program Manager of the results. The Gas Pipeline Integrity Program Manager will record and trend material failures. Reports required by state or federal pipeline safety entities shall be submitted by the Gas Pipeline Program Integrity Manager and approved by the Manager of Pipeline Integrity and Gas Compliance.

The Gas Pipeline Integrity Program Manager works with the Gas Materials Specialist throughout this process to track and trend material failures as applicable in order to meet the requirements of Avista's DIMP and TIMP programs and to facilitate the submission of PHMSA Forms F7100.1-1 and/or F7100.2-1 as delineated in Gas Standards Manual, Specification 4.14, Recurring Reporting Requirements.

WAC 480-93-200 (6): In the state of Washington, when laboratory analysis is used to determine that a material or construction defect has resulted in an incident or hazardous condition, Avista must supply the WUTC a copy of the failure analysis report within 5 days of receiving it.

DOT Reportable Incidents

Incident assessments shall be conducted when a DOT Reportable incident occurs. The Pipeline Safety Engineer shall notify the Gas Quality Assurance (QA) Manager and the Safety Manager of such occurrences. The QA Manager and the Safety Manger will mutually determine who shall be responsible for coordinating and overseeing the process. These assessments shall be completed for incidents involving a federally defined incident per §191.3 as follows:

A release of gas from a pipeline and;

- A death; or
- Personal injury necessitating in-patient hospitalization; or
- Estimated property damage of the operator and/or others of $129,300 or more (excluding cost of gas lost); or
- The release of gas exceeding 3,000 MCF; or
- An event that is significant, in the judgment of Avista, even though it does not meet the criteria listed above.

Noticeable Trends (Multiple Occurrences)

Repeated events or noticeable trends of safety, material or other situations may be cause for an assessment to be completed. Some past examples of such “multiple occurrence” events have been:

- Valves installed and left in the closed position
- Failure to monitor downstream pressure when required

Gas Related Fires and/or Explosions

Oftentimes gas related fires and/or explosions will become DOT Reportable Incidents and require assessment as noted above. Lesser instances of such occurrences may merit assessment as well. The Senior Manager of Gas Operations and Gas Operations Managers are the gatekeepers to request an assessment of these “lesser” fires/explosions as applicable when they occur in their areas of responsibility.

Non-gas Related Fires and/or Explosions

In addition to gas related fires and explosions, there may be a need to assess non-gas related fires or explosions to provide lessons learned and to provide information for Avista stakeholders (Legal, Claims, External Communications, etc.) as applicable. The Senior Manager of Gas Operations and Gas Operations Managers are the gatekeepers to request an assessment of these situations as applicable when they occur in their areas of responsibility.

Employee Injury

This area of possible assessment is complicated as other entities such as Avista Safety, Occupational Health, Labor and Industries, OSHA, etc. may likely be involved. These incident assessments are facilitated by the Safety Department and in conjunction with the Gas Quality Assurance Department, where necessary, to address gas related considerations.

Third-Party Damages

Third-Party Damage is a situation where damage occurs to Avista facilities by entities other than Avista and its contractors. Third-Party Damage costs thousands of dollars of impact to Avista facilities every year. Typically, these types of assessments will be facilitated by the Underground Facility Damage Prevention Administrator, and consequently will usually fall outside the scope of this specification.

Pipeline Ruptures and/or Rupture Mitigation Valve (RMV) Closures (Transmission Facilities Only)

As discussed in §192.617 (c), if an incident on an inshore gas transmission pipeline involves the closure of a RMV, Avista must conduct a post-incident analysis of all the factors that may have impacted the release volume (of gas) and consequences of the incident and identify and implement operations and maintenance measures to prevent or minimize the consequences of a future incident. Until the time Avista installs RMVs, this portion of code is not applicable, however, once RMV(s) are installed, the assessment of any RMV closure will be conducted in accordance with §192.617 (c).

If the failure or incident on an onshore gas transmission pipeline involves the identification of a rupture following a notification of potential rupture, or the closure of an RMV, or the closure of an alternative equivalent technology, the operator of the pipeline must complete a summary of the post-failure or incident review required by paragraph (c) of this section within 90 days of the incident, and while the investigation is pending, conduct quarterly status reviews until the investigation is complete and a final post-incident summary is prepared. See *additional* detail at §192.617 (d).

Near Misses

Near misses are unplanned incidents or events that did not result in injury, illness, or damage, but had the potential to do so. Near misses provide an opportunity to conduct an assessment and identify and develop recommendations to prevent or minimize consequences of a future event. Process Safety near miss assessments are conducted by the Gas Quality Assurance Department and in conjunction with the Avista Safety Department when a potential employee serious injury or fatality is involved.

Other Management Directed Reasons

There is really no limit to the criteria or reasons for conducting an assessment. When in doubt, an assessment should be undertaken.

INCORPORATION AND COMMUNICATION OF LESSONS LEARNED

Procedures Updating (Includes Design, Construction, Testing, Maintenance, Operations, Emergency Response, Training, and Operator Qualification)

Once an assessment has been completed the recommended corrective actions identified by the assessment team are reviewed. Corrective actions focused on preventing or minimizing the consequences of a future incident are entered into the Avista Intelex safety data management system. The corrective actions within Intelex are assigned an owner and a due date to ensure items are tracked to completion. If the corrective actions identify gaps in the GSM or GESH, they are reviewed by the respective committee and changes incorporated, as appropriate. The lessons learned are communicated to pertinent employees.

5.10 GAS MAINTENANCE TIMEFRAMES AND MATRIX

SCOPE:

To define the various maintenance timeframes as required by state and federal regulations for gas pipeline systems.

REGULATORY REQUIREMENTS:

§192

WAC 480-93

The timeframes identified in this manual are defined as follows:

Definitions

Monthly – Means any time within the calendar month.

Annually – Means any time within the calendar year.

Calendar Year – Means twelve consecutive months beginning January 1 and ending December 31.

2-1/2 months – Means the same calendar date of the second consecutive month plus an additional 15 days.

4-1/2 months – Means the same calendar date of the fourth consecutive month plus an additional 15 days.

6 months – Means the same calendar date of the sixth consecutive month.

7-1/2 months – Means the same calendar date of the seventh consecutive month plus an additional 15 days.

15 months – Means the same calendar date of the fifteenth consecutive month.

3 years – Means the same calendar date of the third consecutive year.

39 months – Means the same calendar date of the thirty-ninth consecutive month.

5 years – Means the same calendar date of the fifth consecutive year.

63 months – Means the same calendar date of the sixty-third consecutive month.

10 years – Means the same calendar date of the tenth consecutive year.

For calendar dates that end on a weekend or holiday, the next business day shall be considered the timeframe end date.

The following pages include Gas Maintenance Matrix tables which outline the tasks and timeframes for each type of ongoing maintenance activity.

Category	Sub-Category	Maintenance Frequencies	DOT Ref.	Other References	GSM Ref.
Regulator Stations					
	Regulator Station Relief Inspection	Once Each Calendar Year, Not to Exceed 15 months	192.739 192.743		5.12
	Regulator Station Overhaul	Approx. 20% Per Year (Rebuild All In 5 Years)		Avista Internal Standard	5.12
	Master Meter Regulator Stations	Once Each Calendar Year, Not to Exceed 15 months	192.739 192.743		5.12
	Regulator Station, Relief Capacity Review	Once Each Calendar Year, Not to Exceed 15 months	192.743		5.12
	Gate Stations, Supplier's Relief Set Point Review	Once Each Calendar Year, Not to Exceed 15 months	192.743		5.12
	Regulator Stations Atmospheric Corrosion	Once Each Calendar Year, Not to Exceed 15 months	192.479 192.481	WAC 480-93-110	5.12
	Regulator Stations, operating on permanent bypass	Once Every 3 Years, Not to Exceed 39 months		Avista Internal Standard	5.12
	Portable Regulator Stations	Each time the station is placed into service		Avista Internal Standard	5.12
	Portable CNG Trailers	Once Each Calendar Year, Not to Exceed 15 Months		Avista Internal Standard	5.12
	Flexible Element and Boot Type Regulators (Overhaul)	Once Every 5 years		Avista Internal Standard	5.12
	Diaphragm Type Regulators and Pilot (Overhaul)	Once Every 10 years		Avista Internal Standard	5.12
Farm Taps					
	Farm Taps Atmospheric Corrosion	Once Every 3 Years, Not to Exceed 39 months	192.479 192.481	WAC 480-93-110	5.12

Category	Sub-Category	Maintenance Frequencies	DOT Ref	Other References	GSM Ref
Heaters					
	Regulator and Gate Stations, Line Heaters Leak Inspection	Monthly		Avista Internal Standard	5.22
	Regulator and Gate Stations, Line Heaters Operation	Monthly		Avista Internal Standard	5.22
	Regulator and Gate Stations, Line Heaters Water/Glycol Level	Monthly		Avista Internal Standard	5.22
	Regulator and Gate Stations, Line Heaters Water/Glycol Constituents	Sample Annually or Replace Every 3 Years		Avista Internal Standard	5.22
	Regulator and Gate Stations, Line Heaters Pilot Safety Test	Once Each Calendar Year, Not to Exceed 15 months	192.739		5.22
	Regulator and Gate Stations, Line Heaters High Temperature Shutdown Thermostat Test	Once Each Calendar Year, Not to Exceed 15 months	192.739		5.22
	Regulator and Gate Stations, Line Heaters Flame Arrestor Clean/Inspect	Once Each Calendar Year, Not to Exceed 15 months	192.739		5.22
	Regulator and Gate Stations, Line Heaters Heating Coil Inspection	Once Every 10 years		Avista Internal Standard	5.22
	Regulator Stations, Pilot Heaters Leak Inspection	Once Each Calendar Year, Not to Exceed 15 months	192.739		5.22
	Regulator Stations, Pilot Heaters Operation	Once Each Calendar Year, Not to Exceed 15 months	192.739		5.22
Valves					
	Emergency Valves (Distribution)	Once Each Calendar Year, Not to Exceed 15 months	192.747	WAC 480-93-100	5.13
	Emergency Valves (Transmission)	Once Each Calendar Year, Not to Exceed 15 months	192.745	WAC 480-93-100	5.13
	Emergency Curb Valves	Once Each Calendar Year Not to Exceed 15 months		WAC 480-93-100	5.13
	Blow Down Valves and Associated Appurtenances	Once Each Calendar Year, Not to Exceed 15 months	192.745 192.747	WAC 480-93-100	5.13
	Secondary Valves	Once Every 5 years Not to Exceed 63 months (Recommended)		Avista Internal Standard (Best Practice)	5.13

Category	*Sub-Category*	*Maintenance Frequencies*	*DOT Ref*	*Other References*	*GSM Ref*
Line Patrols					
	Transmission* Class 1 & 2 Locations	Once Each Calendar Year, Not to Exceed 15 months	192.705		5.15
	Transmission* Class1 & 2; Highway & RR Crossings	Twice Each Calendar Year Not to Exceed 7-1/2 months	192.705		5.15
	Transmission* Class 3 Locations	Twice Each Calendar Year Not to Exceed 7-1/2 months	192.705		5.15
	Transmission* Class 3; Highway & RR Crossings	Four Times Each Calendar Year Not to Exceed 4-1/2 months	192.705		5.15
	Transmission* Class 4 Locations (All)	Four Times Each Calendar Year Not to Exceed 4-1/2 months	192.705		5.15
	HP Distribution Pipelines	Once Each Calendar Year, Not to Exceed 15 months (Should occur as a Best Practice)	192.721		5.15
	Water Crossings and Other Pipelines where External Loading / Movement Likely	Four Times Each Calendar Year Not to Exceed 4-1/2 months	192.721		5.15
	Major River Crossings	Once Every 5 Years, Not to Exceed 63 months.	192.721		5.15
	Distribution Lines	Annually in Conjunction With 20% Leak Survey	192.721		5.15
	Line Markers	Once Every 5 years Not to Exceed 63 months	192.707	WAC 480-93-124	5.15
Cathodic					
	Annual Survey of Cathodic Protection Areas	Once Each Calendar Year, Not to Exceed 15 months	192.465		5.14
	Isolated Short Section Survey Main <100 ft. or Service Lines Protected isolated risers	10% Per Year (Entire System every ten years)	192.465		5.14
	Rectifiers	Six Times Each Calendar Year Not to Exceed 2-1/2 months	192.465		5.14
	Critical Bonds, Critical Diodes	Six Times Each Calendar Year Not to Exceed 2-1/2 months	192.465		5.14
	Other Bonds Other Diodes	Once Each Calendar Year, Not to Exceed 15 months	192.465		5.14
	Unprotected Pipelines	Within 1 yr. of Installation (90 Days, Washington)	192.465	WAC 480-93-110	5.14
	Casings with Steel Carrier Pipe	Once Each Calendar Year, Not to Exceed 15 months		WAC 480-93-115	5.14
	Shorted Casing (Confirm Short)	90 Days after initial determination of a possible short		WAC 480-93-110	5.14
	Atmospheric Corrosion, aboveground services	Once Every 5 Years, Not to Exceed 63 months	192.479 192.481	WAC 480-93-110	5.20
	Atmospheric Corrosion, aboveground pipelines other than services	Once Every 3 Years, Not to Exceed 39 months	192.479 192.481	WAC-480-93-110	5.20

* - May be different per Transmission Integrity Management Plan

Category	Sub-Category	Maintenance Frequencies	DOT Ref	Other References	GSMRef
Leak Survey					
	Business District	Once Each Calendar Year, Not to Exceed 15 months	192.723	WAC 480-93-188	5.11
	High Occupancy Structures High Occupancy Areas	Once Each Calendar Year, Not to Exceed 15 months		WAC 480-93-188	5.11
	20% Survey	20% Per Year, Complete System In 5-Year Period Not to Exceed 63 months	192.723		5.11
	Transmission Pipelines	Once Each Calendar Year, Not to Exceed 15 months	192.706		5.11
	Pipelines Operating greater than or equal to 250 psig	Once Each Calendar Year, Not to Exceed 15 months (Washington Only)		WAC 480-93-188	5.11
	<30% SMYS Transmission in Class 3 or 4 Location with no HCA's	Semi-annually as outlined Avista's Transmission Integrity Management Plan	192.935		5.11
	Non-Cathodically Protected Steel Pipe & Non-Cathodically Protected Isolated Risers	Twice Each Calendar Year Not to Exceed 7-1/2 months (Washington Only)		WAC 480-93-188	5.11
	Shorted Casings	Initially within 90 days of confirmed shorted condition and then 2 times each year not to exceed 7-1/2 months		WAC 480-93-110	5.11
	Road Resurfacing Jobs	Prior to Paving or resurfacing		WAC 480-93-188	5.11
	Underground Leak Residual Re-Check	Within 30 days of making repair		WAC 480-93-186	5.11
	Grade 2A Leak Response	Less than 30 days		Avista Internal Standard (Best Practice)	5.11
	Grade 2 and Grade 2A Re-Evaluation	Every 6 Months until cleared – Repair within 15 months		WAC 480-93-18601	5.11
	Grade 2 Repair	Within 1 Yr. Of Detection Not to Exceed 15 months		WAC 480-93-18601	5.11
	Grade 3 Re-Evaluation	Next Leak Survey or Not to Exceed 15 months		WAC 480-93-18601	5.11
	Program Self Audit	Every 3 Years (Washington Only)		WAC 480-93-188	5.11
	Third party damage	As needed		WAC 480-93-188	5.11
	In areas and times of unusual activity such as earthquake, floods, landslides, fires, etc.	As needed		WAC 480-93-188	5.11

Category	Sub-Category	Maintenance Frequencies	DOT Ref.	Other References	GSM Ref.
Odorization					
	Odorization Test	Monthly - All Test Points	192.625	WAC 480-93-015	5.23
	Test Point Review	Once Each Calendar Year		Avista Internal Standard	4.18
	Odorizer Maintenance	By type, per Specification 5.23		WAC 480-93-015	5.23
Vaults					
	Vault Maintenance	Once Each Calendar Year, Not to Exceed 15 Months	192.749		5.18
Meters					
	2 psig Residential	1 Time, After 180 Days		Avista Internal Standard	5.12
	2 psig Commercial	1 Time, After 180 Days		Avista Internal Standard	5.12
	5 psig Non-Industrial	1 Time, After 180 Days		Avista Internal Standard	5.12
	Industrial	Annually		Avista Internal Standard	5.12
Certifications					
	Welder Certification	Weld Retest Twice each calendar year Not to Exceed 7-1/2 months	192.227	WAC 480-93-080	3.22
	Plastic Certification	Re-Qualify, Annually Not to Exceed 15 months between qualifications	192.285	WAC 480-93-080	3.23
Damage Prevention					
	Public Awareness	As Necessary	192.616		4.13
Emergency Plan					
	Emergency Training	Annually	192.615		GESH 13
	Fire, Police, & Public Official Liaison	Periodically	192.615 192.616		GESH 13
O & M Manuals					
	O & M Manual Review	Once Each Calendar Year, Not to Exceed 15 months	192.605	WAC 480-93-180	1.4
	O & M Procedure Review	Periodically	192.605	WAC 480-93-180	1.4
Instruments					
	CGI Calibration	Monthly not to exceed 45 days and 12 times per year		WAC 480-93-188	5.19
	Leak Survey Equipment Calibrations	Per Manufacturer's recommendation		WAC 480-93-188	5.11
	Odorometer Calibration	Per Manufacturer's recommendation		WAC 480-93-015	4.18
	Pressure Gauges, Recorders and Calibration Standards	Once Each Calendar Year, Not to Exceed 15 months		WAC 480-93-170	5.21
	Meter Provers	Every 2nd Calendar Year		Avista Internal Standard	2.22
	Cathodic Instruments (Voltmeters, Electrodes, etc.)	Annually		WAC 480-93-110	5.14
Customer Notification					
	Notification to Customer of Responsibility for Buried Downstream Service	Letter to Customer Within 90 Days of Service	192.16		4.22

5.11 LEAK SURVEY

SCOPE:

To establish procedures to be followed in detecting, classifying, and reporting natural gas leakage in Avista's pipeline systems and facilities. Included in this section are leak survey types and methods, leak classification criteria, leak investigation and follow-up procedures, and recordkeeping requirements.

REGULATORY REQUIREMENTS:

§191.12, §192.503, §192.706, §192.709, §192.721, §192.723, §192.1009

WAC 480-93-110, 480-93-115, 480-93-175, 480-93-185, 480-93-186, 480-93-18601, 480-93-187, 480-93-188

CORRESPONDING STANDARDS:

Spec. 3.18, Pressure Testing
Spec. 3.44, Exposed Pipe Evaluation
Spec. 5.15, Pipeline Patrolling - Pipeline Markers
GESH Section 2, Leak Investigation
GESH Section 4, Emergency Procedures
GESH Section 17, Incident Investigation

LEAK SURVEY

General

Only properly trained and qualified employees and contractors shall perform leakage surveys, leak centering procedures, and calibration of leak detection equipment. Avista shall perform gas leak surveys in which a gas detection instrument is passed over the transmission and distribution pipelines, as well as other gas facilities. The frequencies and types of surveys are specified in this specification and shall conform to applicable regulatory codes. While performing leakage surveys, personnel will typically also perform distribution patrolling functions as noted in Specification 5.15, "Maintenance Frequencies". Specific detail on this accomplishment is covered in the Leak Survey Program Orientation Manual.

Relation of PPM, Percent Gas, and Percent LEL

PPM RELATION TABLE

PPM	% Gas	% LEL*
100	.01%	.2%
500	.05%	1%
1,000	.10%	2%
5,000	.5%	10%
7,500	.75%	15%
10,000	1%	20%
50,000	5%	100%
100,000	10%	
250,000	25%	

* - The percent LEL figures are based on 1% Gas being equal to 20% LEL for Avista gas

Gas Leak Detection Instruments

Instruments utilized to detect concentrations of natural gas shall be used according to manufacturer's instructions. These instructions shall be on-site when the equipment is in use for all surface gas detection surveys. Approved instruments utilized by Avista and its Contractors to detect concentrations of natural gas during leak surveys are as follows:

Detecto-Pak Infrared Detector (DP-IR) – The DP-IR is a detector that utilizes infrared controlled interference polarization spectrometry (CIPS). This translates to having a low-end sensitivity of 1 ppm that can auto-scale up to 100 percent gas by volume. The DP-IR is basically the combination of a "search" instrument and a CGI in one device that does not require external fuel gas. The DP-IR is also selective to methane only and thus prevents false positives that can be detected with other units. Additional features include a built-in self-test and zero function which helps assure the instrument is working properly. These self-tests are internally stored by the instrument which has sufficient memory to hold up to 2,000 logs. The DP-IR is currently the primary detector tool used by Contractor leak survey patrols (Other equivalent instruments may be used as technological advances are made).

Laser Methane Detector: A laser methane detector is an intrinsically safe detector that is capable of detecting methane from a remote distance and can be used to check for the presence of gas prior to entry or in hard to reach or not easily accessible areas. The instrument does not have to be within the gas plume because it uses laser technology known as Tunable Diode Laser Absorption Spectroscopy. As the laser passes through the gas plume, the methane absorbs a portion of the light, which the instrument then detects. There are many conditions that can impact a laser detector's reading; therefore, these instruments shall not be used to record gas concentration, grade, or classify a leak. The intent of these instruments is to provide other means of checking for the presence of gas.

> Remote Methane Leak Detector (RMLD): The RMLD is a type of laser methane detector that is often used when leak survey personnel cannot gain entry to a property, but can complete the leak survey from a remote distance. It is an intrinsically safe detector that is capable of detecting leaks from a remote distance (approximately 100 feet maximum) and consequently, it is possible to survey areas that are hard to reach or are not easily accessible (i.e., river/stream/canal crossings and secured facilities). The RMLD makes it possible to detect leaks along the sight line without needing to walk the full length of the service line. It is designed to be selective to detecting methane only and will not false alarm on other hydrocarbon gases. The RMLD has a built-in function to perform a self-test and calibration of the laser wavelength. The self-test feature should be used daily to ensure the instrument is operating properly. This tool is often used when leak survey personnel cannot gain entry to a property, but can complete the leak survey from a remote distance.
>
> Sensit Gas Trac LZ30: The Sensit Gas Trac LZ30 is an intrinsically safe compact laser methane detector that can be used to check for the presence of gas up to 100 feet away. The instrument can be used through windows, around door frames and in hard to reach areas such as high ceiling, soffit vents, crawl spaces. The instrument has adjustable visual, audible, and tactile alarms and features a target laser which is used to aim it in the desired direction. The instrument has a calibration cell inside its case.

Combustible Gas Indicator (CGI) – A Combustible Gas Indicator is an intrinsically safe leak detector that employs either a permeable membrane, catalytic or thermal filament to detect the presence of combustible gases. The Lower Explosive Limit (LEL) is measured using the membrane or filament. The membrane/filament is heated, combustible gases burn and then cool on the membrane/filament. The changes in temperature are then converted to a reading in percent Gas Range (0 to 100 percent gas in air) that is shown on a digital display.

Most modern CGI units are electronic and have a motorized pump system that is used to draw in an air sample. Older model CGIs used a hand aspirator pump for this purpose. CGI's are mainly used to obtain readings of combustible gases drawn from bar holes, inside structures, or in other confined areas. These detectors are not normally used in the system leak surveys due to the fact that bar holes would have to be drilled along all pipeline routes in order to effectively sample buried facilities. CGI's are, however, essential in centering leaks and obtaining accurate percentage gas in air readings.

Bascom Turner Gas Rover & Gas Explorer (ethane option) - The Gas RoverTM and Gas Explorer are both a type of CGI that can be used for handheld or mobile surveys and for responding to indoor or outdoor leak calls. The Gas-RoverTM and Gas Explorer are used to locate leaks, grade them, perform safety checks and, in the process, greatly reduce the number of bar-holes needed to be placed on the property. What makes both the Gas-RoverTM and Gas Explorer so versatile are their calibrated accuracy in the PPM range of gas, intrinsic safety, optional carbon monoxide and oxygen sensors, and their extensive and automatic data collection and storage.

The Bascom Turner Gas Rover and Explorer with ethane option allow the user to take an air sample from a site suspected to be non-pipeline gas, similar to the Sensit IRed (see below). These devices analyze the sample and give the user a result of ethane detected or not detected. Some units use a combination of the above technologies.

Note: There are some CGI detectors that do not indicate percentages of gas but simply have a visual or audible alarm. Detectors that have the capability of displaying percentage readings may be used to center leaks, determine the extent of underground leakage using bar holes, and to obtain readings in structures or other confined areas. Detectors without percentage indication shall not be used in leakage surveys or in centering and classifying leakage.

Sensit IRed Portable Infrared Ethane Detector (IRed): The Sensit IRed is designed to detect the presence of ethane in a methane sample. The IRed can detect 250 parts per billion (ppb) up to 500 ppm ethane. The IRed is used to determine if methane detected in the range of 50 to 2,400 ppm is of similar make-up to that of pipeline gas, which contains ethane or is naturally occurring methane from other sources such as organic decay. The IRed is not designed for high concentrations or determining actual ethane content from within a pipeline.

The IRed senses gas using Infrared Absorption Spectroscopy in combination with an electronic narrow band pass filter. This technology utilizes an infrared light source with an output that is changed when certain gases absorb the light output. The filter only allows specific light wavelengths to be monitored and measured. The concentration of gas is proportional to the amount of specific Infrared light absorbed and is displayed in parts per billion (ppb) or parts per million (ppm).

An IRed is currently housed with Avista's Leak Survey Administrator and others are dispersed in at least one construction office in each state. They are to be used when the result of a leak/odor investigation is inconclusive and foreign gas is suspected. Contact the Leak Survey Administrator if further information is required.

Other instruments historically utilized by Contractor and Avista personnel to detect concentrations of natural gas during leak surveys are as follows:

Flame Ionization Detector (F.I.) - This electronic instrument detects the presence of methane gas by measuring the ions produced in a hydrogen flame when gas is burned. The ions conduct electricity, which is in turn measured by the electronic circuitry in the instrument to produce a reading, normally in parts-per-million (ppm) of gas in air.

Most modern flame ionization detectors are capable of detecting concentrations of gas 1 ppm or less. Air samples are drawn into the detector by a pump. If the sample is diluted the readings may be inaccurate, thus it is not advisable to use this type of detector in wet or windy weather. Flame ionization detectors were at one time the primary instrument used in leak surveys to detect the presence of gas, however infrared and laser detectors have become the preferred technology for leak survey.

Maintenance of Instruments

Each instrument used for leak detection and evaluation shall be operated and maintained in accordance with the manufacturer's instructions. Instruments shall be calibrated monthly or in accordance with the manufacturer's instructions. Calibrations shall be performed on a regular schedule using certified test gases. Calibrations shall also be performed after any repairs or replacements of parts. Records of instrument calibrations shall either be affixed to the instrument and maintained in the local construction office or maintained within the Leak Survey Mobile Application as applicable. Dust filters on detectors shall be checked at least daily and more frequently if conditions are dusty. Filters should be changed or cleaned as necessary.

Batteries shall be checked daily and changed if the instrument will not zero or if it appears to not be functioning properly. Rechargeable batteries should be cycled periodically. Remove batteries if the unit is to be stored for a long period of time.

Detectors shall be checked for leakage in the sampling system before each use. Leaks shall be repaired (leaks in the sampling system can cause the sample to be diluted or may allow dirt to enter the instrument).

GAS LEAK SURVEY METHODS:

The following gas leakage survey methods and procedures shall be employed in locating leaks in gas piping systems and other related facilities:

Surface Gas Detection Survey

This survey involves continuous sampling of the atmosphere at or near surface level over buried or submerged gas pipelines and facilities with an instrument capable of detecting a concentration of at least 50 ppm or more of gas in air (gas detector) at any sampling point. For below ground facilities, any concentration of gas in air found in ppm shall be investigated, leak classified per this Specification and then documented for follow-up repair as necessary. Aboveground facilities are also to be checked with gas detectors during the survey and gas in air concentrations registering at or above 7,500 ppm shall be leak classified and then documented for follow-up repair. The exception is when an above ground leak is found on an indoor facility. The gas detector used in surface surveys shall be one of the approved leak detection instruments listed in the “Leak Detection Instruments” section of this Specification and one that is applicable. Sampling of the atmosphere over buried piping should be in accordance with the manufacturer’s specifications for the specific instrument, but not more than 2-inches above the ground surface as applicable.

Foot Survey - Survey of gas pipelines and facilities conducted on foot shall be conducted using an approved and applicable gas detector. The gas detector shall be passed over all portions of each main, service, and other facilities. In addition, the atmosphere shall be tested at accessible gas, electric, telephone, sewer, water, and other underground structures. The gas detector shall also be passed over cracks in pavement, in wall-to-wall paved areas, and over the cracks in the sidewalk. Building walls adjacent to the pipelines or facilities and other locations where there may be the possibility of migrating gas shall also be surveyed. Dead vegetation over the top of gas lines may be an indicator of an underground leak.

The individual performing the survey shall determine the locations of underground pipelines or facilities when necessary to accurately complete the survey. Pipelines and other facilities that are inaccessible by foot shall be surveyed using remote leak detection technology or other means of survey.

Mobile Survey - A vehicle mounted gas detector (one of the approved and applicable leak detection instruments listed in the "Leak Detection Instruments" section of this specification) may be used to perform the surface gas detection survey. This method may be used where it is practical in surveying long stretches of buried pipeline that are accessible to a vehicle. Care shall be exercised not to exceed speeds specified in manufacturer's instructions. Pipelines and other facilities that are inaccessible to vehicles shall be surveyed by foot or by boat.

Diver or Remote Submersible Survey (Underwater) – This is an underwater survey of gas pipelines using a qualified diver or a remote submersible vehicle with an inspection camera. This type of inspection is limited to very few locations in Avista's system where a foot survey is not possible due to the size and depth of the water crossing. During the survey the diver inspects for signs of leakage (bubbles) on the pipeline facility. Underwater surveys are the preferred method of survey for major river crossings and are completed in accordance with Specification 5.15, Pipeline Patrolling. Individuals performing the survey shall document conditions found and shall schedule required repairs or follow-up.

Boat Survey (Overwater) – This is a surface survey of gas pipelines using an approved and applicable gas detector. A boat survey is conducted overwater using an Avista approved procedure which shall take into account current/water flow, water depth and wind conditions. A bubble ascent calculation program is required to determine the appropriate size and location of the survey area. This type of survey is typically used to supplement a diver or submergible survey is limited to pipelines where a foot survey is not possible due to the size and depth of the water crossing. There are very few of these locations within Avista's system. During the survey, technicians should be performing a visual scan of the water surface over and downstream of the pipeline looking for bubbles and/or turbulence in the water that may indicate a leak. Individuals performing the survey shall document conditions found and shall schedule required repairs or follow-up.

Survey Documentation & Follow-up – Individuals performing surface gas detection surveys shall evaluate and classify any leaks found (refer to Classifying Leaks within this specification). Document the leaks using the Leak Survey Location Report, N-2511, or electronic record and forward the information as applicable for the scheduling of required repairs or follow-up.

***Survey Limitations* –** Leak survey should not be conducted during periods of high winds, rain, excessive soil moisture, wavy conditions or if the surface is sealed by ice or water as these conditions may prevent leaking gas from rising directly to the surface.

Soap/Bubble Leak Test

Soap/Bubble leak tests involve the application of a soap and water solution or other leak detection solution to exposed piping or facilities to determine the existence of a leak. The pipe or facilities to be tested should be reasonably clean and free of debris. The piping is then coated with the solution and monitored for signs of leakage (active bubbles).

This method is used to test exposed or aboveground portions of a system such as meter set assemblies, exposed piping at regulator stations, service valves, etc. It is also used to test any fittings or taps not included in a pressure test. Bubble tests are also used for detection of leaks on customer house (downstream) piping and equipment.

Soap/Bubble leak tests shall only be used as a supplement to the other methods of surface leak detection on exposed or above ground facilities in Avista's gas system. Employees performing soap/bubble leak tests shall document conditions found and shall schedule required repairs or follow-up.

Pressure Drop Test

This test is used to determine if an isolated segment of pipeline loses pressure due to a leak. The pipeline or facility must first be isolated in order to perform the test. Pressure drop tests conducted solely to determine if leakage exists should be performed at a pressure at least equal to operating pressure. Testing procedures shall conform to Specification 3.18, Pressure Testing.

Pressure drop tests have limited application in the scope of leak detection in a pipeline system. They will only establish whether a leak exists; the leak will then need to be located and evaluated. The employee performing pressure drop tests shall document conditions found and shall schedule required follow-up or repairs.

Detection of Other Combustible Gases

Most leak detection instruments will register a reading for other combustible gases even though they are calibrated for methane. In the case where leak indications are found that originate from a source other than natural gas, the employee performing the survey shall take prompt action at the time of discovery to protect life, property, and the environment. Employee shall notify the property owner or adult person on the premises that the leak indications were found, and that the source is other than natural gas. The customer shall be advised to contact the proper authorities for determination of the exact cause of the indication, and for correction of the problem. Examples of foreign sources of leak indications include gasoline vapors, sewer or marsh gases, propane vapors, etc.

WAC 480-93-185: In the state of Washington, the above procedures shall be followed, and the company shall take appropriate action regarding its own facilities to protect life and property. In addition, if an indication is found to originate from a foreign source and the situation is ongoing and potentially hazardous, the employee on site shall inform the property owner or the adult occupying the premises, and where appropriate, shall inform the police department, fire, department, or other appropriate governmental agency. If the property owner or an adult person occupying the premises is not available, the company must, within 24 hours of the leak investigation, send out a letter to the person occupying the premises explaining the results of the investigation. A copy of the letter must be kept for 5 years.

Can't Gain Entry / Can't Find

In the course of performing leak survey operations, survey technicians may encounter situations where they Can't Gain Entry (CGE) to the customer's property (because of a locked gate or an aggressive dog, etc.) or they Can't Find (CF) the gas meter to successfully complete the survey. Specific processes for CGE and CF follow up attempts by the survey contractor are detailed in the Leak Survey Orientation Manual (updated annually). If the follow up attempts required by the contractor are unsuccessful a service order is, then generated and Avista Gas Operations completes the survey.

LEAK SURVEY PLANS:

At the end of each year, the Leak Survey Program staff (in conjunction with the appropriate construction offices) shall determine the proposed leak survey program scope for the coming year.

Such proposals shall include:

- Mobile devices and/or maps showing the areas to be surveyed
- Methods of survey to be used
- Estimates of total footage of main, number of services, and/or total hours for the survey
- A brief summary and training plan for seasonal employees (as applicable)

Gas leakage surveys shall be conducted according to the following frequencies:

Annual Distribution System Surveys

Business Districts and Buildings of Public Assembly

Leak surveys shall be made once each calendar year not to exceed 15 months of all gas facilities within business districts and/or places of public congregation (high occupancy structures or areas). The surface survey shall be conducted using an approved gas detector in accordance with the procedures outlined in this specification.

Business District – An area where the public regularly congregates or where the majority of the buildings on either side of the street are regularly utilized for financial, commercial, industrial, religious, educational, health, or recreational purposes. Mains and gas facilities in the right-of-way adjoining a business district must also be included in the survey.

High Occupancy Structure (HOS) or High Occupancy Area (HOA) – A structure or area that is normally occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.) Structures and areas include churches, hospitals, schools, and may include assembly buildings, outdoor theaters, outdoor recreation areas, etc.

Where gas service lines exist, a survey shall be conducted at the building wall where the service enters the building. A permanent bar hole shall be drilled if deemed necessary by the employee conducting the survey.

If leakage is detected at the outside wall of a building, a survey shall be conducted on the inside of the building at points where migrating gas could be expected to enter and accumulate.

Service piping, service risers and valves, and the entire meter set assembly shall be checked with a leak detector or with a soapy solution.

Leaks detected shall be reported on an individually numbered leak survey report. Each underground leak detected shall also be noted on the appropriate map or electronic record, as applicable. Leak survey reports shall be forwarded to the local construction office for the appropriate action or follow- up.

Identifying High Occupancy Structures, High Occupancy Areas, and Business Districts

Annually, prior to the next leak survey season, the Leak Survey Program staff will conduct reviews using approved updates to the current season's map buffer layers to confirm any changes and make any necessary updates to the next season's survey maps. At this time the addition of high occupancy structures / areas are noted for inclusion on the annual survey program.

The records of this annual process are the red-lined maps / mobile device updates; no separate record of this review is required. Refer to Avista's Annual Map Update SOP for specific procedures on updating High Occupancy Structures, High Occupancy Areas, and Business Districts.

Transmission and Other High Pressure Pipelines

Transmission pipelines shall be leak surveyed once each calendar year not to exceed 15 months. The survey shall be conducted using an approved leak detection instrument. The exception is a transmission pipeline that meets the following criteria which shall be leak surveyed on a semi-annual basis:

- Pipelines and facilities that operate at less than 30 percent SMYS in a Class 3 or Class 4 location where no high consequence areas have been identified per Avista's Transmission Integrity Management Program

As a best practice starting in 2018, high pressure distribution pipelines in all states should be leak surveyed annually. The exception to this are pipelines and facilities, in Washington State, that operate at 250 psig, or above which must be surveyed as noted below.

<u>250+ psig Pipelines Washington Only</u>

Each leak detected shall be reported on an individually numbered leak survey report. Each underground leak detected shall also be noted on the appropriate map. Leak survey reports shall be forwarded to the local construction office for action and with Gas Engineering if the leak is on a High Pressure facility.

WAC 480-93-188: In the state of Washington pipelines <u>operating</u> at or above 250 psig must be leak surveyed at least once annually, but not to exceed 15 months between surveys.

5 Year Distribution System Survey

Residential areas shall be surveyed with an approved leak detection instrument so that the entire distribution system is surveyed in a 5-year period not to exceed 63 months. (Approximately 20 percent of the system shall be surveyed each calendar year).

Mains, services, meter set assemblies, and all other gas facilities shall be included in these surveys. Meter sets may be checked with a leak detector or tested with a soapy solution.

Each leak detected shall be reported on an individually numbered leak survey report. Each underground leak detected shall also be noted on the appropriate map or electronic record. Leak survey reports shall be forwarded to the local construction office for action or follow-up.

Special Surveys

The following special surveys are required in the state of Washington. Avista's operating districts in other states should also perform these special surveys as a best practice.

When special surveys are required, the respective operation's area representative shall notify the Leak Survey Program Administrator or Program Manager and provide delineation of the extent of the area requiring the special survey. Special surveys shall be surveyed with an approved leak detection instrument in the following instances:

- Prior to any paving or resurfacing, following street alterations or repairs where there are gas facilities under the area to be paved and when damage could have occurred to these facilities. This survey shall be completed to check the pipeline or facilities, and to check for gas at manholes and other street openings for the presence of natural gas. (Note: chip sealing of roadways is not considered paving or resurfacing to the extent that a special survey is required.)

- In areas of sewer, water, or other substructure construction adjacent to underground gas facilities where damage could have occurred to the gas pipelines.

- In areas with shifting or unstable soil conditions where active gas pipelines or facilities could be damaged or otherwise affected.

- In areas and at times of unusual activity, including, but not limited to, foreign construction, earthquake, flooding, explosions (including blasting operations), fires, or other natural disasters. (Note: In the case of an earthquake, first priority areas should be those where there has been noticeable damage to roadways, land distortion such as buckling and heaving of the ground, and places where there are known unstable soils and / or where landslides have occurred.)

- In cases where it is determined that additional survey methods are required to identify the source or location of a suspected gas leak or odor, or in cases where a company employee specifically requests a special survey.

- During pressure uprating procedures. Refer to Specification 4.17, Uprating.

- Shorted Casings – When a steel casing becomes electrically shorted to a steel gas pipeline and the short cannot be cleared in 90 days, a leak survey test shall be conducted within 90 days of discovery and at least 2 times annually thereafter, but not to exceed 7-1/2 months until the condition is corrected.

WAC 480-93-188 (3)(d): Where the gas system has non-cathodically protected steel piping. This survey must be conducted on all such segments of piping (including non-cathodically protected isolated risers) 2 times each calendar year not to exceed 7-1/2 months in the state of Washington.

- In Washington State where a steel gas pipeline is being lowered or moved (i.e., “roped”). Refer to Spec 3.12 – Pipe Installation Steel Mains for additional information. This should also be a best practice in Idaho and Oregon service areas.

WAC 480-93-175: Lowering or Moving Metallic Gas Pipelines – A leak survey must be conducted within 30 days from the date a steel pipeline has been moved or lowered that is 2 inches in diameter and smaller that operates at 60 psig or less and that did not have a study performed prior to moving in the State of Washington.

[For other states and facilities, this is a best management practice.]

- DIMP Identified Surveys – A special survey shall be conducted when a trend is identified through Avista’s Distribution Integrity Management Program, where a leakage survey has been identified as an additional action to minimize high risk facilities. The Pipeline Integrity Program Manager shall coordinate with the Leak Survey Program staff to determine the parameters of the survey.

CLASSIFYING LEAKS:

The following procedure establishes criteria by which leakage indications of natural gas may be classified. Each indication of gas leakage must be evaluated by the employee performing the survey. Evaluation includes establishing the area limits or perimeter of the leak, determining if immediate action is necessary to protect life, property, and the environment. Evaluation also includes assignment of a Grade or Class to the leak in conformance with this specification.

Leakage monitoring, classification, and repairs shall be based on the following factors:

- Potential or actual danger to the public or property
- The volume of escaping gas and the percentage readings on a Combustible Gas Indicator (or equivalent instrument).
- The area limits of the leak and the proximity to structures both above and below ground
- The possibility or presence of any type of channel or other means whereby gas may accumulate or migrate below ground
- Soil and surface conditions that may affect migration
- Proximity of the leakage to sources of ignition
- Public and media awareness, apprehension, and reaction to the leakage
- Earth movement, flooding, or other natural disaster where external stresses on pipelines or facilities may cause or accentuate leakage

When all the above factors have been considered, the employee performing the survey shall classify each leak using one of the following leak grades, thereby establishing the leak repair priority.

With regard to the following leak grade criteria, the definition of "reading" means a repeatable (sustained) representation on a combustible gas indicator or other similar instrument.

Grade 1 Leak

A Grade 1 leak is any leak that represents an existing or probable hazard to persons or property. It requires immediate repair or prompt continuous action until the conditions are no longer a hazard. Grade 1 leaks are responded to immediately by company personnel. Refer to "Re-classification of Leaks" subsection in this specification for further guidance on acceptable temporary repairs and if they meet the requirements of "prompt continuous action" noted here.

Examples of Grade 1 Leak Situations:

1. Any leak which, in the judgment of personnel on the scene, is regarded as an immediate hazard to life, property, or the environment
2. Escaping gas that can be seen, felt, or heard which is in a location where it may endanger the general public, property, or the environment
3. Escaping gas that has ignited
4. Any indication of gas which has migrated into or under a building or tunnel
5. Any reading at the outside wall of a building where the gas could potentially migrate to the inside wall of a building
6. Any reading of 80 percent LEL or greater in a confined space
7. Any reading of 80 percent LEL or greater in small substructures not associated with gas facilities where the gas could potentially migrate to the outside wall of a building
8. Any leaks involving construction damage to our pipelines or facilities
9. Any leaks where the police, fire department, other governmental authority, or media has responded and Avista has been notified as such

Note: The Avista First Responder can leave once the investigation is complete, the scene is safe, and a crew is on location making repairs.

Action to Be Taken:

Immediate and prompt action until the leak is considered non-hazardous may include one or more of the following:

A. Implementation of the company Emergency Operating Plan (EOP)
B. Evacuation of the premises involved, and any adjacent structures as needed
C. Blocking off an area
D. Re-routing traffic (vehicle or pedestrian)
E. Removal of all sources of ignition
F. Venting of the leak
G. Stopping the flow of gas by closing valves or by other means
H. Notifying the police and fire departments
I. After making safe, repair the leak

Grade 2A Leak

A Grade 2A leak is assigned only by Avista's Leak Survey Contractor and defined as**:** Any leak that is recognized as being non-hazardous at the time of detection, but that justifies scheduled repair based on probable future hazard and is in a location that would benefit from a response sooner than the standard Grade 2 timeframe.

Examples of Grade 2A Leak Situations:

1. Any leak discovered greater than 5 feet from a building foundation, but may have the potential to migrate to the building foundation
2. Any leak discovered in a high use hardscape area, such as a street intersection
3. Any readings between 20 percent and 80 percent LEL in a confined space

Grade 2 Leak

A Grade 2 leak is any leak that is recognized as being non-hazardous at the time of detection but justifies a scheduled repair based on probable future hazard. Underground leaks that are classified as Grade 2 by the individual performing leak surveys shall be followed up with a subsurface survey (pinpointing of the leak) and a verification of the grading by obtaining percentage reads with a Combustible Gas Indicator.

Examples of Grade 2 Leak Situations:

Leaks requiring action prior to ground freezing or other adverse changes in venting conditions (any leak that could potentially migrate to the outside wall of a building under frozen or adverse soil conditions).

Leaks requiring action within 6 months include the following:

1. Any reading of 40 percent LEL or greater under a sidewalk in a wall to wall paved area that could potentially migrate to the outside wall of a building
2. Any reading of 100 percent LEL or greater under a street in a wall to wall paved area that would probably migrate to the outside wall of a building
3. Any reading less than 80 percent LEL in small substructures not associated with gas where gas would probably migrate creating a probable future hazard
4. Any reading between 20 percent and 80 percent LEL in a confined space (See also "Grade 2A Leak" earlier in this specification. Leak Survey Contractor shall report these as a Grade 2A.)
5. Any reading on a pipeline operating at 30 percent SMYS or greater in Class 3 or 4 locations.
6. Any leak which in the judgment of operating personnel at the scene is of sufficient magnitude to justify scheduled repair

It should be recognized that Grade 2 leaks will vary greatly in degree of potential hazard. Some Grade 2 leaks, which when evaluated by the above criteria, may justify scheduled repair within the next 5 working days. Others may justify repair within 30 days. These situations should be brought to the attention of the individual responsible for scheduling leakage repair.

Action to Be Taken:

Grade 2 leaks shall be reevaluated at least once every 6 months until cleared. The frequency of re-evaluation should be determined by the location and magnitude of the leakage condition. Leaks should be repaired or cleared within one year, not to exceed 15 months, from the date reported. If a Grade 2 leak occurs in a segment of pipeline due for replacement, an additional 6 months may be added to the 15 months maximum time for repair. The following factors shall be considered in assigning a priority of repair: Amount and migration of gas, proximity to buildings and subsurface structures, extent of any paving, soil type and conditions (frost caps, moisture, natural venting, etc.).

In addition to the above requirements, the judgment of experienced field personnel shall be enlisted in determining the scheduling of repairs on Grade 2 leaks. These leaks shall be repaired under a time schedule that provides safety to the public, while remaining practical to company operations.

Grade 3 Leak

A Grade 3 leak is any leak that is non-hazardous at the time of detection and can reasonably be expected to remain non-hazardous. Underground leaks coded Grade 3 by the individual performing leak survey shall be followed up with a subsurface survey (pinpointing of the leak) and a verification of the classification by obtaining percentage reads with a Combustible Gas Indicator.

Examples of Grade 3 Leak Situations:

1. Any reading of less than 80 percent LEL in small gas associated substructures such as small meter boxes or gas valve boxes
2. Any reading under a street in areas without wall to wall paving where it is unlikely the gas could migrate to the outside wall of a building
3. Any reading of less than 20 percent LEL in a confined space

Action to Be Taken:

Grade 3 leaks shall be re-evaluated during the next scheduled leak survey or within 15 months of the reporting date, whichever occurs first, until the leak is re-classified or repaired.

Aboveground Outside Leak Classification

If a leak is found on aboveground facilities it should be graded in accordance with the following:

Grade 1 – A Grade 1 leak is any leak that represents an existing or probable hazard to persons or property – (Hazardous.) Refer to Grade 1 Leak subsection in this specification.

Grade 2 – Any leak that is recognized as being non-hazardous at the time of detection, but that justifies scheduled repair based on probable future hazard. Any leak registering on a CGI (percent gas mode) 5 percent or greater gas in air.

Grade 3 – Any leak that is non-hazardous at the time of detection and can reasonably be expected to remain non-hazardous. Any leak registering on a CGI (percent gas mode) 0.75 to 4.99 percent gas in air.

Note: A leak found on aboveground facilities does not require documentation and classification until it can be detected at a minimum of 7,500 ppm gas in air.

Aboveground Inside Leak Classification

Any inside leak on Avista piping should be treated as a Grade 1 leak by Avista's Leak Survey Contractor for subsequent evaluation and grading by an Avista Gas Serviceman. The Avista First Responder should evaluate the potential hazard posed by the leak, and if appropriate in their judgment, may downgrade the leak one time to a Grade 2 or a Grade 3.

Underground Leak Determination

The presence or absence of underground leakage shall be determined by performing a bar hole survey utilizing a CGI unit in "percent gas mode" **or** a ppm survey utilizing approved leak detection instrument in "ppm mode" that is capable of detecting a concentration of 50 ppm or less. Should any concentration in the "ppm mode" be found, a bar hole survey using a CGI in the "percent gas mode" is required to be used to pinpoint and grade the leak. For a ppm survey, describe the area surveyed (refer to GESH 2, Leak and Odor Investigation, "Investigation at Aboveground Avista Facilities" for examples of descriptions) and document the results found. For a bar hole survey, the location and results of each bar hole shall be documented. Checks shall be made at the following locations to determine the extent of the leakage:

- The point of entry of all underground utilities to a building or structure (gas service riser, water service, sewer, conduits, etc.)
- At cracks in exterior basement walls and around the perimeter of the building foundation.
- Over the service line and out to the main, as necessary.
- At street openings such as curb boxes, drains, vaults, manholes, etc. in the immediate area.
- In the interior atmosphere of the basement of any building or structure involved in the investigation.
- At any other location where, natural gas may accumulate or migrate.

Underground Leak Investigation

<u>The Avista First Responder / Leak Survey Technician (as applicable) shall investigate for the presence of underground leakage by taking underground samples, using bar hole sampling in percent gas mode, when any of the following conditions exist:</u>

- When leakage on a meter set assembly or outside customer house piping is repaired and gas odors persist.
- When an Avista-side or customer-side odor investigation is <u>intermittent or inconclusive</u> as to the source of the odor.
- When it is determined that we have previously responded to a leak or odor call at the same premise location within the past 30 days.
- When a fire department (or other emergency responder) has requested our response to check our gas facilities (example: close a meter due to fire, continue a leak investigation begun by the fire department, etc.). Refer to GESH Section 17, Gas Incident Field Investigation.
- In all cases of failures of gas facilities or when our gas facilities are involved in fires or explosions. Refer to GESH Section 17, Gas Incident Field Investigation.
- In any other situation where it is suspected that natural gas may be leaking or migrating underground.
- When there is suspected damage beyond a break in a main or the possibility of multiple leaks.
- When a service line has been pulled, broken, or damaged (even without apparent leakage) by a third party excavation. (Refer to "Service Line Leak Survey", later in this section for further details).

Note: Bar holes over 12-inches in depth require notification to the One Call Center.

Survey Limitations: To determine which type of survey to use above, consideration must be given to limitations such as frost, rain, high winds, surface sealed by ice/water, paving, concrete, or other issues that would prevent an effective survey.

Pinpointing / Centering

Pinpointing is the process of tracing a detected gas leak source. It should follow an orderly systematic process to minimize excavation. When underground leakage is detected, a ppm-only survey is not sufficient. A percent gas-in-air survey must be combined with a bar hole survey. The following procedure for centering or pinpointing the leak shall be followed.

A subsurface survey or leak centering procedure shall be conducted by taking samples with a combustible gas indicator in a series of available openings (sewer manholes, electric or telephone substructures, etc.) or bar holes over or adjacent to the pipeline or facility. The location of the gas facility and its proximity to buildings and other structures should be considered when determining the spacing of sample points. Spacing of sample points along the main or service will depend on soil and surface conditions but should never be more than 20 feet apart. Where a pipeline passes under a paved area, samples should be taken at the entrance and exit points of the paved area. In areas of extensive paving, consideration shall be given to drilling permanent test holes.

When conducting the survey, bar holes should penetrate to approximately the same depth. Readings taken at the same depth will enable a meaningful comparison between samples. The reading should be taken at the bottom of the test hole. Care shall be taken not to aspirate water into the instrument. Combustible gas indicator probes shall be equipped with a device to prevent the drawing in of fluids. Refer to Specification 5.19 on how to measure the concentration of methane in a bar hole or other confined area.

When taking each sample reading, the employee performing the survey shall use the most sensitive scale on the instrument. Any indications shall be investigated to determine the source of the gas. Care should be taken when probing, especially around plastic pipe.

Sample patterns should include points as close as possible to the main or pipeline, and adjacent to service taps, known branch connections, Dresser fittings, or other compression couplings. Risers and buried piping near building walls should also be sampled.

Samples shall continue to be taken until the area limit of the leak is determined, and until the readings have been sufficiently analyzed so that the suspected center or source of the leak is determined. Locations with the highest readings will normally indicate that they are closest to the center of the leak; however, other factors may preclude this. In instances where readings of 100 percent gas are obtained in several bar holes, it may be necessary to use an ejector aerator to purge each bar hole. In no case should air ever be injected into a bar hole, as this could result in the gas being driven through the soil into a structure. Remember when analyzing readings that there is a potential for multiple leaks.

The locations and percentage of gas in air readings obtained with the combustible gas indicator shall be documented on the appropriate gas operating order. Indicate the approximate locations where the samples were taken and the corresponding gas-in-air percentage readings in relation to the involved structure or other physical landmarks in the area.

Venting Underground Leakage

All underground leaks shall be vented to the atmosphere as soon as possible. Underground samples shall be taken at practical time intervals to determine the extent of migration during repairs and to determine when such concentrations have reached a safe level. If excavations cannot be left open, for example, due to traffic, the excavation should be filled with a granular material such as gravel until the gas is completely vented.

Gas Present in Sewer or Duct System

If gas is found to be migrating to or accumulating in sewer or other duct systems, the Avista First Responder shall make a complete survey of the affected system to determine the area limits of the leakage. All buildings or structures served by the system or adjacent to it shall also be checked for the migration and/or accumulation of natural gas. Emergency procedures shall be followed to protect people and property in the event that gas is found to be migrating in sewer or duct systems. Manhole covers and other lids should also be removed, and the open manhole barricaded to aid in venting.

Underground leaks shall be pinpointed and classified per the Leak Classification criteria noted in this Specification. Leaks classified Grade 1 shall be repaired immediately. Grade 2 and 3 leaks shall be scheduled for repair per the judgment of trained, qualified field persons on the scene. **In all cases, leakage that is found to be migrating to a building foundation, accumulating in an enclosed area or tunnel, or that may pose a hazard to the public or property shall be repaired immediately.**

Gas Control Room Notification

The Gas Control Room shall be notified at (509) 495-4859 or via radio as to the conditions found and whether a construction crew or other assistance is needed to make permanent repairs.

Remaining-on-the-Job

In all cases, the Avista First Responder shall remain on the job site until the situation is safe and poses no hazard to the public or until relieved by a supervisor or other trained and qualified gas employee.

UNDERGROUND LEAK REPAIR

Leak Repair and Residual Gas Checks

After any leak is repaired it shall be checked for residual gas while the excavation is still open by a person qualified in Avista Side Leak Investigation. The perimeter of the leak area shall be bar holed and checked with a combustible gas indicator in percent gas mode to determine if repairs were adequate and if there is any migration from a secondary leak. A minimum of four (4) bar hole readings shall be taken at equally spaced points at the perimeter of the excavation or from within the bell hole prior to backfill to fulfill this requirement. If readings indicate the presence of gas, the perimeter shall be expanded, and additional bar hole readings taken until the extent of the leak is found and documented down to less than 0.05 percent gas in air. If the discovery of gas is determined to be a second leak, a new order shall be established by contacting the Avista Call Center by calling 800-227-9187. Bar hole locations shall be mapped as appropriate.

EXCEPTION: When a leak is found in a valve box and the leak is repaired by performing maintenance on the valve, a reading from a combustible gas indicator shall be taken near the bottom of the valve box after the repair is made. If the reading is zero percent gas in air, bar holes are not required, and the reading shall be documented on the order. If the reading indicates the presence of gas, bar holes shall be taken around the perimeter of the leak area as described above.

Repairs to damaged service lines require additional leak survey actions. Refer to the "Service Line Leak Survey" subsection below.

Whenever a pipeline is exposed, whether steel or PE, an Exposed Pipe Inspection Report form (Form N-2534) shall be completed. Further detail regarding the use of the Exposed Pipe Inspection Report form is detailed in Specification 3.44, Exposed Pipe Evaluation.

Pressure test information is required if a section of pipe is replaced. It can either be tested in the field or by using pretested pipe. Refer to Specification 3.18, Pressure Testing.

When exposed, underground Dresser-style or other steel mechanical compression fittings shall be cut out or canned (barreled). A Cathodic Protection Technician shall be contacted to verify that the fitting is not being used as an isolation point. Cutting out or barreling may inadvertently create a problem between two separated cathodic protection systems so additional steps may be necessary before removing or barreling the fitting.

Pressure Testing Replaced Segments

Pressure test information is required if a section of pipe is replaced. It can either be tested in the field or by using pretested pipe. Refer to Specification 3.18, Pressure Testing, for further information.

Reinstating a Damaged Service Line

A service line that has been is broken, pulled, or damaged resulting in the interruption of gas supply to the customer shall be pressure tested from the break back to the meter location for the same duration and to the pressure required for a new service. See Specification 3.18, Pressure Testing, "Reinstating Service" for further information.

Service Line Leak Survey

When a service line has sustained excavation damage (even without apparent leakage) by a third party excavation, a barhole survey or a ppm survey shall be performed from the point of the damage to the service tie-in at the main or after the branch. Should any concentration in the ppm mode be found, a bar hole survey using a CGI in the percent gas mode is required to pinpoint and grade the leak. Broken tracer wires and nicked coatings do not require the leak survey to occur.

Follow-up Inspections for Residual Gas

In the case of a repaired underground leak where residual gas remains below ground within 1-foot of a building wall, the employee shall remain on scene to actively monitor and lower the degree of hazard until the gas concentration within 1 foot of the wall is <1 percent gas-in-air and falling as determined by 3 successive reads, no sooner than 20 minutes apart. (Reference the GESH, Sections 2 and 4.) The employee shall find the perimeter of the readings by bar holing until less than 0.05 percent gas-in-air is detected.

In cases away from structures, where there is residual gas in the ground after a repair, regardless of the grade of the leak, a follow-up inspection with an approved leak survey instrument or CGI, in the percent gas mode, shall be made as soon as practical, but in no case later than 30 days after the repair. The repair shall continue to be rechecked until a reading of less than 0.05 percent gas-in-air is obtained by taking bar hole readings and the leak repair order is closed. Bar hole readings should be taken as close as possible to the previous reading locations.

If any residual gas exists, the employee shall find the perimeter of the readings by bar holing until less than 0.05 percent gas-in-air is detected, to assure a new leak source from outside the original site is not occurring**. If a new leak is discovered, this must be treated as a new investigation and must be documented separately on a new leak order**. This will allow for proper documentation of the cause of the new leak and for filling out an Exposed Pipe Inspection Report as applicable. Bar hole locations shall be mapped as appropriate.

Large amounts of gas that have saturated the ground may take additional time to completely vent. Successive readings should indicate a consistent drop in gas-in-air concentrations over time. If a reading of less than 0.05 percent reading is not obtained after a reasonable time allowance for venting, the leak repair shall be excavated and visually examined for defects, and the adjoining pipeline checked for additional leakage.

If a defect in the leak repair is found or if additional leakage is indicated, the leak shall be graded, and repairs made.

Re-Classification of Leaks

Leaks shall be re-inspected using the same criteria and guidelines used to classify leaks when they are first detected. A Grade 1 or 2 leak can only be downgraded once to a Grade 3 leak without a physical repair. After a leak has been downgraded once, the maximum repair time for that leak is 21 months from the date of the downgrade. (<u>The downgrading of a Grade 1 leak classification to a Grade 2 or Grade 3 classification should only occur when the leak has been misclassified.)</u>

Maximum effort should be implemented to fix Grade 1 leaks when discovered. A temporary repair, however, may be authorized in cases where an immediate repair is not feasible. A Grade 1 leak that has had temporary repair action taken so that it is no longer hazardous may be left to fix when conditions allow if after three consecutive reads, 20 minutes apart, the reads demonstrate that the gas in air levels are not rising to hazardous levels. A Grade 1 leak that has had temporary repair and is no longer hazardous, should not be left longer than one week in this state without the approval of the operations manager and the Manager of Gas Engineering. Combustible Gas Indicator readings in percent gas mode via bar hole shall be taken DAILY to ensure gas levels are staying non-hazardous until the final repair is complete. These leaks will remain classified as Grade 1 leaks.

Self-Audits

Audits shall be performed as frequently as necessary, but in any case, at intervals not exceeding three years to determine the following as discussed in WAC 480-93-188(6). (These self-audits are required in Washington and are a best management practice in other states.)

- That the leak survey schedule is commensurate with the requirements in the applicable State and Federal codes;
- That the survey program is effective and that a consistent evaluation of leaks is being made throughout the system;
- That required repairs and follow-ups are being made within the time limits specified;
- That leak repairs are effective; and
- That the records being kept are adequate and complete.

Self-Audit Records

To align with the Distribution Integrity Management Program (DIMP), Leak Survey Self-Audit records shall be retained for 10 years.

MAINTENANCE FREQUENCIES:

Avista leak survey programs shall be performed according to the following schedules:

Type of Survey	Frequency
Business Districts and High Occupancy Structures / Areas	Once each calendar year, not to exceed 15 months
Residential Areas 5 Year Survey (20 percent Survey)	5 Years, not to exceed 63 months 20 percent of system each calendar year
Non-Cathodically Protected Isolated Risers	Twice each calendar year, not to exceed 7-1/2 months *(Washington only)*
Other Non-Cathodically Protected Steel Pipelines	Twice each calendar year, not to exceed 7-1/2 months *(Washington only)*
Shorted Steel Casing	Within 90 days from date of discovery then twice each calendar year not to exceed 7-1/2 months)
Transmission Lines	Once each calendar year, not to exceed 15 months
<30 percent SMYS Transmission Lines in Class 3 or 4 Location with No HCA's	Semi-annually as outlined in IMP Plan
Paving and Utility Construction Jobs	Prior to paving, after construction is completed
High Pressure Pipelines (Oregon, Idaho, and Washington < 250 psig)	Annually (best practice)
High Pressure Pipelines Operating >=250 psig	Once each calendar year, not to exceed 15 months *(Washington Only but a best practice in Idaho and Oregon))*
Lowering or Moving of Steel Pipe =≤ 2" & ≤ 60 psig, No roping calculations needed	Within 30 days of moving pipe *(Washington Only but a best practice in Idaho and Oregon)*
Type of Repair or Follow-Up	**Frequency**
Grade 1 Leak Repair	Immediate Response - Continuous Action Until Non-Hazardous
Grade 2A Leak (Recommended Response)	Less than 30 days
Grade 2 Leak Repair	Within 1 year, not to exceed 15 months
Grade 2 and 2A Re-Evaluation	At least once every 6 months until cleared (repair within 15 months)
Grade 3 Leak Repair	Continuous annual or survey monitoring until repaired or re-classified
Grade 3 Re-Evaluation	Once each calendar year, not to exceed 15 months until cleared
Underground Leak Repair Follow-Up (regardless of the grade)	Immediately after repair, and not later than 30 days after where residual gas is present
Self-Audit of Leak Survey Program	Not to exceed 3 years. *(Washington Only)*

Recordkeeping

Records and maps of leak surveys performed shall be retained for the life of the facilities.

Each leak survey performed and/or leak discovered shall be recorded on an individually numbered leak survey report. The report shall be filled out as completely as possible and shall indicate the following information:

LEAK SURVEY FORMS:

Special information required for leak surveys performed:
- Date of survey and a description of the area surveyed (include maps and any logs kept)
- Survey method (DP-IR, RMLD, IRED, CGI, etc. including instrument number) and name of person(s) performing the survey
- Results of the survey, including the number of services checked, the footages of mains surveyed, number of leaks found and locations of leaks, the leak grades as they were classified by the surveyor, as well as references to individual reported leaks and map reference numbers

Special information required for leaks discovered:
- Address and complete location of the leakage (include drawing as necessary)
- Leak Survey Map reference number
- Time and date leak found
- Leak classification grade and percentage gas-in-air reading
- Leak data such as type of detector and instrument identification number, probable source of leakage, soil type, surface conditions, pipe size and type, vegetation damage, etc.

Special information required for leaks repaired:
- Bar holing information, if required
- Leak detection instrument identification number and percent of gas in each bar hole
- Leak cause* (Refer to end of this specification for definitions of causes)
- Component leaking
- System facility (main, service, valve, etc.)
- Pipe size and material type
- Location
- Repair Date
- Exposed Piping Inspection Report
- Pressure test info (tested in the field or pretested pipe)
- Repair materials
- Post-repair perimeter of excavation readings with type of approved leak detection instrument and ID number.

Leak repair work orders shall be retained with the leak survey report and the report shall be noted as to the disposition of the repairs and/or follow-ups. (When exposing pipe, an Exposed Piping Inspection Report Form (Form N-2534) shall be completed. Reference Specification 3.44, Exposed Pipe Evaluation, for further guidance.)

Special information required for rechecks:
- Date of the recheck.
- Percentage gas-in-air readings found for each bar hole location.
- Type of combustible gas indicator used and ID number.
    - o If additional readings of gas are found, additional follow up and documentation is required until the residual gas is cleared.

Closing Leak Reports

A leak report shall be considered closed when one or more of the following conditions have been established:

- The cause of the leak report has been corrected by the completion of necessary repairs, or
- Where evidence indicates that materials other than natural gas caused the leak report, and this information has been directed to the appropriate parties for action, or
- When required, a follow-up inspection has been conducted which shows the absence of natural gas

Blowing Gas and Odor Calls

For information on recording the appropriate information on blowing gas and odor calls refer to the Gas Emergency and Service Handbook, Section 2.

Leak Incident Reporting

When an individual makes a determination that a leak condition indicates a hazardous or potentially hazardous situation, **the individual shall immediately notify the Call Center by calling 800-227-9187** and request assistance as needed. In the case of major construction damage or any situation that is indicated as reportable in GESH Section 13, Emergency Planning, Training and Incident Notification, the Gas Controller shall immediately notify the following persons or departments:

- Emergency services (as necessary)
- Appropriate crews or servicemen to control the situation and effect repairs
- Claims Department
- On-call construction supervisor
- On-call Gas Engineer
- Applicable operations manager
- Corporate Communications

The On-Call Gas Engineer shall evaluate the situation and determine if a telephonic report to the appropriate agency is required and shall make the report within the specified time limits. Field employees and the Gas Control Room shall provide the necessary information to complete the required reports as soon as such information is known. Reports and related information shall be recorded on the appropriate forms and retained in Gas Engineering. In addition, written follow-up reports shall be completed by the On-Call Gas Engineer and forwarded to the appropriate agency within the specified time limits.

LEAK FAILURE CAUSE DEFINITIONS

The following are definitions and examples for leak failure causes:

CORROSION: Leak resulting from a hole in the pipe or other component that galvanic, bacterial, chemical, stray current, or other corrosive action causes (corrosion is not limited to a hole in the pipe).

- Pitting
- Dog urine
- Leaks from components that broke due to corrosion such as bolts

NATURAL FORCES: Leaks not attributable to humans such as:

- Earth movements - earthquakes, landslides, subsidence
- Lightning
- Heavy rains/floods - washouts, flotation, mudslide, scouring
- Temperature - frost heave, frozen components, snow related (Refer to snow removal under “other outside force damage”)

- High winds or similar natural causes
- Leaks attributable to animals (gophers, moles, etc.)

EXCAVATION: Leak resulting from excavation damage caused by:
- Earth moving or other equipment, tools, or vehicles
- Operator's personnel or contractor
- People not associated with the operator
- Unknown previous damage by excavators such as backhoe damage, stakes, ground rods, etc.
- Ground settlement due to excavation disturbance of original compacted backfill

OTHER OUTSIDE FORCE DAMAGE: Include leaks attributed to humans:
- Fire or explosion
- Deliberate or willful acts, such as vandalism
- Vehicular or other machinery (i.e., lawn mower) damage to aboveground facilities
- Animals chained to meter set assembly (MSA)
- Snow removal (shovel, plowing, roof clearing)
- Electrical arcing

MATERIAL*:
Material - include leaks resulting from a defect in the pipe material or component due to faulty manufacturing procedures.
- Any type of material failure (i.e., cracks/breaks) in plastic pipe or the body of plastic fittings (Aldyl A service tee crack in tower, cracked service tee caps, rock impingement)
- Failure in steel pipe or the body of steel fittings (not including corrosion)
- Failure in longitudinal weld or seam
- Deterioration of original sound material
- Pipe failure due to bending stress

Any leak marked as a material failure shall also have a Gas Material Failure Report filled out and sent to the Gas Materials Specialist in Gas Engineering along with the failed component per Specification 4.11, Continuing Surveillance.

WELDS/JOINTS - This includes leaks due to:
- Faulty wrinkle bends
- Faulty field welds
- Plastic joints
- Mechanical fittings (Refer to further guidance at end of this section for Hazardous Mechanical Fitting Failures)
- Underground leaks on threaded fittings that cannot be tightened

WAC 480-93-200 (6): In the state of Washington, when laboratory analysis is used to determine that a material or construction defect has resulted in an incident or hazardous condition, Avista must supply the WUTC a copy of the failure analysis report within 5 days of receiving it.

EQUIPMENT: Leaks resulting from:
- Failure or malfunction of fittings and equipment with internal components
    - Malfunction of regulator/relief equipment (weeping regulators /relieving regulators/debris in regulators), remote control valves, instrumentation
    - Seal failures on gaskets, O-rings, seal/pump packing, or similar leaks (fittings with O-rings in caps)

- Stripped or cracked threads on nipples, valves, or other threaded fittings
- ERT leaking/degradation

OPERATION: Leaks resulting from:

- Inadequate procedures or safety practices, or
- Failure to follow correct procedures, or other operator error
    - o Stab fittings not chamfered correctly or inadequate stab depth
    - o Debris found in cap of fitting
- MSA settlement failures
- Damage sustained in transportation to the construction or fabrication site
- Failure of original sound material from force applied during construction that caused a:
    - o Dent
    - o Gouge
    - o Other defect that eventually resulted in a leak

LOOSE / NEEDS GREASE: Leaks fixed by:

- Tightening of fitting (MSA fittings, service tee caps, stopper fitting caps)
- Applying new pipe dope
- Lubrication such as valves both underground and aboveground

OTHER: Leaks resulting from any other cause, such as exceeding the service life, not attributable to any of the above causes or inability to determine the cause of the leak.

If you are unsure how to categorize the cause of the leak, contact the Pipeline Integrity Program Manager or local Gas Operations Manager for assistance.

Hazardous Mechanical Fitting Failures

Mechanical fittings that result in a hazardous leak (Grade 1) are reportable to PHMSA, regardless of the leak failure cause including excavation damage. This also includes leaks that were originally graded as Grade 1 and downgraded prior to repairs being conducted.

Mechanical Fitting (Definition): Fittings that consist of specifically designed components including elastomer seals, O-rings, or gaskets and a gripping device to affect pressure sealing and/or pull-out resistance capabilities such as stab type, nut follower, and bolted type mechanical fittings. This applies to both steel and plastic fittings.
Some examples of mechanical fittings are as follows:

- Bolt-on service tees
- Bolt-on service tees with stab outlet or with a compression nut
- Steel welded service tees with compression outlet (if leak was in the compression outlet.
- Dresser couplings
- Service head adapters
- Couplings, tees, elbows, three-ways, caps, and stop-n-go fittings with stab connections
- Couplings, tees, elbows, three-ways, and caps with compression connections to include nut
- Repair clamps

Until further notice, cut out the fitting and send it to the Gas Materials Specialist in Gas Engineering (MSC-6). If you are unable to cut out or send in the component, contact the Gas Materials Specialist. Make sure to provide the appropriate service order number or work order number as applicable for the leak order the fitting represents.

5.12 REGULATOR AND RELIEF INSPECTION

SCOPE:

To establish an inspection and maintenance program for Avista's gas service regulators, district regulator stations, gate stations, and farm tap regulator stations. Also covered in this specification is inspection and maintenance on associated relief valves, safety shutoffs, monitors, and permanent blow down facilities (overpressure protective devices).

REGULATORY REQUIREMENTS:

§192.195, §192.197, §192.199, §192.201, §192.203, §192.619, §192.739, §192.741, §192.743

WAC 480-93-130, 480-93-140, 480-93-200

OTHER REFERENCES:

National Electric Code (NEC), Article 500 for Hazardous (classified) locations

CORRESPONDING STANDARDS:

Spec. 2.22, Meter Design
Spec. 2.23, Regulator Design
Spec. 2.24, Meter & Regulator Tables & Drawings
Spec. 2.25, Telemetry Design
Spec. 3.32, Repair of Steel Pipe
Spec. 5.13, Valve Maintenance

General

The information and procedures contained in this specification shall constitute the regulator and relief inspection and maintenance program for Avista. Only qualified, properly trained employees shall perform inspections and maintenance on company pressure regulating and pressure safety systems.

Before performing maintenance or construction activities at a gate station, regulator station, meter set, or other facility known to have telemetry, Gas Control must be called to notify them of the work. This will keep false alarm and alert notifications from being distributed. When work is complete, Gas Control must be called (509-495-4859 or via radio) again to ensure alarms and alerts have cleared before leaving the site.

Pressures Precaution

When performing maintenance that involves any regulator, regulating station, meter set, or overpressure protective device, the inlet and outlet pressures shall be continuously monitored on site using accurate pressure gauges if the device configuration allows this. If the device is not configured to allow on site monitoring, an alternate nearby location may be used, and Gas Engineering shall be contacted regarding revising the existing configuration to allow future on site monitoring. Care shall be taken when performing operations such as bypasses and stop-offs, so as not to allow the downstream or supply pressure to drop below normal operating limits. Any loss of pressure that may have extinguished pilots or that may have affected the normal operation of the customer's gas equipment shall be treated as an outage and the procedures followed as outlined in the GESH, Section 5, Emergency Shutdown and Restoration of Service.

Care shall also be taken not to allow the operating pressure to exceed the MAOP plus allowable buildup (or MOP) of the associated system. If it is determined that a system has exceeded the MAOP (or MOP), the employee shall immediately attempt to correct the situation and normalize the pressure. Downstream pressure checks shall be initiated to verify if any damage was caused by the over pressurization of the system. Gas Engineering shall be notified if either of the above-mentioned situations occurs as this may necessitate notification of the regulatory agencies.

SERVICE REGULATORS:

General Maintenance of all Service Pressures

Service regulators normally reduce distribution pressure to a pressure that is specified as the delivery pressure or utilization pressure. Utilization pressure for most residential customers in Avista's gas system is 7–inches WC (1/4 psig). Utilization pressure for some residential, commercial, and industrial customers may be 7–inches WC, 2 psig, 5 psig, or up to line pressure depending on load and other factors.

Service regulators are normally inspected or tested under the following circumstances:

- When a complaint is received from a customer regarding a suspected pressure problem, a noisy meter set, odors that may be resulting from a relieving regulator, a damaged meter set, or other related mechanical problems; or

- When a field employee notices a functional problem during the normal course of operations or when a related condition is made known by another employee. This includes problems apparent during the course of performing service orders, turn-ons, relights, new meter installations and inspections, etc.; or

- When meters and/or regulators are changed out or inspected under a company change out program (planned meter changes, recalls, retrofits, etc.).

The following should be checked by the field employee when performing an inspection on a service regulator:

- The general physical condition of the meter set should be checked. Attention should be paid to rust, meter sets in a bind due to settling, need for meter protection, tamper seals in place, index readable, etc.

- The regulator and/or relief vents should be clear and free from obstruction, the vent screen should be in place, and the vents should be oriented in a direction that will not allow water to enter. In the winter, care should be taken to keep ice and snow from enveloping the regulator vent as the vent may be frozen over and result in pressure problems.

- Flow and lockup pressure settings shall be checked and adjusted when installed and as necessary thereafter using a water manometer or a pressure gauge that is known to be accurate.

- The service regulator has overpressure protection.

- The age of the service regulator. Regulators on existing residential and commercial meter sets should be replaced when nearing 25 years and when an opportunity exists related to maintenance activities such as a Gas Periodic Meter Changeout (PMC). When an obsolete regulator is identified as detailed in Gas Standards Manual, Specification 2.22, Meter Design and Specification 2.24, Meter & Regulator Tables & Drawings, the regulator shall be replaced.

The field employee shall correct any abnormal conditions found on incidental inspections. The appropriate records should be noted if the meter set is under a maintenance program to avoid duplication of efforts.

Maintenance of Elevated Service Pressure Accounts

Elevated service pressure accounts that are **not** classified as industrial shall be maintained as follows:

Two and five psig metering pressure meter sets (residential and commercial) shall have the set pressure checked 180 days after initial installation and then as noted under “General Maintenance of All Service Pressures” in this specification. The filter/strainer should be checked if the pressure requires adjustment at the 180-day check.

In addition, these 5 psig metering pressure meter sets shall be checked during the regular testing cycle of diaphragm meters sized AL1400 and above, rotaries, and turbines.

At the time the meter is due for periodic testing per testing requirements in Specification 2.22, Meter Design, and the meter is either tested or changed out, maintenance should be conducted on the meter set per the requirements for “General Station Inspection” and “Annual Regulator Station Maintenance,” as applicable.

180-Day Inspection Criteria

New meter sets metering at greater than 7-inches WC and all rotary meter sets (regardless of metering pressure), require a one-time inspection at approximately 180 days of operation (no sooner than 150 days). Diaphragm meters will be inspected by Gas Service Persons; rotary meters will be inspected by the Gas Meter Shop. The following shall be verified and remediated as appropriate during the 180-day inspection:

- Flow and lockup pressures are in accordance with the customer billing code and applicable pressure.
- Verify meter configuration matches CC&B (Billing System) Correction Code
- Verify AMR device is operating
- Verify AMR device reading is tracking with CC&B (Billing System) read
- Check and adjust flow and lockup pressure as necessary
- Check overall condition (labeling, settling, paint, etc.)
- Check strainer as necessary. Clean strainer if necessary.
- For rotary meters, complete the initial differential test.

In some cases, the customer piping may not be connected, or the meter may not have been used at the 180-day check. In this situation, an additional order shall be requested for a subsequent 180-day check to be completed.

Maintenance of Industrial Meter Sets

A meter set that meets any of the following conditions is considered an industrial set:

1) A set metering at pressures above 5 psig (**Note:** metering pressure, not delivery pressure)
2) A rotary meter size 16M or larger regardless of metering pressure
3) A turbine meter
4) Any set with an hourly design load equal to or above 14,600,000 BTU/Hr
5) Meter correction code of 3 or P

Elevated service pressure accounts classified as industrial shall be maintained per the requirements under “General Station Inspection” and “Annual Regulator Station Maintenance” as described within this specification.

REGULATOR STATIONS AND ELEVATED PRESSURE METER SETS:

Farm Taps

A Farm Tap (sometimes referred to as a Single Service Farm Tap – SSFT) is a pressure regulating station that controls pressure to a service line. Pressures will normally be reduced from pressures over 60 psig down to an intermediate pressure that is commensurate with the load (typically 25 - 45 psig). Normally, an overpressure protection device is provided by a relief valve or safety shutoff. A Farm Tap style pressure regulating station is considered a district regulator station if it serves downstream main piping and must be maintained as such.

Farm Taps with an upstream source of gas being fed from a transmission line (Interstate or Avista) without other pressure regulation upstream shall be maintained as a district regulator station once every three years not to exceed every 39 months. Refer to Specification 2.24, Meter & Regulator Tables & Drawings for an example drawing of a Farm Tap regulator station design.

District Regulator Stations

A District Regulator Station is a pressure regulating station that controls pressure to high-pressure or low-pressure distribution main. It does not include pressure regulation whose sole function is to control pressure to a manifold serving multiple customers. Master meter stations and bypass customer stations are treated like district regulator stations and are maintained accordingly.

District Regulator Stations vary in design depending on the load demands and size of the system, physical location, construction limitations, availability of parts, etc. These stations will typically reduce high pressure gas (over 60 psig) and they will normally use either a relief valve or a monitor valve for overpressure protection. Refer to Specification 2.24, Meter & Regulator Tables & Drawings for examples of drawings of typical regulator station designs.

District Regulator Station Relief Capacity Review

Gas Engineering is responsible for reviewing district regulator stations which utilize relief valves as the overpressure protection device to assure that the relief valve has adequate relief capacity (refer to Specification 2.23, Regulator Design). If the relief does not have adequate capacity based upon the calculation, it shall be replaced, or restrictors installed on the regulator(s) based on the recommendation of Gas Engineering. System deficiencies that could potentially result in the overpressure of the downstream system should be modified within 30-days. Other deficiencies that do not pose an immediate threat to system operation should be modified during annual regulator station maintenance or prior to the end of the calendar year, whichever occurs first. This review must be conducted once every calendar year, not to exceed 15 months. Relief capacity review records shall be kept for minimum of 5 years.

The relief capacity calculations must be compared to the rated or experimentally determined relieving capacity of each device for the conditions under which it operates. After the initial calculations are made / reviewed, subsequent calculations do not need to be performed if the annual review documents the fact that parameters have not changed to cause the previous relief capacity calculations to no longer be valid.

Gate Station Regulator and Relief Set Point Review

At each gate station where the interstate pipeline is responsible for pressure reduction, Gas Engineering is responsible for gathering the current regulator and relief valve set point information. Gas Engineering shall review set points for regulators (worker and monitor) and relief valves to ensure an appropriate delivery pressure and overpressure protection. Set points must not exceed the MAOP (+10 percent) of the downstream Avista facilities. If set points exceed MAOP (+10 percent), Gas Engineering shall notify the respective interstate company to have the set points revised. This review must be conducted once every calendar year, not to exceed 15 months.

Regulator Station Numbering

Refer to Specification 2.23, Metering and Regulation, "Regulator Station Numbering, "for guidance on numbering of regulator stations.

General Station Inspection

A station inspection should be performed each time a district regulator station, city gate station, elevated pressure meter set, or farm tap is visited. (If bypassing of the station is required, the Station Bypassing Procedure within this specification should be followed.) The field employee should note the following and take appropriate action to resolve any deficiencies:

- The general condition of the station. It should be free of debris and weeds. Access to the station should not be impaired, and all station entry doors, locks, and gates shall operate freely. It shall be verified that the station is properly barricaded or protected from damage. Necessary warning signs and station identification signs shall be in place and in good condition. In addition, the signs shall have the correct phone number and other pertinent information and be properly mounted.

- Ventilating equipment installed in station buildings or vaults should be checked for proper operation. Electrically operated ventilating equipment shall not be operated until it is determined that it conforms to the applicable requirements of the National Electric Code (NEC), Article 500 for Hazardous (classified) locations. A check should be done for accumulations that may prevent proper venting to atmosphere.

- In cases where the station pressure is being adjusted or verified, the inlet and outlet flow pressures shall be checked with a pressure gauge known to be in calibration.

- The relief (or safety shutoff) shall be checked to verify that the shutoff valve isolating it from the system is locked in the open position. The vent stack cap on the relief should also be checked for free operation.

- Security fences and cages (where present) shall be locked for security purposes when access to the facility is not required.

- Station valves and locking devices shall be checked to ascertain that they are functioning, and that the valves are locked, or handles removed to prevent tampering, and that they are in the correct position. **(Both above and below ground station valves with the exception of inlet and outlet emergency valves already being maintained shall be serviced at this time.)**

- The station should be leak tested if a gas odor is present.

- Cathodic protection wires and fittings shall be checked and repaired as necessary.

- Station equipment that is abandoned or not in use shall be removed so as not to create a hazard.

- As the last step before exiting a station, a visual inspection shall be performed to verify all equipment and valves are in the correct operating positions before locking devices are installed.

Conditions found that are not up to operating standards should either be corrected upon discovery or scheduled for repair as soon as possible. Hazardous conditions shall be corrected immediately.

Farm Taps and HP Services

Farm Taps (SSFTs) and High Pressure Services are visited every three years (not to exceed 39 months) for an Atmospheric Corrosion Inspection. Additionally, a "General Station Inspection" as noted above shall be performed. A flow and lockup test may be performed if the site is appropriately configured; however, this action is not required. See "Farm Taps" subsection in this Specification for an exception to these stated maintenance requirements for farm taps with an upstream source of gas being fed from a transmission line.

ANNUAL REGULATOR STATION MAINTENANCE

In addition to the general station maintenance items listed above, the district regulator stations shall receive the following attention under the annual regulator station inspection. If bypassing of the station is required, the Station Bypassing Procedure within this specification should be followed. The Manufacturer's Operating Instructions shall be consulted as applicable.

Maintenance Procedure

The station outlet flow pressure as found and as left at the station shall be checked and recorded on the Regulator Station Inspection and Maintenance Record (form N-2527). If the regulator is pulsating or otherwise acting abnormally, it should be readjusted or disassembled and inspected internally. The outlet station pressure shall be set to the value shown on the regulator inspection record. A suitable, accurate pressure gauge shall be used for all pressure checks. MAOP's and MOP's may differ from one district regulator station to another, so it is important to check the records before performing maintenance or setting pressures on a station.

- The station lockup pressure shall be verified, if readily allowed by existing station design, and noted on the inspection record.

- If the regulator is disassembled, the orifice, seat, diaphragm, or boot shall be inspected and replaced as necessary.

- Pilot filters should be cleaned or replaced as necessary. Pilot loading lines shall be inspected for debris or flaking and cleaned as needed.

- Regulator and pilot vents shall be leak tested. Leakage usually indicates a defective diaphragm or other malfunction. The regulator or pilot shall be repaired or replaced as necessary. Replace cracked or broken regulator or pilot vent caps. Check to make sure that regulator vents are positioned in the downward position or has a vent elbow installed. Check to make sure any vent screens are in place and are not damaged.

- Replace damaged gaskets or O-ring seals on regulator or pilot as necessary.

- Replace items on a regulator or pilot if subject to manufacturer's recall or update.

- Check the condition of the downstream sensing or control lines. Assure control lines are not damaged or bent. Check the operation of any line valves. Repair or replace as needed.

- The responsiveness of the regulator shall be verified by checking stroke or by placing the regulator back into service and observing downstream pressure.

- Flange bolts shall be checked to make sure that they extend fully through the nuts and that no flange bolts are missing. If a flange bolt-hole is threaded and no nut is required, make sure that the bolts are long enough to thread through both flanges.

- The station shall be visually inspected for signs of atmospheric corrosion (rusting or pitting). Special care should be taken to inspect for pitting around fittings that could result in a failure. Adjustable pipe supports shall be repositioned, and the pipe surface inspected for the evidence of corrosion. Non-adjustable pipe supports should be visually inspected at the pipe interface for any evidence of corrosion.

- Insulating material should be in place and in good condition between the carrier pipe and the support. Risers in the station shall be inspected to ensure the coating is appropriate for above ground installation and is above the soil-to-air interface and not disbonded. Above ground wax tape is the preferred coating for steel risers at the soil-to-air interface. X-Tru coating shall not be used for new installations but may be left in the field on existing stations if the coating is not cracked or degraded and covered with a well bonded gray enamel paint. Cracked or degrading X-Tru coating must be repaired with above ground wax tape. In addition to station piping, supporting members shall be inspected for corrosion and/or damage. If there is evidence of significant corrosion per Specification 3.32, Repair of Steel Pipe, contact Gas Engineering.

Information pertaining to the inspection of the regulator shall be recorded on the appropriate regulator station inspection and maintenance record.

Maintenance of Overpressure Protection Devices

Overpressure protection devices (including relief valves, monitor regulators, and safety shutoff valves) shall be inspected and tested once each calendar year.

Overpressure protection devices shall be inspected to ensure the following:

- They are in good mechanical condition.

- They have a vent stack that is not restricted and is positioned away from sources of ignition. Vent caps and screens shall be checked for obstructions, for proper operation, and to determine that the screens are intact. Replace or repair any defects.

- They are set to function at the correct pressure by using an accurate test gauge. The regulator inspection and maintenance record shall be consulted to determine the relief maximum set point as specified by Gas Engineering. In some cases, the relief set point may be less than the MAOP due to operating restrictions.

- They are properly installed and protected from dirt, liquids, and other conditions that might affect proper operation.

- Sensing lines, control lines, filters, restrictors, etc. on relief valves have been inspected and repaired as necessary.

Relief and Safety

Bottled nitrogen or bottled CNG should be used when possible to pressurize and test relief and safety shutoff valves. This procedure avoids the unnecessary release of natural gas into the atmosphere and is also safer than allowing full relief of natural gas at the station (refer to the Nitrogen or CNG Relief Testing Procedure within this specification).

Precautions should be taken to isolate the relief or safety shutoff valve from the system before testing to avoid overpressurization, or contamination of the downstream system with nitrogen.

If the relief or safety shutoff does not operate within the specified parameters (maximum set point), it shall be adjusted to conform to the required set point. If adjustment does not provide the desired results, then the relief or safety shutoff must be repaired or replaced.

Monitor Testing

Monitor regulators shall be isolated from the system and operated to confirm that they will control pressure at the proper set point and that they will lockup. Any deviation from normal operation shall be corrected by repair or replacement. Service monitor regulators according to the guidelines for "Regulator Maintenance" or according to procedures for "Regulator and Relief Overhaul".

Strainer/Filter Inspection

Station filters or strainers should be either visually inspected or tested by differential flow test. They should be cleaned or replaced as necessary per manufacturer’s instructions.

Station Valves

Valves shall be checked for proper operation and lubricated as necessary per Specification 5.13, Valve Maintenance.

Maintenance of Blow Down Facilities

Blow down facilities located on transmission pipelines, at regulator stations or at gate station facilities shall be inspected once each calendar year, not to exceed 15 months. Valves on blow down facilities shall be checked for proper operation and lubrication as necessary per Section 5.13, Valve Maintenance. Purge any excess pressure that may exist between the normally-closed blow down valve and the stack closure fitting as necessary prior to the start of and at completion of maintenance.

Changes in Station Design

Modifications to existing regulator station designs must be approved by Gas Engineering.

Maintenance of Regulator Stations Operating on Permanent Bypass

Annual regulator station maintenance is not required on stations currently operating on permanent bypass. These stations shall be visited every 3 years (not to exceed 39 months) for an Atmospheric Corrosion Patrol. If a station is to be reinstated from permanent bypass the regulator station shall receive the inspection and maintenance items listed under “Annual Regulator Station Maintenance” prior to being placed back into service in the field. Information pertaining to the inspection of the station shall be recorded on the appropriate Regulator Station Inspection and Maintenance Record.

Portable Regulator Station Maintenance

A portable regulator station shall receive the inspection and maintenance items listed under "Annual Regulator Station Maintenance" every time the station is placed into service in the field. There is not an additional requirement to conduct inspection and maintenance on portable regulator stations annually not to exceed 15 months. Information pertaining to the inspection of the station shall be recorded on the appropriate Regulator Station Inspection and Maintenance Record.

Portable CNG Trailer Maintenance

Portable CNG trailers shall receive the inspection and maintenance items listed under "Annual Regulator Station Maintenance" once each calendar year not to exceed 15 months. Information pertaining to the inspection of CNG trailers will be recorded on the appropriate Regulator Station / Industrial Meter Inspection and Maintenance Record form (N-2527). The Fleet Department is responsible for inspecting and maintaining the CNG tanks, CNG tank valves, and all vehicle related items.

In addition to annual maintenance, CNG trailers should be inspected before each use to ensure the regulators are set appropriately and that the trailer is functioning safely. A CNG Trailer Regulator Inspection form (N-2711) should be filled out each time the trailer is placed into service. A single form should be kept with each trailer, so all users of the trailer are filling out the same form. The Pressure Controlmen responsible for performing annual maintenance on the trailer should replace the form annually and keep the form in case the document is asked for during an audit.

Regulator Stations – Special Inspections

If there are indications of abnormally high or abnormally low pressures in a system, regulators and applicable auxiliary equipment within the regulator station must be inspected and necessary measures employed to correct the unsatisfactory operating condition.

5 YEAR OVERHAUL – FLEXIBLE ELEMENT & BOOT TYPE REGULATORS AND RELIEF VALVES:

Maintenance Procedures

In addition to the annual station maintenance and portable regulator station maintenance, every 5 years each flexible element or boot type regulator (to include portable regulator stations as applicable) shall include the following internal inspection:

- Flexible elements or boots shall be visually checked for cracks, wear, etc., and replaced as necessary.
- Gaskets, O-rings, discs, seals, etc. should be replaced as necessary.

The overhaul procedure may be performed in the field or in the shop. It may prove to be convenient to have the regulator or relief device overhauled in the shop and have it ready so that it may simply be exchanged in the field.

10 YEAR OVERHAUL – DIAPHRAGM TYPE REGULATORS, RELIEF VALVES & PILOTS:

Maintenance Procedures

In addition to the annual station maintenance and portable regulator station maintenance, every 10 years each diaphragm type regulator and pilot (to include portable regulator stations as applicable) shall include the following internal inspection:

- Diaphragms shall be visually checked for cracks, wear, etc., and replaced as necessary.
- Orifices and seats shall be visually inspected for scoring, pitting or other damage and replaced as necessary.
- Pilot filters shall be replaced.
- The pilot valve and seat shall be inspected for wear and repaired per manufacturer's recommendations.
- Gaskets, O-rings, discs, seals, etc. should be replaced as necessary.

The overhaul procedure may be performed in the field or in the shop. It may prove to be convenient to have the regulator or relief device overhauled in the shop and have it ready so that it may simply be exchanged in the field.

<u>Exclusion</u>: Small diaphragm type regulators and relief valves used in farm tap regulator stations or meter sets would not need to be overhauled unless the regulator or relief valve does not function properly during the general station inspection or annual regulator station inspection. However, it may prove more convenient to replace the regulator or relief valve rather than to perform the internal overhaul in the field.

GATE STATIONS:

Avista-owned facilities in gate stations shall be serviced under the same annual maintenance schedule as district regulator stations. Maintenance procedures shall be the same for the station, pressure regulators, and overpressure protective devices.

Field employees performing maintenance on gate stations shall be properly trained on such maintenance, and shall be familiar with the layout of the station, including the locations of all shutoff valves, feeds, odorizers, charts, telemetry devices, etc. Consideration should be given to notifying Gas Supply and/or the System Operator, as well as the transmission pipeline supplier when maintenance is to be performed at gate stations.

Chart Recorders and Telemetry

When a mechanical chart recorder is used at a district regulator station, it should be inspected on a monthly basis. The chart should be changed at this time and the pens should be checked and changed as necessary. The downstream operating pressure should also be checked with a calibrated pressure gauge and cross checked against the chart reading. If any discrepancy is detected, the chart recorder should be repaired or replaced. If a chart recorder is being utilized, it shall also be inspected during the annual regulator station inspection and maintenance.

Inspections and calibrations on telemetry devices and electronic pressure recorders at gate stations and multi-fed distribution systems shall be performed once each calendar year to verify high- and low-pressure alarms are functioning properly. This can be accomplished by checking information relayed to the System Operator or Gas Supply with actual pressures at the gate station or telemetry location. Problems with telemetry equipment shall be referred to the appropriate department for repair as soon as they are detected. If the telemetry system is not functioning properly, a pressure recorder should be set at the same location site to validate functionality of the equipment or if the telemetry system is down for repair for an extended length of time. Refer to Specification 2.25, Telemetry Design for additional information on the design and installation of telemetry devices.

<u>Company field personnel shall respond to all alarms generated by telemetry equipment that may indicate a potential safety problem</u>. If there are indications of abnormally high or low pressure, the regulator and the auxiliary equipment must be inspected, and the necessary measures employed to correct any unsatisfactory operating conditions.

MAINTENANCE FREQUENCIES:

Avista's gas distribution regulator stations and gate stations shall be inspected and maintained according to the following schedule:

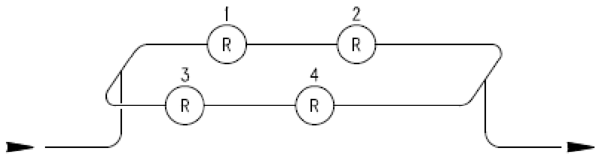
Station Type	Interval
District Regulator Station	Once each calendar year (Not to exceed 15 months)
Gate Stations	Once each calendar year (Not to exceed 15 months)
Farm Taps (AC and General Inspection at minimum)	Once every 3 years (Not to exceed 39 months)
Farm Taps (Upstream source fed from a transmission line)	Once every 3 years (Not to exceed 39 months)
Portable CNG Trailers	Once each calendar year (Not to exceed 15 months.)
Portable Regulator Stations	Every time the station is placed into service.
Industrial Meter Sets	Annually

Maintenance shall be based on the anniversary date established and required maintenance shall be completed before expiration of the grace period. On existing stations, the last date serviced establishes the anniversary date.

Recordkeeping

Maintenance performed on district regulator stations, gate stations, and farm taps shall be recorded on the appropriate Regulator Station Inspection and Maintenance Record (form N-2527) (electronic or paper) and retained for the life of the facility. Relief Capacity Review records shall be kept for a minimum of 5 years.

When identifying regulators on the Inspection form, use the following identification sequence for the various configurations shown: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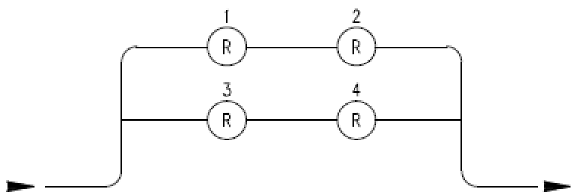
R
2
R
3
R
4
R


1
R
2
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3
R
4
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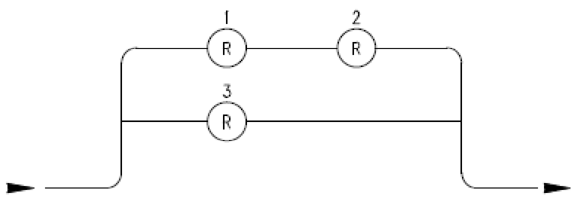
1
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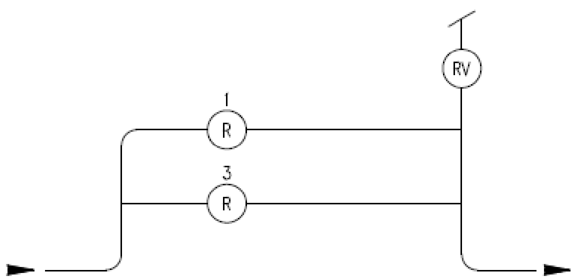
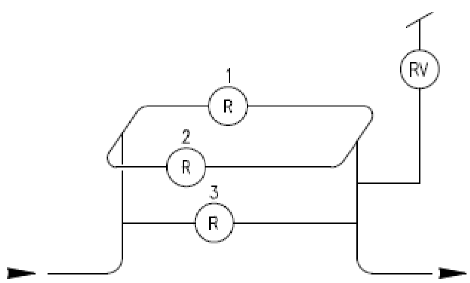
2
R
3
R


RV
1
R
3
R


RV
1
R
2
R
3
R

PROCEDURE FOR REGULATOR STATION AND METER SET BYPASSING:

The following procedure should be adhered to when placing regulator stations and meter sets that have a non-regulated, hard-piped bypass installed. Care shall be exercised during all phases of the bypass operation in order to ensure that the system pressure is adequately maintained. Gas Supply, as well as the applicable pipeline transportation company, shall be advised whenever a gate station is put on bypass. (NOTE: The following procedures are applicable only to regulator stations with fixed bypasses.) If utilizing this procedure for low pressure situations (cold weather actions), skip steps #5, #7, #8, and #12. These steps are used to take the regulators out of service for maintenance purposes.

1. Make sure that necessary tools, parts, and safety equipment are available at the job site before proceeding with the bypass procedure.
2. Take an accurate upstream pressure reading. It is not necessary to continuously monitor the upstream pressure during the bypass operation.
3. Install an accurate pressure gauge on the downstream side of the station. Note the outlet pressure. Leave this gauge in place during the entire bypassing operation.
4. Unlock all station valves. If required by design, install temporary soft bypass hose. Test valves by partially operating them.
5. Crack open the station bypass valve. Close the downstream station valve, and then check the downstream pressure. It may be necessary to also close the sensing line valve to achieve lockup, depending on station design. Modulate the bypass valve as required to maintain system pressure. Use caution not to open the bypass valve too much as you may run the risk of overpressuring the system.
6. Close the upstream station valve to complete the isolation of the regulator(s). The station is now on bypass.
7. Continue to note the downstream pressure readings. Adjust bypass valve to maintain but not exceed downstream system pressure.
8. Blow down isolated section to atmosphere and perform station maintenance as required.
9. To put regulator(s) back into operation, start by opening the upstream station valve slowly until it fully pressurizes the regulator and loads the pilot (if applicable). Regulator adjustment screw should be backed off before placing regulator back into operation to avoid possible overpressuring of downstream prior to final pressure adjustments.
10. Open the downstream valve slowly.
11. If applicable, open the control line slowly. The regulator should now begin to control pressure.
12. Close the bypass valve. The station is now off bypass. Remove temporary soft bypass if one was used. Cap and plug all appropriate valves and fittings.
13. Adjust the regulator(s) to the proper set point(s) while observing the downstream pressure gauge. Allow sufficient time for pressures to equalize while making adjustments. Tighten locking nuts in place when done.
14. Check all valves used during operation for leakage. Adjust or lubricate as necessary. Double check the positions of all valves and locks are in place.

PROCEDURE FOR TESTING RELIEF VALVES WITH NITROGEN OR BOTTLED CNG:

This procedure is suggested for use in testing the performance of relief valves in the field. It is recognized that this procedure will not be applicable in all cases due to difference in relief and regulator design. The following procedure does, however, provide for pressurization and testing of certain relief valves without the possibility of overpressuring the downstream pipe.

1. Install an accurate pressure gauge on the downstream side of the station to monitor system pressure while the relief is shut down.
2. Temporarily isolate the relief from the system by unlocking and closing the manual relief isolation valve.
3. Proceed with the testing and pressure setting of the relief, as found. Should it be necessary to perform maintenance on the relief valve de-pressurize the relief valve and piping prior to proceeding with the necessary repair.
4. Install a field fabricated device into a port that will pressurize the appropriate section of the relief valve. The device should consist of a pressure gauge of range appropriate to the relief setting, a section of pipe nipple that will allow it to be screwed into the body of the relief, and a valve rated for the pressure being used. It is also convenient to install a quick connect fitting on one end so as to facilitate easy connection.
5. Make sure that the control valve on the device is in the "off" position. Connect the device with a hose (rated for the appropriate pressures) to a supply tank of nitrogen. The supply tank should have its regulator set at a pressure that will allow the relief to be tested fully.
6. Slowly turn on the valve on the supply tank until the hose is pressurized.
7. Slowly open the control valve on the device to begin pressurizing the relief. Observe the pressure gauge while gradually increasing pressure with the control valve (throttling). Note the pressure at which the relief opens and make adjustments as necessary. Repeat the pressurization process several times to eliminate the possibility of the relief sticking.
8. Adjust the relief set point as specified by Gas Engineering on the appropriate records.
9. When the proper setting is achieved, turn off the supply valve on the nitrogen bottle and the control valve on the device. Disconnect the hose and de-pressurize the relief.
10. Remove the relief testing device from the relief and re-install the fitting or plug removed to install the device.
11. Open the manual relief isolation valve to put the relief back in service.
12. Lock valve in open position.

In some instances, such as in the case of smaller sized relief valves, the relief valve may temporarily be removed from the station and "bench tested" on the service vehicle using bottled nitrogen. The field employee performing such testing should exercise good judgment in the test methods and equipment used.

5.13 VALVE MAINTENANCE

SCOPE:

To establish an inspection and maintenance program for Avista's gas distribution and transmission pipeline valves.

REGULATORY REQUIREMENTS**:**

§192.145, §192.179, §192.181, §192.363, §192.365, §192.745, §192.747

WAC 480-93-018, 480-93-100

CORRESPONDING STANDARDS**:**

Spec. 2.14, Valve Design
Spec. 3.32, Repair of Steel Pipe

General

The information and procedures contained in this section shall constitute the valve maintenance program for Avista. Only personnel trained and qualified in maintenance of various valve types and designs shall perform maintenance on Company valves. Included in this section are procedures for proper valve maintenance, basic installation and operating requirements, valve maintenance categories and frequencies, and recordkeeping. The individuals performing valve maintenance will notify Gas Control of the area they will be performing maintenance for the day. If part way through the day the work moves to a different area, update Gas Control. When finished, or at the end of the day, notify Gas Control that the crew has completed valve maintenance work for the day.

VALVE TYPES:

Steel Plug Valves

Most of the existing steel valves used in Avista's systems are of the Rockwell-Nordstrom plug valve design. The basic design of the Nordstrom valve consists of a body, plug, cover, resilient adjustment member, and the sealant. The function of each component part is detailed below:

The Body - Its purpose is to connect the valve to the pipeline and mate with the plug to form a pressure vessel capable of operation under various pressures depending on the end connections and the cover design.

The Plug - The plug is the only moving part. It has a tapered surface designed to mate with the body to provide a tight seal between the body and plug. The plug has a machined port through which gas flows when the valve is in the open position.

The Cover - The cover retains the resilient adjustment member and prevents external leakage.

The Resilient Adjustment Member - This consists of a diaphragm to allow plug movement without leakage, a self-energizing packing ring to maintain force against the plug and a gland to set tension against the resilient packing. The resilient adjustment member varies according to design. For instance, in the Rockwell Hyperseal valve (with an inverted plug), it is a spring disc or bottom cover.

The Sealant - The sealant functions as a seal against leakage and also hydraulically lifts the plug from its seat in the body to provide ease of operation and to prevent sticking. The lubricated plug valve operates on a closed hydraulic system, utilizing the hydraulic force of the lubricant to lift the plug from its locking taper seat for operation. The resilient member reseats the plug to prevent leakage.

Nordstrom plug valves will normally require 1/4 turn to close or open the valve. Valves are turned CLOCKWISE to CLOSE and are turned COUNTERCLOCKWISE to OPEN. Standard Rockwell-Nordstrom valves turn clockwise to close, unless otherwise specified. Plug valves designed by other manufacturers will normally have the same design features as the Rockwell-Nordstrom type valves; however, manufacturer's instructions and specifications should be consulted before installing or maintaining such valves.

Steel Gate Valves

Gate valves are steel valves designed so that a threaded stem with a steel gate or conical end screws down and seats in a receptacle so as to shut off the flow of gas. Shut-off is achieved without use of a lubricating sealant. Valve design enables the gate or conical end to seal with either elastomers or metal-to-metal contact. Valve stem seals are maintained by use of elastomer "O" rings. Gate valves require multiple turns to open or close the valve. Valves are turned CLOCKWISE to CLOSE and are turned COUNTERCLOCKWISE to OPEN.

Steel Ball Valves

Steel ball valves are designed so that a ball inserted in the valve has a cylindrical bore in it through which gas flows when the valve is in the open position. When the valve is operated, the ball rotates, and the flow is stopped due to the bore being perpendicular to the flow. Ball valves require 1/4 turn to open or close the valve. Valves are turned CLOCKWISE to CLOSE and are turned COUNTERCLOCKWISE to OPEN. Leakage is controlled through the use of nylon or Teflon seals around the ball and O-ring seals around the operating stem.

Gear Valves

The term "gear valve" normally applies to a larger plug or ball valve that uses a worm gear and other reduction gears for operation. The gear system may either be exposed or concealed depending on the particular valve design and application. Each type and size of gear valve will take a varying number of turns on the operating handle to open or close the valve.

Polyethylene Valves

Valves constructed of polyethylene plastic are available and used in plastic distribution systems. These valves are either of the ball or plug design. These valves will require 1/4 turn to open or close the valve. Valves are turned CLOCKWISE to CLOSE and are turned COUNTERCLOCKWISE to OPEN. Less torque is required to open and close these valves. Due to their plastic design, these valves can be easily over-torqued, and valve stops damaged. Particular care needs to be taken when operating and the use of a cheater bar is prohibited.

Valve Turns

The table below lists the approximate number of turns for each valve type. (The information is meant to be for reference only and should be verified as applicable.)

Size (in)	# of Turns	Notes
Plug Valve – Spur Gear Reduction		
6	1-9⁄16	Rockwell/Nordstrom part number ending in 7.
8	1-9⁄16	
10	2	
12	3-3⁄16	
16	4-½	
20	7-9⁄16	
24	9-¼	
Plug Valve – Worm Gear Reduction		
6	12-½, 15	Rockwell/Nordstrom part number ending in 9. There are several models available depending on class rating, etc.
8	12-½, 15, 17	
10	16, 17, 22	
12	19-½, 22, 62-½	
Plug Valve – Non-geared		
2-6	¼ Turn	
Gate Valve – Kerotest		
2	7-¼	
3	10	
4	13-¼	
6	19-¾	
8	26-¼	
10	21-¾	
12	25-¾	
Mueller Inline Curb Valve and Tee		
1	7-¼	
1 ¼	8-¼	
2	10-¾	
Mueller Curb Valve Tee w/ Autosafe PHUSE EFV		
1	4-¾	
Polyethylene Ball Valve		
All Sizes	¼ Turn	Minimal Torque Required

MAINTENANCE REQUIREMENTS FOR VALVE TYPES:

Steel Plug Valves

These valves require a periodic injection of sealant to provide enough pressure in the valve to provide positive shut-off. Plug valves shall be turned and should be lubricated, as needed at the time of their scheduled maintenance. Other valve adjustments should be performed as necessary by trained field personnel. Refer to the "Plug Valve Lubrication Procedures" for detailed lubricating instructions.

Lubrication risers may be installed on plug valves as needed. Half-inch schedule 80 pipe should be used to bring the lubrication fitting close to the surface. The riser should be packed with fresh lubricant before installation. Field personnel qualified to operate valves shall have a hollow valve key to allow operation of valves with risers installed. Local construction offices are encouraged to standardize valve key sizes.

Extreme care must be exercised when installing risers, installing, or replacing lubrication fittings, and when lubricating valves so that foreign debris does not get inside the valve or its lubricant. The introduction of any foreign material in the valve may plug the lubrication ports and channels, and may result in leakage, binding, or scoring of the plug.

Steel Gate Valves

Gate valves shall be checked for leakage and ease of operation on an as needed basis (annually if they are Emergency valves). They do not require field lubrication as O-ring seals control leakage. After it is verified that the valve turns acceptably, field personnel should open the valve fully to seat the stem against the O-ring seal. If the valve leaks, the valve should be scheduled for replacement or overhaul.

Steel Ball Valves

Modern ball valves normally do not require any maintenance other than verifying they turn properly and are not leaking.

Some ball valves (new or old) are fitted with external grease fittings to be used if the valve fails to give tight shut-off. These ball valves should NOT be greased unless they fail to seal tightly. If greasing is required to obtain shut-off, the valve may need to be greased as part of its normal maintenance. Use a valve lubricant that is specified by the ball valve manufacturer.

Ball valves that are designated Emergency valves shall be turned and inspected on an annual basis. Other ball valves shall be inspected on an as needed basis. Ball valves that are leaking or that do not turn properly should be greased (if possible), repaired, or replaced.

Steel Gear Valves

Gear valves that are of the Nordstrom plug design shall also be injected with sealant to provide ease of operation and positive shut-off. Gear operated ball valves shall be maintained as mentioned above when they fail to turn properly. The worm gear and other gearing mechanisms shall also be lubricated and adjusted to achieve acceptable operation. Emergency gear valves shall be lubricated and adjusted on an annual basis. All other gear valves shall be lubricated and adjusted on an as needed basis if they are found leaking or hard to turn. Enclosed gear valves should be packed with an appropriate grease to prevent water accumulation and corrosion.

Polyethylene Valves

Plug and ball valves constructed of polyethylene normally do not require any maintenance other than verifying that they turn properly and that they are not leaking. Polyethylene valves that are designated Emergency valves shall be turned and inspected on an annual basis. Other polyethylene valves shall be inspected on an as needed basis. Polyethylene valves that are leaking or that do not turn properly should be replaced.

GENERAL VALVE MAINTENANCE AND INSTALLATION NOTES:

General

Prompt remedial action shall be taken to correct any emergency valve that is found inoperable, unless an alternative valve has been designated as a replacement.
As part of the maintenance activity, documentation regarding the valve shall be verified, including valve number, mapping, status (open or closed), and valve attributes if known.

For the purpose of maintenance, a valve shall be considered operable if the valve can be “broken loose” from its normal operating position and turned slightly. It is recommended to close a valve at least 25 percent of the way to test its operation. It is acceptable to operate valves up to 100 percent where practical and there is a reduced risk of outage. The direction of the pipeline and the position of the valve should be verified by utilizing the valve stops and the position indicator on the valve itself. If this cannot be verified, notify the local gas manager to discuss next steps before attempting to perform maintenance. Mark your starting point so that there is an indication of where to reposition the valve after turning. This may be accomplished using temporary marking such as white paint if weather conditions allow. **Ensure that the valve is being turned in the proper direction.**

For normally closed valves separating two distinct pressure zones, it is recommended that these valves be evaluated and considered for removal. If removal is not practical, it is recommended during maintenance that these valves be serviced, cleaned, and lubricated as necessary, but <u>**do not operate the valve**. To “crack” a valve (turn the stem just enough to move it off the stops) is not considered operating</u>. Operating these valves could result in an uncontrolled overpressure condition on the downstream system. If the valves must be operated, system pressures downstream of these valves must be monitored closely and significant care taken not to overpressure the downstream system.

Use care when operating valves. A single serviceperson should be capable of operating any valve during an emergency. If operation of the valve requires more force than a reasonable person can apply, the valve should be considered for maintenance or replacement. Hard to turn plug valves should be lubricated if possible before attempting to turn them again. For hard to turn valves, the use of a valve flush may help in freeing up the valve. For hard to operate steel valves, if alternative methods of lubrication are not possible or successful, it is acceptable to apply a lubricant or a penetrating oil (external use only) to aid in the operation of the valve.

Forcing valves could result in damage to worm gearing, shearing of the stem, cracked or distorted bodies, broken locking devices, etc. Use the proper wrench for the valve being worked on. Damaged or compromised valves shall be replaced.

Pipe alignment and support is particularly critical in large above ground valve installations. During valve maintenance on above ground valves, care should be taken to ensure necessary supports are in place.

Maintaining Valve Boxes

Valves boxes should be thoroughly cleaned out when servicing valves to prevent corrosion and for ease of operation. If a valve box regularly fills with sediment or debris, consideration should be given to moving the valve. Lids should be easily removable and should be identified by painting the outside of lid yellow.

To allow for quick field verification of emergency and secondary valves, a short section of small diameter polyethylene pipe, or something similar made of a non-corrodible material, should be placed in the valve box with the valve number either written in permanent marker or tagged to it.

Valve Disable / Abandonment

When it is determined that a valve will no longer be used in the gas distribution system, it shall be either disabled or abandoned.

Disabled Valve: A valve that has gas flowing through it but is no longer operable.
Valves can be disabled in the following ways:

1. Made inoperable by canning/barreling or capping
2. Is inaccessible (i.e., under pavement)

Abandoned Valve: A valve that has been physically removed or disconnected from the piping system such that gas will no longer flow through it.

If the valve is to be disabled, the valve is identified as "Disabled" on the maintenance record and on Company maps. Valve maintenance is no longer performed on the valve, but the past maintenance records should be kept until the valve is abandoned (removed) from the system.

Maintenance

Avista gas distribution and transmission valves, based on the criteria established in Specification 2.14, Valve Design, shall be maintained to make operable and serviced according to the following schedule:

Valve Category	Frequency
Emergency Distribution & Transmission Valves (Valves as specified in §192.179 and §192.181) that are necessary for Emergency Operations	Once each calendar year, not to exceed 15 months
Emergency Curb Valves (Inaccessible meter sets, churches, schools, hospitals, jails, convalescent homes, etc.)	Once each calendar year, not to exceed 15 months
Regulator Station Isolation Valve(s) (isolation valves as specified by §192.181(b))	Once each calendar year, not to exceed 15 months
Secondary Valves	Every five years not to exceed 63 months (This is a Best Practice but not a requirement)

WAC 480-93-100 (2): In the state of Washington, Emergency Curb Valves newly installed *or pre-existing* that meet the criteria identified in Specification 2.14, Valve Design, “Emergency Curb Valves,” shall be maintained once each calendar year, not to exceed 15 months.

As part of the initial installation of a valve, the valve will be viewed as receiving the required maintenance. During road projects, both Emergency and Secondary valves should be maintained during the process of the temporary lowering of the elevation of the valve box. Ensure the maintenance activity is appropriately documented to avoid duplication of the maintenance effort at a later date.

A compliance date shall be assigned to all newly installed emergency valves. Subsequent maintenance shall be based on the date established and required maintenance shall be completed before expiration of the grace period (as long as the grace period is within the calendar year).

Above ground gas carrying portions of valves shall receive an atmospheric corrosion (AC) inspection and applicable AC maintenance as required by §192.479 and §192.481 during required valve maintenance actions.

Secondary Valves Maintenance

As a best practice, approximately 20 percent of the secondary valves in Idaho, Oregon, and Washington should be maintained to ensure operability each calendar year. Secondary valves within the entire gas system should be maintained in a 5-year period, not to exceed 63 months.

Recordkeeping

Valve maintenance information shall be recorded on the appropriate valve inspection and maintenance record. These forms become a permanent record of valve maintenance performed and shall be retained for the life of the facility. Records may be electronic or paper format and shall be available to the local Construction Office.

Emergency Valves and Emergency Curb Valves should be identified on the card or electronic record.

PLUG VALVE LUBRICATION PROCEDURES:

Consult manufacturer's installation and maintenance instructions before performing valve lubrication or maintenance. Manufacturer's instructions will normally have detailed procedures for troubleshooting, maintaining, and repairing a specific valve. Contact Gas Engineering for assistance in locating manuals when required.

There are normally two methods used to lubricate the plug valves. Lubricant sticks may be manually injected into the valve, or a pressure gun (Rockwell 400C, VAL-TEX, or similar) may be employed to inject lubricant into the valve under pressure.

Most buried valves will require the use of the handgun as it simplifies the lubrication procedure.

Manual Injection

To inject lubricant (sealant) manually:

1. Assure valve is in the full open or full closed position.

2. Remove the Rockwell lubrication fitting or lubricant screw.

3. Insert the appropriate sealant from the tube or choose the correct size stick and place it into the stem.

4. Replace the fitting and screw it down with a wrench until the sealant system is filled completely. This is determined by the resistance produced by the sealant pressure. Larger valves will require several sticks or tubes of sealant.

5. Add sealant and screw down the fitting until sealant back pressure builds up, making the fitting hard to turn. Then continue to add sealant until the plug lifts (sometimes with a hissing sound) and relieves itself indicating that the system is full. Stop adding sealant and operate the valve. If the plug does not turn easily, add sealant until it is free or consult the manufacturer's instructions.

Sealant Gun

To inject sealant with the Rockwell 400C, VAL-TEX, or similar sealant gun:

1. Assure valve is in the full open or full closed position.

2. Insert proper lubricant/sealant into the gun. Check that there is sufficient hydraulic fluid in the gun reservoir. (Refer to manufacturer's instructions for procedures).

3. Fit the gun's button head coupler over the lubrication fitting on the valve. Start the coupler onto the fitting until the fitting head stops at the check valve (approx. halfway).

4. Lift up gently on the back end of the coupler and pull the coupler onto the fitting with a gentle sliding movement.

5. Inject sealant by pumping the gun as long as the needle on the pressure gauge climbs steadily. At some high pressure point on the gauge, the needle will drop back when the plug un-seats indicating a fully pressurized system. This point can also be felt when the pumping effort falls off. Additional pumping will not hold the gauge needle and injecting should be stopped at this point. The plug should then be turned to check the ease of operation. Additional sealant can then be injected, if needed.

6. If the valve will not hold internal pressure and the needle on the gun's gauge falls to line pressure after each stroke, consult the valve instruction manual. If the needle on the gauge pumps up into the red zone, then bypasses, there may be a restriction in the valve, or the gun may need repair. The manufacturer's instruction manual should be consulted in trouble shooting valve or gun problems.

7. Put a dab of sealant on the top portion of the Rockwell fitting to prevent corrosion after the lubrication procedure is completed.

SERVICE VALVE LUBRICATION PROCEDURES:

Consult manufacturer's installation and maintenance instructions before performing service valve lubrication or maintenance.

5.14 CATHODIC PROTECTION MAINTENANCE

SCOPE:

To establish uniform procedures for the monitoring of metallic pipelines for external and internal corrosion.

REGULATORY REQUIREMENTS:

§192.451, §192.491, §192 Appendix D

WAC 480-93-110, 480-93-115, 480-93-188(3)(d)

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design – Steel
Spec. 2.22, Meter Design
Spec. 2.32, Cathodic Protection Design
Spec. 3.42, Casing and Conduit Installation
Spec. 3.12, Pipe Installation - Steel
Spec. 3.32, Repair for Steel Pipe
Spec. 3.44, Exposed Pipe Evaluation

CATHODIC PROTECTION MONITORING

General

Cathodic protection (CP) monitoring and repair shall only be performed by properly trained and qualified personnel. As a minimum qualification, Cathodic Protection Technicians will be NACE Level 1 Certified, or in the process of working to obtain this certification and working under the direction of a NACE Level 2 or greater Certified Technician, or a Cathodic Protection Specialist. Special conditions in which CP is ineffective or only partially effective sometimes exist. Deviation from this specification might be warranted in specific situations provided that corrosion control personnel in responsible charge demonstrate that the objectives of reference standards are being achieved.

Cathodic Protection Criteria

External corrosion control of steel pipelines can be achieved at various levels of cathodic polarization depending on the environmental conditions. However, in order to demonstrate that adequate cathodic protection (CP) has been achieved, one or more of the following shall apply:

1. A negative (cathodic) voltage potential of at least 850 mV (-0.850 mV) with the CP applied. The potential is measured with respect to a saturated copper/copper sulfate reference electrode contacting the electrolyte. Voltage drops (IR drops) other than those across the structure-to-electrolyte boundary must be considered for valid interpretation of this voltage measurement.

2. A minimum negative polarized potential of at least 850 mV relative to a saturated copper/copper sulfate reference electrode.

3. A minimum of 100 mV of cathodic polarization between the structure surface and a stable reference electrode contacting the electrolyte. The formation or decay of polarization can be measured to satisfy this criterion.

Monitoring Cathodic Protection Areas

Each cathodic protection area or system must be tested at least once each calendar year, but with intervals not exceeding 15 months to determine if the requirements are met. Each system shall maintain a level of cathodic protection as to not cause damage to the coating system or pipeline. The level of protection should not exceed -1.200 VDC “Instant Off Potential” in reference to a CSE (CuCuSO4) reference electrode. Each system or area must have sufficient enough test stations/locations to determine that the overall system or area has adequate levels of cathodic protection.

Monitoring Isolated Main Less than 100ft or Service Lines

For separately protected short sections of pipe not in excess of 100 feet or separately protected service lines, risers, and isolated steel valves within PE service areas these isolated sections of steel may be surveyed on a sample basis. At least 10 percent of these protected structures, distributed over the entire system, must be surveyed, or replaced each calendar year, with a different 10 percent checked each subsequent year, so the entire system is tested in a 10-year period.

MONITORING RECTIFIERS

General

Before performing rectifier maintenance, the Cathodic Protection Technician must first verify that no electric shock hazard exists, (such as “touch potential hazard”), by utilizing a multi-meter or inductive AC gauge to measure AC activity on the rectifier case.

Bi-monthly Rectifier Monitoring

Each CP rectifier or impressed current power supply must be inspected six times each calendar year, but with intervals not exceeding 2-1/2 months to ensure it is operating as required.

The following data is required during a bi-monthly inspection:

1. Tap Settings*
2. Voltage Read
3. Amp Read
4. Name of CP Technician
5. Date

*The tap settings are not required for rectifiers with remote monitoring systems.

At least once per year, each CP rectifier or impressed current power supply must be visually inspected for physical damage or deficiencies, such as rectifier damage, blown fuses, wire deterioration, and missing red color coding on anode wires.

<u>Voltage Reads</u>:
Unless relayed by a remote monitoring system, the voltage at the rectifier shall be taken by using an Avista approved multi-meter by the following method. Connect the common or (-) lead of the multimeter to the structure or (-) output lug of the rectifier. Connect the volt or (+) lead of the multimeter to the anode or (+) output lug of the rectifier. Select the DC volts on the multimeter and record the volt reading as shown on the meter.

Amp Reads:
Unless relayed by a remote monitoring system, the current output of the rectifier shall be determined by utilizing the shunt located on the inside of the front panel and calculated using one of the two following methods:

1. Ohm's Law:

Find the rating of the shunt, (i.e., 15 amp, 50 mV). Using the multi-meter, take, and record the mV read across the shunt terminals. Using Ohm's Law, calculate the current output.

Ohm's Law: $V = IR$ or $I = \frac{V}{R}$

Where: V (volts) = mV X 0.001
I = amps
R = ohms = V/I= volts/amps

Example: Shunt rating of 15 amps, 50 mV with a measured voltage drop across the shunt of 35 mV (convert millivolts to volts by multiplying millivolts by 0.001).

A. R = (50mV X 0.001)/15amps= 0.00333 ohms
B. V = 35mV X 0.001 = 0.035 V
C. I = V/R = 0.035V/.00333 (ohms) = $I_{(current\ out)}$ 10.51 Amps

2. Calibration Factor:

This is Ohm's Law stated in another way. Using the rating of the shunt, determine the "calibration factor" by dividing the amps by the mV. Multiple the voltage reading measured across the shunt in millivolts by this calibration factor to determine the current output of the rectifier.

Example: Using the same information from the example above:

Calibration Factor = Shunt Rating = amps/mV = 15/50 = 0.3 (in this example)

Current Output = I = 0.3 X 35 = 10.5 amps

Detecting Stray Current

Cathodic Interference: When a voltage gradient overlaps a foreign structure and is negative with respect to remote earth, it promotes current discharge from the foreign structure in the area of influence.

Anodic Interference: If a foreign structure crosses a voltage gradient that is positive with respect to the remote earth. It promotes current pick-up within the area of influence and current discharge outside the area of influence. Current span testing is a method that can be used to test for stray current.

Interference problems are individual in nature, resolving interference problems can be mitigated utilizing one of the following methods:

- Removal of detrimental effects of interfering current by installing a metallic path.
- Counteracting the effect by applying cathodic current
- Removal of the interfering current source
- Coating or shielding at current pick-up points
- Resistance bond with foreign cathodic structure

Monitoring Critical Bonds and Diodes

Each reverse current switch, each diode, and each interference bond whose failure would jeopardize Avista's cathodic protection system must be checked at least six times each calendar year, but with intervals not exceeding 2-1/2 months. Other interference bonds or diodes that are considered non-critical must be checked at least once each calendar year not to exceed 15 months.

Monitoring Steel in Steel Casings

Underground steel casing installations with steel carrier pipe shall be tested at least once each calendar year, not to exceed 15 months, to determine that the casing is electrically insulated from the carrier pipe and the carrier pipe is cathodically protected.

Potential measurements will be made with the reference electrode in a single location as determined by the Cathodic Protection Technician. Refer to the Pipe-to-Soil Procedures at the end of this specification.

A shorted casing may exist if a potential difference of less than 10 mV exists between the casing and the carrier pipe. CP current sources must be off when taking the potential read. If all sources cannot be turned off, any potential within 100mV between casing and pipe will require additional testing.

New casings require test leads connected to the pipe and casing per Specification 2.32, Cathodic Protection Design. Any existing casing without test leads will be retrofitted with test leads unless installation is infeasible.

If there are no tests leads or close contact points, the procedure outlined at the end of this specification should be utilized to determine if the casing is shorted.

CATHODIC PROTECTION MAINTENANCE:

Facilities Under Restoration of Cathodic Protection

When facilities under cathodic protection are found with pipe-to-soil (P/S) potentials below adequate levels, the facilities must be scheduled for restoration. Areas shall be restored within 90 days from the date they are found below adequate levels of protection in Washington and should be restored within 90 days in Idaho and Oregon as a best management practice. An additional 30 days may be allowed in all states for remedial action if there are circumstances beyond Avista's control. Remedial action must have started in a timely manner with an effort to complete remedial within the 90-day timeframe. Examples of extenuating circumstances are permitting issues, the availability of repair materials, and unusually long investigation/repair requirements.

WAC 480-93-110(2): Each gas pipeline company must complete remedial action within ninety days to correct any cathodic protection deficiencies known and indicated by any test, survey, or inspection. An additional thirty days may be allowed for remedial action if due to circumstances beyond the gas pipeline company's control the company cannot complete remedial action within ninety days. Each gas pipeline company must be able to provide documentation to the commission indicating that remedial action was started in a timely manner and that all efforts were made to complete remedial action within ninety days.

Shorted Casings

If testing indicates that there is a possible shorted casing, the following actions, or equivalent actions, developed by Gas Engineering should be employed:

- Clear the metallic contact, if possible, through a construction method that will resolve the problem.
- If metallic contact is not cleared immediately, schedule the possible shorted condition for a follow-up inspection within 90 days to confirm the short still exists. (Note: this is accomplished immediately following discovery of a potentially shorted casing by the Cathodic Technician by performing a battery test, a diode test, or a casing isolation tester analysis. Documenting the completion of this follow-up inspection should be accomplished on an applicable Cathodic Protection Workorder.)
- Leak survey within 90 days of confirmed shorted condition.
- Fill the annular space with a high dielectric casing filler or other material, which provides a corrosion-inhibiting environment.
- If the above options are impractical and the risk of corrosion is minimized by conditions including the location, pipe condition, risk of overpressure, and safety considerations, the casing can be monitored by leak survey. A leak survey must be performed on an ongoing basis at least twice annually but not to exceed 7-1/2 months between leak surveys with leak detection equipment until either of the above options becomes practical or conditions change which render this option inadequate to minimize the risk of corrosion.

Electrical Shorts

Electrical shorts affecting a cathodic protection system (i.e., non-insulated meter set, crossed insulator, etc.) shall be located, and repaired as necessary.

Whenever exposed, underground Dresser-style or other steel mechanical compression fittings shall be cut out or canned (barreled). A Cathodic Protection Technician shall be contacted to verify that the fitting is not being used as an isolation point. Cutting out or barreling may inadvertently create a problem between two separated cathodic protection systems so additional steps may be necessary before removing or barreling the fitting.

Isolated Steel

When isolated sections of steel piping (including isolated steel services/risers) are found, they shall be cathodically protected within 90 days from the date they are found barring extenuating circumstances. These sections must then be reported to the respective Compliance Technician, the Cathodic Protection Foreman, and to the Gas Isolated Steel Project Manager as applicable to be monitored and evaluated for further action.

WAC 480-93-188(3)(d): In the state of Washington, isolated sections of steel pipe that are not cathodically protected within 90 days from being found must be leak surveyed twice each calendar year, not exceeding 7-1/2 months until properly protected.

Isolated Steel Risers

Isolated steel risers shall be replaced with new anodeless steel risers or protected with the appropriate size and type of anode as specified by the Cathodic Protection Technician. If an anode is utilized, it shall be placed on the isolated service monitoring list and replaced within 1 year of discovery.

Isolated Steel Services

Isolated steel services shall be replaced from the main to the meter and a new anodeless riser shall be installed. Dresser fittings found on isolated steel services shall not be bonded across or barreled. Neither shall they be removed and replaced with steel. If a Dresser fitting is found on the isolated service, the entire isolated steel service should be replaced with new pipe. Refer to Specification 2.32, Cathodic Protection Design, "Replacing Steel Services" for guidance on converting steel services to PE services.

Examining Buried Steel Pipe and Coating

Whenever a buried steel pipeline is exposed, it must be examined for evidence of external corrosion and coating deterioration. Refer to Specification 3.44, Exposed Pipe Evaluation.

Repair and Wrapping of Pipe

If external corrosion is found, replacement must be made to the extent required. Refer to Specification 3.32, Repair for Steel Pipe, or consult Gas Engineering for proper repair of corroded pipe. Pipe exposed for examination and/or repair must be cleaned and recoated. Refer to Specification 3.12, Pipe Installation – Steel Mains, for requirements on coating pipe.

INTERNAL CORROSION CONTROL:

Examining Internal Pipe

When steel pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion (rust or pitting) and if the inside wall is clean, dirty, or oily, and if there are puddles of water or oil, or black smudge in the pipe. If pitting is found, it shall be measured with a pit gauge and the depth and width of the pitting shall be noted in the appropriate section of the Exposed Piping Inspection Report form. Refer to Specification 3.44, Exposed Pipe Evaluation. If internal corrosion is found:

- When internal corrosion is found and it extends beyond what is exposed, the adjacent internal pipe must also be exposed and investigated to determine the extent to which internal corrosion exists.
- Replacement must be made to the extent required. Refer to Specification 3.32, Repair for Steel Pipe, or consult Gas Engineering for proper repair of corroded pipe.
- Steps must be taken to minimize the cause of the internal corrosion such as use of a corrosion inhibitor.

Corrosion cells formed on the internal surfaces of pipelines are confined to the internal metal surface and electrolyte and function completely independent from external cells. Scale formations, such as calcium and magnesium carbonates and adherent corrosion products on metal surfaces are important in the internal corrosion process. The beneficial effects of the scale and oxide, which act as protective coatings, are dependent upon their formation, thickness, grain structure, and adherence.

Cavitation and impingement are common forms of corrosion in fluid systems in and near pumps. The hammer-like effect of collapsing entrained gas or air bubbles breaks through protective films or oxides. Turbulent flow created by constrictions or by rapid changes in direction of flow and excessive velocities also removes the protective films formed. When the oxide and scale are repeatedly removed, there is no normal reduction of the corrosion process. Cavitation and impingement produce a characteristically pitted surface at selective locations and is accelerated by the presence of oxygen, carbon dioxide, and hydrogen sulfide. When entrained solids such as dirt and sand are present, a combination of erosion-corrosion can take place.

CP Equipment Accuracy Check

Voltmeters and electrodes used for cathodic protection shall be tested and documented for accuracy annually.

ELECTRODES - Electrodes shall be checked for accuracy by preparing a new electrode which is the standard electrode to be compared against. This electrode should not be used in the field. Set LC-4 voltmeter to DC voltage scale to 200 mv and input impedance to 200 as well. Attach the standard reference electrode to the negative side of the meter and electrode to be tested to the positive DC side. Place the two electrodes end to end, contacting each plug assembly. If the electrodes are evenly matched, the LC-4 voltmeter should read zero. The difference between the two should have a reading of no more than +/- 10mV. If results are out of tolerance, the electrode should be rejuvenated per manufacturer's recommendations.

VOLTMETERS – Voltmeter shall be checked for accuracy using the Tinker and Rasor VC-1 Verifier and procedure. The tolerance level of the voltmeter should be +/- 0.05 V.

Connect the voltmeter to be tested to the Verifier terminals labeled "Positive" and "Negative", observe polarity. Turn the "Voltage Select" knob on the Verifier to the position marked 1.0v. Display on the voltmeter under test will read 1.000 +/-0.002 volts.

Continue to turn the "Voltage Select" knob to the 1.5v and 2.0v positions. In each case, the voltmeter under test will read the selected voltage within +/-0.05 volts. To test the polarity indicator on the voltmeter under test, reverse the positive and negative leads connected to the voltmeter. The voltmeter should display a minus (-) sign, and the voltage selected on the "Voltage Select" knob of the Verifier. If the voltmeter is out of tolerance, it shall be repaired or replaced.

MAINTENANCE AND REMEDIATION TIMEFRAMES AND FREQUENCIES:

Monitoring Function	**Frequency**
Cathodically Protect New Steel Pipelines	Within 12 months of installation (WA not to exceed 90 days)
Testing of Cathodic Protection Areas and Isolated Sections Greater than 100 Ft. (Note: If such isolated sections of steel reside within a casing, they only need to be visited once per calendar year not to exceed fifteen months and this will satisfy both inspection requirements.)	Once each calendar year (Not to exceed 15 months)
Testing of Isolated Sections of Main Less Than 100 Ft., or Isolated Services/Risers	10 percent Sample Annually, (entire system sampled in 10-year period)
Cathodic Protection Rectifiers	6 times per year (Not to exceed 2-1/2 months)
Testing of Critical Interference Bonds, Reverse Current Switches, Diodes	6 times per year (Not to exceed 2-1/2 months)
Testing of Other Interference Bonds	Once each calendar year (Not to exceed 15 months)

Monitoring Function	Frequency
Testing of Steel Casings with Steel Carrier Pipe (Note: If such steel in steel casings are also an isolated section of steel greater than 100 feet in length, they only need to be visited once per calendar year not to exceed fifteen months and this will satisfy both inspection requirements.)	Once each calendar year (Not to exceed 15 months)
Leak Survey of Isolated Steel Pipe Not Cathodically Protected	Two times per year (Not to exceed 8 months) (State of Washington only)
External Surface, Steel Buried Piping - Visual Inspection	Whenever buried piping is exposed
Internal Surface, Steel Buried Piping Visual Inspection	When pipe cut apart or coupon removed

Construction/Repair Function	Repair/Remediation Completion By
Existing Cathodic Protection Areas Where Protection is Inadequate	90 days from date of discovery (WA requirement and a best practice in Oregon and Idaho). If extenuating circumstances exist, another 30 days to restore to adequate level of CP may be granted.
Cathodically Protect Isolated Steel Sections of Piping (including services and risers)	90 days from date of discovery, conduct leak survey and then leak survey 2 times per year. (Not to exceed 7-1/2 months (Cathodically Protect))
Possible Shorted Casings	90 days from date of discovery conduct a follow-up test to confirm the shorted condition.
Confirmed Shorted Casings	90 days from date of discovery leak survey (or repair) and continue leak survey thereafter two times per year (Not to exceed 7-1/2 months)
Existing Cathodic Protection Areas Where Protection is Inadequate	If extenuating circumstances allow another 30 days to restore to adequate level of CP.

Recordkeeping

Cathodic protection maintenance records shall be retained for as long as the pipeline or facility remains in service.

Records and/or maps showing the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system shall also be maintained.

STRUCTURE-TO-ELECTROLYE POTENTIAL (PIPE-TO-SOIL POTENTIAL)

General

A structure-to-electrolyte potential is the voltage difference between the surface of a buried metallic structure (pipe or other metallic pipeline component) and the electrolyte (soil) measured with reference to an electrode in contact with the electrolyte. (Examples of structures include steel gas pipelines, service risers, regulator station risers, casing vents, tracer wires, test stations, etc.)

Potential Test Equipment

The approved equipment for taking structure-to-electrolyte potentials includes a high input impedance voltmeter in conjunction with a copper/copper sulfate reference electrode.

The common or (-) lead of the multi-meter will be connected to the reference electrode. The volt or (+) lead will be connected to the structure being protected by CP current. A negative potential should be indicated on the meter in this configuration. IF A POSITIVE POTENTIAL READING IS INDICATED, CONTACT A CATHODIC PROTECTION TECHNICIAN OR SPECIALIST IMMEDIATELY.

Potential Requirements

Each potential will have the following information recorded:

- Magnitude of potential reading
- Polarity of the reading (+ or -)
- Date of reading
- Name of person taking the reading
- ON and OFF potential reads (Note: Off reads are not required on exposed pipe evaluations)

Maintenance of Equipment

Reference Electrode:

- Verify that the copper/copper sulfate electrode's solution is at an adequate level (1/2 - 3/4 full)
- Verify solution is clear, not cloudy. If cloudy, contact a Cathodic Protection Technician to replace the solution and recalibrate.
- The porous plug should be kept clean, capped, and stored in a vertical position to prevent from drying out.

Multi-meter:

- Store in a dry, moisture-free location
- Replace batteries as needed per manufacturer's instructions.

Test Leads:

- Check for broken leads. Broken test leads will cause a potential reading to drift. To test for broken test leads, use a 9-volt battery and place the (-) lead of multi-meter on (-) terminal of the battery and the (+) lead to the positive terminal of the battery. The voltage read should be close to 9 V (DC). If read is not steady, the leads may be broken. Contact a CP Technician or CP Specialist if leads are broken.

Calibration and/or Verification of Equipment

Calibration and/or verification of equipment shall be performed annually by a Cathodic Protection Technician. High input impedance multimeters shall have a serial number sticker or plate adhered to them (for ID purposes) and a sticker or label affixed and updated annually during maintenance to enable tracking of the calibration or verification.

Equipment Setup

The reference cell is connected to the negative or common terminal (usually black) of the voltmeter and the lead to the structure to be tested is connected to the positive terminal (usually red). Turn multi-meter to volts DC setting.

Aboveground Potential Reads

Connect the reference cell to the negative or common terminal of the voltmeter or multi-meter. Make sure that the porous plug of the reference cell is in good contact with the soil and is not contacting stones, vegetation, and landscaping plastics. (You may get false readings if the reference cell contacts materials other than soil). If dry or frozen ground is encountered, water may be necessary at the point where you place the electrode in the ground.

If the ground has very dry soil conditions, dig a small hole, such as with a screwdriver and pour an abundant amount of water into the hole. This will help to get a more accurate pipe-to-soil read. If the ground is already wet, this step may not be necessary.

Connect the positive lead of the voltmeter or multi-meter to the structure to be tested, make sure that you are taking a read on the appropriate side of an insulated fitting. When taking a read at surface levels on aboveground facilities, it is best to place the electrode in the ground directly above the underground pipe and at approximately 6 to 12 inches on either side of where the pipe rises out of the ground.

Exposed Pipe Reads

When a steel pipeline is exposed and the coating needs to be repaired, a pipe-to-soil read shall be taken and documented on the Exposed Piping Inspection Report form (Form N-2534). It is best to place the electrode in the soil directly above or at the same level and as close as possible to the soil surrounding the exposed pipe. The closer the electrode is to the soil that contacts the pipe, the more accurate the read will be. (This may not be possible in all cases, so take the read at the closest location that is possible.)

Ensure the porous plug of the reference cell is in good contact with the soil and is not contacting stones, vegetation, and landscaping plastics. (You may get false readings if the reference cell contacts materials other than soil.) If dry or frozen ground is encountered, water may be necessary at the point where you place the electrode in the ground.

If the ground has very dry soil conditions, dig a small hole, such as with a screwdriver and pour an abundant amount of water into the hole. This will help to get a more accurate pipe-to-soil read. If the ground is already wet, this step may not be necessary.

Recordkeeping

Record pipe-to-soil reads and other required information on the Exposed Piping Inspection Report form (Form N-2534) as required in Specification 3.44, Exposed Pipe Evaluation. The local Cathodic Protection Technician will follow up on reads that do not meet the required voltage criteria.

Requesting Assistance

While taking pipe-to-soil reads, if results are questionable, check the equipment to make sure that all equipment is functioning properly. If the problem cannot be resolved, contact your local Cathodic Protection Technician for assistance.

If a pipe-to-soil reading results in a positive voltage potential, a local Cathodic Protection Technician should be contacted immediately. A positive read, if read correctly, will indicate that the cathodic protection system is not functioning properly. This may result in metal loss of the pipe if not corrected immediately.

Monitoring Electrical Isolation of Steel Encased Pipeline

When monitoring electrical isolation of a casing from a steel pipeline, follow the same requirements for aboveground Potential Reads; however, a potential read is taken on the casing vent (or designated test lead) and on the pipeline (or designated test lead) and compared to see if the potential difference between the two indicates isolation if there is more than a 100 mV difference. The electrode shall be placed on the ground directly over the pipeline and near the end of the casing for both reads.

PROCEDURE FOR TESTING A CASING WITHOUT TEST LEADS:

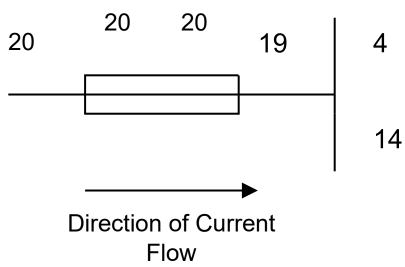
The following procedure is a method for testing for electrical isolation on casings for which there are no test leads or close contact points:

A current source transmitter and receiver (such as a Radio detection Model PDL2 receiver and RD433 HCTX-2 transmitter or equivalent) used in conductive mode is used. The positive output of the transmitter is connected to an electrically continuous portion of the natural gas piping that traverses through the casing, preferably at a distance of at least 100 feet from the casing. The transmitter's negative connection is made to a convenient electrical ground. The transmitter is set to low frequency and low current output. The low frequency and output levels reduce the chance of transmitted current "jumping" to unintended nearby structures.

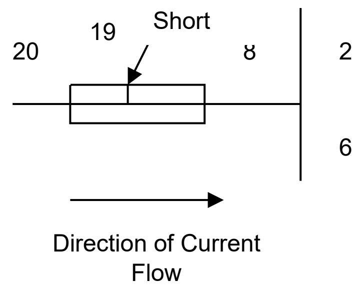
The receiver is then set to the low frequency level and the underground piping route is traced along its path, beyond the suspected location of the casing. Transmitter current output is then measured by the receiver at appropriate locations and recorded on a sketch of the casing and pipe. Current output from the transmitter will travel along the electrically continuous section of the piping. The current will leave the pipe at coating holidays, entering the earth, and returning to the transmitter through the negative connection. Depending upon the transmitter output setting and the coating condition of the pipe, current will travel along the pipe a substantial distance before it is all returned back to the transmitter. The better the coating condition, the longer the distance the current will travel. In the instance of a bare casing shorted to the pipe, much of the current will be returned back to the transmitter along the length of the casing with a substantially reduced percentage of the current continuing on along the pipe.

With a non-shorted casing, the amount of current measured on the downstream side of the pipe just beyond the casing should be nearly the same as the current measured on the upstream portion of the pipe prior to the pipe entering the casing. At locations where the pipe T's, a proportionate amount of the current will travel to each side of the T depending upon the amount and condition of pipe on that particular branch.

Example of Non-shorted Casing:



Example of Shorted Casing:



ALTERNATIVE PROCEDURE FOR TESTING A CASING WITHOUT TEST LEADS:

The following is an approved method of testing for electrical isolation on casings for which there are no test leads or close contact points.

1. A current source transmitter (such as Tinker and Rasor Mark 3 PD short locator equipment or equivalent) is attached to a nearby gas facility and to a ground source.
2. The transmitter output is set to no more than 2 amps and then interrupted. (The set point is based on the distance between the current source and the casing being tested. The closer you are to the casing, the fewer amps that are needed.)
3. The receiver is adjusted to 70 percent sensitivity.
   - The signal produced by the transmitter will only flow toward holidays in the pipe coating or grounded structures in contact with the coated pipe.
   - A shorted casing, which is not coated, shows a huge holiday or ground. The signal is dissipated almost in its entirety by the size of the holiday. Unless the receiver sensitivity is increased, pipe locating is not possible past the casing if it is in a shorted condition. If the casing is determined to be shorted, refer to the “Shorted Casings” of this specification for remedial actions.
   - If no short or contact exists between the casing and the steel carrier pipe, the signal continues past the casing as normal and pipe locating is possible beyond the casing.

The casing length and diameter are not a concern when using this method. Any contact between a coated carrier pipe and a bare casing reacts the same. In addition, the surrounding soil makeup has little or no effect on this type of inspection.

5.15 PIPELINE PATROLLING AND PIPELINE MARKERS

SCOPE:

To establish procedures for patrolling of Avista's gas transmission pipelines and distribution facilities for the purpose of observing conditions that may affect the safety and operation of the lines or other company facilities. This specification also specifies where, when, and in what manner company pipelines and facilities must be marked or identified.

REGULATORY REQUIREMENTS:

§192.603, §192.613, §192.705, §192.707, §192.721, §192.935

WAC 480-93-124

CORRESPONDING STANDARDS:

Spec. 3.15, Trenching and Backfilling
Spec. 4.13, Damage Prevention Program
Spec. 4.16, Class Locations
Spec. 4.31, Operator Qualification
Spec. 5.11, Leak Survey

General

Gas Engineering, Gas Compliance, and local construction offices shall identify transmission lines, high pressure distribution mains, and other distribution lines that may require patrolling or marking under existing regulations. Pipelines that require patrolling include:

- Transmission Lines:
- High Pressure Distribution Mains;
- Intermediate Pressure Distribution Mains and Services (in conjunction with Leak Survey); and
- Any distribution line subject to abnormal movement or external loading which may result in leakage or failure.

Mains in places or on structures where anticipated physical movement or external loading could cause a failure or leakage shall be patrolled four times each calendar year, but at intervals not exceeding 4-1/2 months and documented on Bridge Crossing and Other Piping Quarterly Checklist (Form N-2630). Documentation of conditions found during any patrolling activity should include not only potential safety and integrity issues observed, but also detail as to whether the observed conditions are an immediate concern and what steps are being taken to further investigate and / or resolve the issue.

Included in this category of inspections are exposed facilities that are designed for movement (having expansion loops or joints and otherwise lacking rigid restraint), bridge crossings (regardless of pipeline classification), frost heaving problem areas, and other areas where possible earth movement or land subsidence (including rivers, creeks, and irrigation canals) is a distinct probability. For areas near a gas pipeline where land movement has been identified, further investigation may be warranted to determine whether the pipeline is moving and is under stress. Gas Engineering shall be contacted to determine the appropriate method of investigation and monitoring for the specific situation. For new installations, Gas Engineering and/or local operations managers should determine if the facilities are at risk of physical movement in order to establish a maintenance requirement for patrolling.

Aboveground facilities that are rigidly restrained and are not expected to experience physical movement shall be inspected for atmospheric corrosion every 3 years, not to exceed 39 months. If during this inspection it is noted that the pipe has experienced movement, then the facility shall be identified as an "anticipated movement" facility which shall be inspected four times per calendar year, not exceeding 4-1/2 months.

Employees performing patrolling and marking functions shall be properly trained and qualified. This includes being familiar with the locations of the pipelines being patrolled, locations of other company facilities, locations of bridge, highway and railroad crossings, stream, and river crossings, etc.

Designated buried pipelines shall be patrolled by an appropriate method in order to observe surface conditions on and adjacent to the pipeline right-of-way for indications of leaks (vegetation or leak detector survey), construction or excavation activity, washouts, land subsidence or other earth movement, stream erosion, vegetation management needs and encroachments on the right-of-way by structures, roads, etc. Missing or damaged pipeline markers shall also be identified during patrols and fixed / replaced as applicable.

Designated aboveground pipelines and facilities shall be patrolled in order to observe conditions such as missing supports, broken pipe hangers, active corrosion, damaged or compromised structural barricades, and other integrity concerns. Missing or damaged warning signs shall be identified during patrols and remediated as soon as possible (within 45 days in Washington).

Atmospheric corrosion can occur in many places such as where the pipe penetrates through bridge structures, where the pipe is installed close to the bridge structure, between pipe and hangers / rollers, and in spans over water. If evidence of corrosion is noticed, it shall be noted on the inspection form, Bridge Crossing and Other Piping Quarterly Checklist (Form N-2630), so that it may be referred to Gas Engineering or the local Cathodic Protection Technician for further evaluation as applicable.

For long spans on bridges, binoculars or drones can be used; however, where vision is limited or when the entire pipe span cannot be seen in detail, the inspector may need to get access under the span to be able to observe conditions of the pipe. (If access under the span is a problem for example where boating ramps are closed seasonally, what is visible from the ends or shorelines should be checked quarterly and closer inspections done semi-annually not to exceed 7-1/2 months.)

Methods of Patrolling

Pipeline patrols may be accomplished by either ground (foot or vehicle patrols) or by air (the preferred aerial method is by helicopter but as drone technology improves, this may be an equally good option).

Ground patrols may be performed in conjunction with other work such as leak surveys, valve maintenance, meter inspection and maintenance, etc.

Ground patrols allow for close observation of conditions that may affect company facilities or pipelines. Evidence of gas leakage such as odors and bubbles in surface water can only be adequately detected and assessed on the ground. Other factors such as survey marks (indicating possible future construction), atmospheric corrosion, damaged casing vents and cathodic test points, etc., will also only be readily apparent during a ground patrol.

Aerial (helicopter) patrols are often more effective to cover long distances and/or rugged terrain. Field personnel performing aerial patrolling shall be provided with the appropriate equipment (such as binoculars, aerial maps, etc.) so that the patrol is effective.

Aerial patrols shall be supplemented by ground patrols whenever the pipeline route or any other unusual condition cannot be accurately discerned from the air.

Highway and railroad crossings shall be carefully observed for evidence of leakage during aerial and ground surveys.

Major river crossings under which the pipeline might be subject to scouring, dredging, or other physical damage shall be examined by qualified divers every 5 years, not to exceed 63 months. The diver or remote submergible vehicle shall inspect for signs of leakage (bubbles – Refer to Section 5.11, Leak Survey), exposure, scouring, or any other condition that may affect the safety or integrity of the pipeline.

Other underwater crossings (streams, creeks, etc.) shall be patrolled during the course of the 5-year survey (20 percent leak survey) or during other more frequent patrols as deemed necessary. Refer to Specification 5.11, Leak Survey.

Clearance

The following shall apply to pipeline facilities on Avista owned property or within easements where the terms of the easement allow for such restrictions:

1. No trees are permitted within 10 feet (20-foot clear zone) of an Avista pipeline. The canopy of trees adjacent to easements should not extend into the easement when mature. Branches extending into the easement may be trimmed and side cut by Avista at its discretion.

2. With prior approval from Avista, some types of low growing, shallow-rooted shrubs may be permitted outside 5 feet (10-foot clear zone) of the pipeline centerline. Avista requires that the mature plantings will not prevent Avista personnel or vehicles from accessing the easement for emergency purposes, seeing down the easement during routine patrols, or walking down the easement directly over the pipeline as they perform required inspections. (Note - The intent is to allow shallow rooted plants (shrubs, flowers, etc.) to grow outside of the 10-foot clear zone and deeper-rooted plants/trees may be permitted outside the 20-foot clear zone but vegetation should not block access or visual line of sight). Mechanical equipment shall not be used during the planting of shrubs or other vegetation.

3. Avista reserves the right to cut and/or remove vegetation within the easement as required for safe and efficient access, operation, inspection, and maintenance of its pipeline facilities. Avista will assume no responsibility for the costs associated with the replacement of cut and/or removed landscape plantings that do not meet these criteria.

The following shall apply to pipeline facilities within right-of-way where vegetation restrictions are not within Avista control or within existing easements where the terms of vegetation restriction within the easement are not clearly defined:

1. When vegetation is determined to prevent safe and efficient access, operation, inspection, and maintenance of pipeline facilities or there is potential that tree roots may cause damage to pipe facilities, the property owner or controlling entity shall be contacted to determine if the vegetation can be removed or cut back.

2. In certain cases, Avista may be required to relocate pipeline facilities at its own expense to appropriately mitigate these conflicts.

MAINTENANCE FREQUENCIES

Distribution Line Patrols	**Frequency**
High Pressure Mains (over 60 psig MAOP)	Should occur once each calendar year as a “Best Practice” (Not to exceed 15 months)
Bridge Crossings and lines subject to possible movement	4 Times each calendar year (Not to exceed 4-1/2 months)
Underwater Inspections (major river crossings)	Once every 5 years (Not to exceed 63 months)
Other Distribution Lines (includes stream and creek crossings)	Once every 5 years in conjunction with leak survey

Transmission Line Patrols	**Frequency**
Population Class 1 & 2 Locations	Once each calendar year (Not to exceed 15 months)
Population Class 1 & 2 Locations at Highway and Railroad Crossings	2 Times each calendar year (Not to exceed 7-1/2 months)
Population Class 3 Locations	2 Times each calendar year (Not to exceed 7-1/2 months)
Population Class 3 Locations at Highway and Railroad Crossings	4 Times each calendar year (Not to exceed 4-1/2 months)
Population Class 4 Locations	4 Times each calendar year (Not to exceed 4 1/2 months)
Population Class 4 Locations at Highway and Railroad Crossings	4 Times each calendar year (Not to exceed 4-1/2 months)

Refer to Specification 4.16, Class Locations, for the definition of each population class location in regard to transmission line patrols.

Recordkeeping

Patrols of transmission and distribution lines should be documented on the Gas Patrolling Report (Form N-2629) or otherwise as applicable. This includes aerial as well as ground patrols. Employees performing patrols shall list the conditions found, as well as repairs needed. Required repairs shall be forwarded to the appropriate construction personnel for follow-up action.

Records pertaining to major underwater river crossing inspections shall be retained in Gas Engineering in a file specific to the crossing itself or at the local construction office where the crossing exists. Normally, a dive team or other specialized individual(s) will be contracted to inspect the pipeline and prepare a report of its condition.

Records pertaining to pipeline patrols and inspections shall be retained for the life of the facility.

TIMP – Transmission Patrolling

There are additional patrolling and documentation requirements in regard to Avista's transmission facilities. Excavations near Avista's transmission lines are to be monitored as outlined in Specification 4.13, Damage Prevention Program, "On Site Inspections for Transmission Facilities."

Other requirements are outlined in Avista's Transmission Integrity Management Program, which is a separate document accessible on Avista's intranet website.

PIPELINE MARKERS

Pipeline Markers for Buried Pipe

Pipeline markers may be round, single, double, or tri-faced signs and shall be a distinctive yellow color and written legibly on with a sharply contrasting color. New and existing gas warning and pipeline marker signs shall include the word "Warning", "Caution", or "Danger" followed by the words "Gas Pipeline" in letters at least one inch high with a one-quarter inch stroke. Information posted on the signs or markers must list the current operator (Avista) and a 24-hour telephone number (including the area code). Outdated information on the markers must be updated when found.

Pipeline markers shall be installed and maintained, where practical, over each distribution and transmission pipeline to indicate a potential hazard and/or to designate the location and route of such buried pipelines or underground facilities. Round markers are preferred for new installations of high-pressure gas mains to enhance visibility. Flat or tri-faced markers are typically used for intermediate pressure pipelines. Flat markers should be placed perpendicular to the pipeline. Pipeline marker adhesive stickers may be placed directly on above ground company facilities (e.g., CP Big Finks, CP Small Finks, vent pipes, etc.) where doing so would enhance safety notification.

Pipeline markers shall be placed approximately 500 yards (1500 feet) apart, where practical, and at points of inflection of the pipeline. An effort should be made to place pipeline markers in such a manner that the route of the pipeline is easily discernible and so that the markers are not obscured, to the extent possible, by natural or man-made features. When multiple mains exist in a common right-of-way, each pipeline should be individually marked.

Off-set pipeline markers may be used and should indicate the distance from and direction to the pipeline.

Pipeline markers shall also be placed at the following locations:

- Railroad crossings (both sides if practical);
- Aboveground or suspended pipelines (on both ends if practical) in areas accessible to the public (except service risers, meter set assemblies, and gas pipeline company owned piping downstream of the meter set assembly);
- Public road and highway crossings (both sides if practical); (The exception being public roads or highways in Class 3 or Class 4 areas.)
- Irrigation and drainage ditch crossings (both sides if practical) where hydraulic scouring, dredging, or other activities could pose a risk to the facility;
- Fence lines (In Class 1 / Class 2 areas) where a pipeline crosses private property;
- Stream and river crossings (both sides if practical);
- Any other location where it is determined the pipeline may be subjected to damage (In Class 1 / Class 2 areas)

Exceptions for Marking

Pipeline markers for buried lines are not generally required for mains in Class 3 or 4 locations (refer to Specification 4.16, Class Locations) where placement of a marker is impractical or where a damage prevention program is in effect. Refer to Specification 4.13, Damage Prevention Program.

Washington Pipeline Marker Location Requirements

WAC 480-93-124 - Pipeline Marker Location Requirements

The following pipelines must have pipeline markers installed in Washington:

- Over mains located in Class 1 and 2 locations.
- Over transmission lines in Class 1 and 2 locations, and where practical, over transmission lines in Class 3 and 4 locations.
- On aboveground gas pipelines except service risers, meter set assemblies, and Avista-owned piping downstream of the meter set assembly.
- At both ends of suspended pipelines.

In the state of Washington, the following main and transmission pipelines must have pipeline markers installed regardless of the population class location:

- Where practical, over pipelines operating above 250 psig (this includes Avista's transmission lines).
- At crossings of navigable waterways, on both sides if practical (custom signage may be required to ensure visibility).
- At river, creek, irrigation canal, and drainage ditch crossings where hydraulic scouring, dredging, or other activity could pose a risk to the pipeline. Mark both sides of the crossing if practical (custom signage may be required to ensure visibility).
- At railroad crossings, on both sides if practical. (Note: Additional markers may be warranted within the railroad right-of-way in addition to those typically installed on casing vent pipes, particularly in the case of wide right-of-ways and where the vent pipes are located at the extreme edges of the right-of-way.)
- Where practical, when mains and transmission lines cross interstate highway, U.S. highway, and state highway routes. (Mark both sides of the crossing if possible.)

Vegetation Guidelines

Vegetation shall be controlled so pipeline markers and signage are visible during an inspection or line patrol. If mileage markers are installed along the pipeline, vegetation shall be controlled so that these markers are visible during an aerial inspection of the facility.

Markers for Aboveground Pipelines

Line markers and/or warning signs shall be placed at any point where gas distribution or transmission pipelines are exposed. Markers should not be placed where they are likely to be damaged, destroyed, or where they will interfere with land uses such as cultivation of fields. Markers should not be placed in landscaped areas or areas where the marker may have a negative visual impact without obtaining the permission of the property owner or authority involved. Markers shall not be placed in the right-of-way of a road where they could interfere with or present a hazard to traffic.

Gas pipelines attached to bridges or otherwise spanning an area shall have proper markers or warning signs at both ends of the suspended pipeline. Markers or signs should be installed in the ground at each end of the bridge and stickers / signage directly affixed on the exposed pipeline at both ends near the abutments. These signs / markers shall be kept visible and readable and shall be inspected in conjunction with pipeline patrols. Signs or markers reported damaged or missing shall be replaced as soon as practical. In Washington, this shall be done within 45 days per the requirements of WAC 480-93-124.

District regulator stations, gate stations, farm taps, and block valves shall have warning signs in place.

Washington Pipeline Marker Surveys

WAC 480-93-124 – Survey of Pipeline Markers:

In the state of Washington, a survey of pipeline markers must be conducted every 5 years not to exceed 63 months to ensure they are located where required and are visible and legible.

Markers that are reported damaged or missing must be replaced within 45 days.

Survey records must include a description of the system and area surveyed.

The documented survey record may be maps, drawings, electronic records, or other documents that sufficiently indicate class locations and other areas where pipeline markers are required in the state of Washington.

The documented survey records must be kept for a minimum of 10 years.

5.16 ABANDONMENT OR INACTIVATION OF FACILITIES

SCOPE:

To establish procedures to be used in abandoning Avista's natural gas pipelines and services. Also included are procedures for inactivation of Avista's other gas facilities.

REGULATORY REQUIREMENTS:

§192.727

CORRESPONDING STANDARDS:

Spec. 2.22, Meter Design
Spec. 3.16, Services
Spec. 3.17, Purging
Spec. 5.13, Valve Maintenance
Spec. 5.14, Cathodic Protection Maintenance
Spec. 5.20, Atmospheric Corrosion Control

General

Transmission and distribution pipelines, and services should be abandoned when it is determined they are no longer required for immediate or future use. To enhance public safety and eliminate ongoing maintenance related to inactive above grade facilities, services should be considered for abandonment if they are not expected to be used in the next three years or the service location will substantially change in the future. They shall be disconnected from the pipeline system.

Procedures relating to abandonment of pipelines and facilities and purging operations shall only be performed by properly trained and qualified personnel.

The abandoned pipeline shall be blown down and purged until it is substantially free of gas in accordance with Specification 3.17, Purging Pipelines. If air is used, the employee performing the purging operation shall verify that a combustible gas mixture is not present after purging.

Abandoning Gas Facilities

Pipeline sections to be abandoned in place or that are no longer subject to gas pressure, shall be disconnected from all sources and supplies of gas. The following procedures shall be followed when abandoning gas pipelines:

- Gas Engineering shall be consulted when abandoning pipelines longer than 1,000 feet as additional plugging or sealing points may be required. Segments longer than 1,000 feet should be cut into lengths of 1,000 feet or less. The ends of each section shall be sealed.

- Removal of the pipeline section from the ground or filling the pipeline with solid materials are other options that may be appropriate depending on the circumstances. These options tend to be more costly and normally not needed unless required by local agreements or governing agencies.

- Except as noted in the two paragraphs below, capping of live facilities shall only be by use of fusion/weld caps or approved mechanical fittings.

- For 2-inch and smaller curb tees, curb valve tees and high-pressure service tees operating at 1175 PSIG or less it is acceptable to seal the outlet of the tee during abandonment using a plug or disk cut from steel bar stock provided the following conditions are met:
    - Use a steel plug or disk with minimum thickness based upon the following service tee size:
        - 3/4" service tee/outlet – minimum 1/4" thick
        - >3/4" service tee/outlet – minimum 1/2" thick
    - Use a 1/4" minimum thickness circumferential fillet weld either internally or externally to the outlet of the service tee. If welded externally then the thickness of the disk should be at least 1/4" thicker than the minimum in order to ensure that the minimum thickness shown is maintained on the internal side of the tee and for the welding surface of the parent metal
    - In high pressure retirement applications (MAOP > 60 PSIG) use a minimum Grade B, A36 hot rolled steel bar-stock material with a minimum yield strength of 36,000 PSIG, not to exceed a yield strength of 52,000 PSIG in order to accommodate current existing weld procedures
        - For high pressure facilities use only material that can be tracked via a Material Test Report (MTR). Provide the material Heat # information to Gas Engineering for all high-pressure retirements

- For 2-inch and smaller steel pipe operating at 60 psig or less, where space limitations make it impractical to seal the live end with a fitting, it is permissible to seal the end utilizing a coupon (disk) cut from bar stock. The disk must be at least 1/4-inch thick and fit within the piping so as to be fillet welded circumferentially.

- Pinching the active end of a steel pipe for isolation and abandonment is not an approved method.

- Use of a blind flange as a sealing method of the live facilities is not permitted other than for an above ground application.

- When a cut is required (whether mains or services), a piece of pipe at least 18 inches in length should be removed so that the termination points are as discernible as possible. Excavations shall be backfilled and thoroughly compacted.

- Sections of pipeline that are still in operation shall be inspected for corrosion and coating condition. These conditions shall be documented on the Exposed Piping Inspection Report (Form N-2534). Pipe coating that is removed from pipe that is to remain in service shall be repaired at the conclusion of the sealing procedure.

- When abandoning a lateral (main or service), it should be disconnected as close to the mainline as possible to reduce the potential for future excavation damage. If there is a valve on the lateral to be abandoned, the valve should also be abandoned to eliminate potential underground leaks occurring on the valve stem in the future.

Services to be abandoned in place are subject to the following procedures:

- The preferred method for abandoning a service is to isolate the service using the service tee located at the main, cutting the service line as close as practical to the main, and installing a cap on the active end of the service line.

For 2-inch and smaller steel services operating at 60 psig or less, it is permissible to cut the service line at the outlet of the tee, remove the compression nut from a compression tee, or cut the service pipe as close as practical to the main, and seal the end of the tee or pipe utilizing a coupon (disk) cut from bar stock. The disk must be at least 1/4-inch thick and fit within the service tee or pipe so as to be fillet welded circumferentially. If a Continental compression service tee is used for a PE service off of a steel main, an abandonment cap should be used at the service tee. The open end of the abandoned pipe shall be sealed.

- The service riser shall be removed to below ground level and the remaining pipe sealed. If the service passes through or under a building foundation, the pipe shall be cut outside the building, and both ends sealed.

- Prior to demolition of buildings, services should be disconnected at the main or at a point that will prevent damage to the service. A service found to be supplying a riser without an accompanying building shall be cut off and sealed at or outside the property line as soon as possible after discovery.

The ends of the abandoned pipeline shall be sealed to prevent migration of any foreign gas or other materials through the abandoned line. Sealing shall be done by one of the following methods:

- Crushing or flattening the pipe end and welding the opening
- Welding a plate or a weld cap over the opening
- Using expandable foam insulation
- Utilizing a plastic pipe cap on the OD or plastic plug on the ID. The cap or plug should be sized appropriately for the pipe and be in a satisfactory condition to seal the end of the pipe (i.e., no cuts, cracks, etc.)

Casings

Casings to be abandoned in place shall have their vent pipes and Finks cut off (or entirely removed) below grade. The cut-off ends shall be filled with expandable foam. Carrier pipe within casings shall be abandoned in accordance with the above guidelines for Abandonment of Mains.

Disabling a Curb Valve Tee

When disabling a curb valve tee, the preferred method is the same as discussed above in “Abandoning Gas Facilities”. In addition, a Mueller H-17800 steel abandonment cap should be installed onto the top of tee and seal welded to prevent leakage.

Valve Abandonment

In pipeline systems that are still operational, gas distribution valves and curb valves may be abandoned only if they are not deemed necessary for the safe operation of the gas system involved. Disabled valves (i.e., no longer operational, but gas still runs through it) shall comply with Specification 5.13, Valve Maintenance, “Valve Disable / Abandonment.”

Valve Box Abandonment

When abandoning a valve, the valve box may be removed or, if it cannot be easily removed, it may be abandoned in place by filling the valve box with sand and capping with 4 inches of concrete flush with grade. For a valve that has been ‘Disabled’ per Specification 5.13, Valve Maintenance, a marker ball should be left at the valve prior to making it inaccessible.

Regulator Station Abandonment

Gas piping or other related equipment in regulator and other stations that are no longer in use should be removed in order to minimize hazards.

Vault Abandonment

Each gas regulator vault that is being abandoned shall be filled with suitable compacted material.

Commercially Navigable Waterways

When abandoning a pipeline facility that crosses over, under or through a commercially navigable waterway, a report must be filed by the operator when the facility is abandoned as delineated at §192.727(g)(1).

Inactivating Gas Meter Facilities

When service to a customer is discontinued (shut off or account closed), one of the following procedures must be complied with:

- The valve that is closed to prevent the flow of gas to the customer (service valve) must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by Avista.
- A mechanical device or fitting that will prevent the flow of gas must be installed in the meter assembly (i.e., blank tin disc in meter outlet, blank swivels, plugs, etc.).
- The customer's piping must be physically disconnected from the gas supply and the open ends sealed.
- If the meter set assembly (meter and service regulator) is removed, the service valve shall be locked off and an 8-inch idle riser nipple and cap assembly shall be installed. An approved gas warning sticker (Stock Item Number 662-0426 or 662-0428) shall be applied to the 8-inch nipple and cap assembly to help prevent future damage to the service riser. The outlet swivel shall be removed, and the customer's house piping shall be plugged or capped as appropriate.

Idle Meters and Idle Services

An idle meter is a meter installation on a service where the account is closed. Idle meters shall be removed when it is apparent that gas will not be used in the near future. Local construction offices should investigate customer accounts idle over 12 months to determine if the meter set should be removed.

An idle meter may remain if the customer opens the account and maintains payment of the basic monthly charge.

An idle meter on rental property may remain if the marketing representative determines that another tenant may use the gas in the future. An idle service or riser is where the meter has been removed and the service valve has been locked.

Maintenance Requirements

Maintenance is not required on abandoned pipelines. Idle risers should have idle riser markers with warning signs installed as detailed in “Inactivating Gas Meter Facilities” in this specification. Idle risers and idle meters shall be inspected for atmospheric corrosion and general condition the same as aboveground facilities as outlined in Specification 5.20, Atmospheric Corrosion Control.

5.17 REINSTATING ABANDONED GAS PIPELINES AND FACILITIES

SCOPE:

To establish procedures to be used when reinstating or re-activating abandoned gas pipelines or other gas facilities in Avista's gas systems.

REGULATORY REQUIREMENTS:

§192.725

WAC 480-93-170

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design - Steel
Spec. 2.13, Pipe Design - Plastic
Spec. 3.16, Services
Spec. 3.17, Purging
Spec. 3.18, Pressure Testing
Spec. 3.32, Repair of Steel Pipe
Spec. 3.33, Repair of Plastic (Polyethylene) Pipe

General

Each abandoned or disconnected gas pipeline or other facility must be tested in the same manner as a new gas pipeline or facility before it is reinstated.

Reinstatement or reactivation of gas pipelines and facilities shall only be performed by properly trained and qualified employees.

Reinstating Gas Mains and Services

Each pipeline section that is to be reinstated shall be tested according to the procedures outlined in Specification 3.18, Pressure Testing.

Gas Engineering shall review and approve gas pipelines and facilities prior to reinstatement to verify that reinstating this pipe does not affect the integrity of the system.

Leaks detected through the testing procedure shall be located and corrected (refer to Specification 3.32, Repair of Damaged Pipelines – Steel, and Specification 3.33, Repair of Plastic (Polyethylene) Pipe). Each pipeline shall be re-tested until no pressure drop or leakage is detected.

Each abandoned gas service line disconnected from the main must be tested from the point of disconnect to the meter valve in the same manner as a new service line before reconnecting. Refer to "Reinstating Service" in Specification 3.18, Pressure Testing for additional information.

Steel pipelines exposed for reinstatement shall be examined for corrosion and the existing coating examined before proceeding. Reinstated steel pipelines shall be tied into the existing cathodic protection system and coatings shall be restored where necessary.

Reinstating Gas Facilities

Valves exposed during the reinstatement procedure should be serviced, lubricated, and/or repaired as necessary.

Regulator stations, odorizers, or other facilities shall be brought up to current Company standards before reactivation. Testing and adjustments shall be performed per Company standards.

Insulated, locking meter valves with lubrication ports shall be installed on reinstated services.

Meter set assemblies on reactivated lines shall be built to standard design and/or brought up to Company standards (including relief and bypass capabilities).

No steel service or main that has been disconnected for longer than 90 days may be reinstated without approval from Gas Engineering and the Cathodic Protection General Foreman. Plastic services or mains that have been disconnected for longer than 6 months without being pressurized with air or nitrogen should not be reinstated without approval from Gas Engineering.

5.18 VAULT MAINTENANCE

SCOPE:

To establish an inspection and maintenance program for vaults that house natural gas facilities in Avista's construction areas.

REGULATORY REQUIREMENTS:

§192.749

WAC 296-809

CORRESPONDING STANDARDS:

Spec. 2.42, Vault Design

General

Vaults shall be inspected each time the enclosed facilities are inspected and serviced.

Vault Inspection

Inspection of vaults shall include the following procedures:

- The atmosphere of the vault shall be tested with a Combustible Gas Indicator (CGI). If the vault qualifies as a confined space, the atmosphere shall be tested and monitored in accordance with confined space entry guidelines. (Refer to the Avista Incident Prevention Manual (Safety Handbook), Part 2, Section 16 – Confined/Enclosed Spaces, for additional guidance). Gas leaks discovered shall be repaired.
- The physical condition of the vault must be observed. The walls and roof shall be checked for signs of caving in, crumbling, rusting, or other deterioration. Note the less than adequate conditions found on the Regulator Station Inspection and Maintenance Record (Form N-2527) (paper or electronic as applicable) so that the conditions found may be scheduled for repair as necessary.
- Ventilating appurtenances (as applicable) shall be inspected to determine that they are functioning properly. Check vents, pipes, and floor drains to ensure they are not plugged. Clear or repair as necessary.
- The vault cover shall be checked to make certain that it opens or operates properly, that it is not bent or broken, and that it seats properly. Schedule repairs as needed.

MAINTENANCE FREQUENCY:

Avista's gas distribution vaults shall be inspected and maintained according to the following schedule:

Type	Frequency
Vaults	Once each calendar year (Not to exceed 15 months)

An anniversary date shall be assigned to newly installed vaults. Subsequent maintenance shall be based on the anniversary date established and required maintenance shall be completed before expiration of the grace period. On existing vaults, the last date serviced establishes the anniversary date.

Recordkeeping

Records pertaining to vault maintenance should be recorded on the Regulator Station Inspection and Maintenance Record (Form N-2527), whether on paper or electronic format. Records on vault maintenance shall be retained for the life of the vault.

5.19 COMBUSTIBLE GAS INDICATOR TESTING AND CALIBRATION

SCOPE:

To establish procedures for operation, testing, and calibration of combustible gas indicators used to detect and classify leakage in Avista's pipelines and facilities.

REGULATORY REQUIREMENTS:

§192.706, §192.723
WAC 480-93-186, 480-93-18601, 480-93-187, 480-93-188

CORRESPONDING STANDARDS:

Spec. 5.11, Leak Survey
GESH Section 2, Leak Investigation
GESH Section 4, Emergency Procedures
GESH Section 17, Incident Investigation

General

Combustible gas indicators (CGIs) that are used for leak survey, leak classification, leak centering or pinpointing, or leak detection on customer premises shall be tested and calibrated monthly (12 times a year) not to exceed 45 days. Calibration and maintenance performed on these instruments shall be according to the manufacturer's instructions.

Each instrument used shall be designed to detect natural gas (methane - CH_4) and shall indicate by analog or digital method the percentage gas in an air mixture. Some models also indicate the percentage of Lower Explosive Limit (LEL). The instrument shall be intrinsically safe and rated for operation in a Class I, Division I, Group C, and D atmospheres as defined by the National Electrical Code (NEC).

Instruments calibrated after a gas incident shall have the readings recorded and checked against the previous calibration record to verify a change, if any, in the instruments' performance.

Batteries shall be checked before utilization and changed if the instrument will not zero or if it appears to not be functioning properly.

Test gases shall be used in the concentrations recommended by the equipment manufacturer and shall be certified as accurate within +/- 2 percent of the indicated concentration of methane in air. An appropriate test apparatus such as an "on demand" regulator or equivalent shall be used to provide a sampling atmosphere of the required concentration.

Calibration Procedures

Combustible gas indicators (CGIs) that are used for leak survey, leak classification, leak centering or pinpointing, or leak detection on customer premises shall be calibrated according to the manufacturer's instructions and specific to the docking station (if used) used for each device.

MAINTENANCE FREQUENCIES:

Avista's combustible gas indicators shall be tested and calibrated according to the following schedule:

Instrument	Interval
Bascom Turner (all models) or equivalent	Monthly (12 times a year and not to exceed 45 days) Note: If the CGI has been shipped off for repair and is gone the entire month, it does not need to be calibrated that month.*

*Monthly means every calendar month. A late in the month calibration does not allow waiting the full 45 days and skipping a calibration the next calendar month. An early in the month calibration (ex. the first day of the month) will be out of calibration after the 16th day of the next month.

Recordkeeping

Instrument test and calibration results shall be recorded on the appropriate instrument test form (Form N-2605) and retained in the local construction office (Avista CGIs) and in the respective contractor office (contractor CGIs) for a minimum of 5 years. Electronic copies of the forms should be forwarded via email monthly by the last day of the calendar month to #GasComplianceTechs@avistacorp.com.

5.20 ATMOSPHERIC CORROSION CONTROL

SCOPE:

To establish uniform procedures for the monitoring of metallic pipelines for atmospheric corrosion.

REGULATORY REQUIREMENTS:

§192.479, §192.481, §192.491

WAC 480-93-110

CORRESPONDING STANDARDS:

Spec. 2.12, Pipe Design – Steel
Spec. 2.22, Meter Design
Spec. 3.42, Casing and Conduit Installation
Spec. 3.12, Pipe Installation - Steel
Spec. 3.32, Repair of Steel Pipe
Spec. 3.44, Exposed Pipe Evaluation

ATMOSPHERIC CORROSION CONTROL:

General

Atmospheric Corrosion is the steady and gradual deterioration of the exposed surface of steel by oxidation or chemical reaction with elements of the atmosphere or environment.

Oxidation of metal is the chemical process known as rusting. Rust is the first symptom of atmospheric corrosion. If not treated, it may lead to further deterioration of the pipe depending on local atmospheric conditions. In Avista's service territories, (which are for the most part dry climate environments), a certain level of oxidation that discolors the pipe -- ***without the presence of metal loss*** -- is common and generally does not require immediate remediation as allowed by §192.481. Facilities showing heavy oxidation without metal loss are repaired on an as-needed basis to prevent further deterioration.

Pitting is a severe form of corrosion that occurs when a pipe becomes marked with small indentations, or pits, in its surface. Pitting involves an actual loss in pipe wall thickness. Pitting can be caused by rust or by reaction with other chemicals in the environment that attack the base metal of pipe and fittings.

Causes of Atmospheric Corrosion

Atmospheric corrosion (AC) occurs from exposure to natural forces that attack the base metal and weaken the pipe. It is caused by a chemical reaction between the pipe and its surrounding elements, such as:

- Air
- Moisture (rain, sleet, snow, fog, or condensation)
- Chemicals or pollutants in the environment

Inspection Requirements

Federal Code requires aboveground service piping shall be inspected at least once every 5 years not to exceed 63 months, for evidence of atmospheric corrosion. The inspection can be accomplished by meter readers, gas atmospheric corrosion/leak survey personnel, and other qualified gas field personnel. Most typical aboveground piping includes meter sets and idle risers which are both found on services and applicable to these inspection timeframes.

Single service farm taps, bridge crossings, regulator stations, and aboveground pipelines not susceptible to movement are other examples of pipelines that require an atmospheric corrosion inspection. These inspections occur at the frequencies described in Specification 5.10, Gas Maintenance Timeframes and Matrix, and are completed by other qualified individuals outside of the Atmospheric Corrosion Inspection Program that is administered by Avista's Gas Programs Department. Besides the aboveground piping, other areas of concern to investigate during inspection are as follows:

- Piping/risers at ground surface levels (soil-to-air interface, especially tape wrap)
- Where meters are buried in soil (i.e., meter is in contact with underlying soil and/or landscape materials). This excludes diaphragm meters AL 1400 and larger that are supported on non-combustible material.
- Riser valves or threads that are below grade.
- Where coating is disbonded.
- Under pipe supports, particularly when evidence of corrosion (staining) is apparent.
- Where piping penetrates through bridge structures / deck penetrations.
- In spans over water and splash zones

Additionally, while the atmospheric corrosion inspection is being conducted, other areas of potential concern can be observed that are outside the scope of the requirements of the §192.479 and §192.481 atmospheric corrosion inspections. These include but are not limited to:

- Settling of facilities (Settled)
- Barricades lacking (Protection needed)
- Damage to facilities
- Overbuilds
- Service regulator vents not oriented downward
- Overgrown vegetation
- Other items that may eventually pose a hazard if not corrected

Can't Gain Entry / Can't Find

In the course of performing atmospheric corrosion inspections, survey technicians may encounter situations where they Can't Gain Entry (CGE) to the customer's property (because of a locked gate or an aggressive dog, etc.) or they Can't Find (CF) the gas meter to successfully complete the survey. Specific processes for CGE and CF follow up attempts by the survey contractor are detailed in the Atmospheric Corrosion Orientation Manual (updated annually). If the follow up attempts required by the contractor are unsuccessful a service order is then generated, and Avista Gas Operations completes the survey.

Remediation

Aboveground facilities that require repainting or recoating should have remedial action completed according to the AC Corrective Order Types and Remediation Time Guidelines Table 5 within this Specification.

Facilities reported for metal-loss corrosion shall be followed up to determine the remedial requirements. Refer to Specification 3.32, Repair of Steel Pipe, or consult Gas Engineering for proper repair of corroded pipe.

Sites that bear a light level of oxidation (orange/brown or white discoloration without metal loss) do not require repainting. Sites that show heavy oxidation without metal loss should be repainted, as needed, to prevent further deterioration.

Repainting is accomplished by cleaning the surface with mechanical means such as a wire brush and then applying one coat of industrial grade spray primer/enamel paint. Care must be exercised to perform painting in accordance with manufacturer's instructions, paying attention to guidance on ambient temperature and when it is too cold to perform painting operations. This procedure is suitable for the prevention of atmospheric corrosion.

Aboveground facilities such as bridge crossings that require permits or necessitate special coordination shall be remediated as soon as practical.

For all other concerns found, remedial actions should be completed as indicated in the AC Corrective Order Types and Remediation Time Guidelines Table. Refer to the Program Manager for questions regarding the urgency of questionable situations.

Insufficient Wrap on Steel Risers

The wrap on steel risers must be visible above grade level and be well bonded to the steel riser. If insufficient wrap is discovered, the riser must be excavated down until well bonded wrap can be found / adhered to, and then rewrapped to the above grade level per the requirements in Specification 3.12, Pipe Installation – Steel Mains, "Tape Wrap."

AC Corrective Order Types and Remediation Time Guidelines

Table 1
The order/job types in Table 1 should be completed within 30 days of the inspection date to facilitate meeting future Not to Exceed (NTE) inspection/compliance dates.

Order Type	***Order Routing***
Atmospheric Corrosion – Can't Gain Entry	Service (A071)
Atmospheric Corrosion – Can't Find	Service (A069)
Atmospheric Corrosion – Uninspected (Overbuilt, Overgrown, Debris)	Service (A086)
Atmospheric Corrosion – Damaged Riser	Job (K082)

Table 2
The order/job types in Table 2 shall be completed within 1 year in ID and OR and 90 days in WA.
A best practice in ID and OR is to manage completion of the order to the 90-day WA standard.

Order Type	***Order Routing***
Atmospheric Corrosion – Buried Meter	Service (A080)
Atmospheric Corrosion – Buried Riser	Service (A084)
Atmospheric Corrosion – Buried Riser	Job (K080)
Atmospheric Corrosion – Corroded (metal loss)	Service (A052)
Atmospheric Corrosion – Corroded (metal loss)	Job (K064)

Table 3
The order/job types in Table 3 should be completed end of year following inspection year
(Year 2)

Order Type	***Order Routing***
Atmospheric Corrosion – Needs Wrap	Service (A070)
Atmospheric Corrosion – Riser in Concrete/Needs Wrap	Job (K055)

Table 4
The order/job types in Table 4 are part of the A/C- Continuing Surveillance program. A best practice is to complete these order types end of year preceding next inspection year (Year 3)

Order Type	***Order Routing***
A/C – Continuing Surveillance – Other	Service (A051)
A/C – Continuing Surveillance – Settled	Service (A046)
A/C – Continuing Surveillance – Overgrown	Service (A056)
A/C – Continuing Surveillance – Other	Job (K062)
A/C – Continuing Surveillance – Protection Needed	Job (K054)
A/C – Continuing Surveillance – Overbuilt/Inspected	Job (K051)

Table 5
The order/job types in Table 5 should be completed, as needed, or end of year preceding next inspection year (Year 3)

Order Type	***Order Routing***
Repainting heavily oxidized facilities (without metal loss)	Service

Recordkeeping

Since 2008, the atmospheric corrosion monitoring program records, electronic or paper, are maintained at the Avista corporate headquarters or Jimmy Dean Center. Historical records may be held at each local construction office.

The last two surveys covering a minimum of five years shall be retained. All corrosion repair documentation must be retained for the life of the facility.

Blowing Gas and Odor Calls

For information on recording the appropriate information on blowing gas and odor calls refer to the Gas Emergency and Service Handbook, Section 2 – Leak and Odor Investigation.

5.21 MAINTENANCE OF PRESSURE GAUGES AND RECORDERS

SCOPE:

To establish procedures and specifications for the maintenance and calibration / verification of pressure testing and gauging devices used by Avista's field personnel and contractors.

REGULATORY REQUIREMENTS:

§192.501, §192.503, §192.505, §192.507, §192.509, §192.511, §192.513, §192.515, §192.517, §192.741

WAC 480-93-170

OAR 860-023-0035, OAR 860-023-0040

OTHER REFERENCES:

ANSI B40.1
NEC Article 500

CORRESPONDING STANDARDS:

Spec. 2.22, Meter Design
Spec. 3.18, Pressure Testing
Spec. 5.10, Gas Maintenance Timeframes & Matrix
Spec. 5.12, Regulator and Relief Inspection

General

Pressure gauges and pressure recorders are used to determine existing distribution system pressures, pressure testing of facilities and to assist in making proper adjustments to customer meter sets, district regulator stations, farm taps, and other gas facilities or systems. Only qualified and properly trained individuals shall use pressure gauges or pressure recorders to make determinations or adjustments on Avista's facilities.

Pressure gauges are typically hand held units that are designed to be portable and allow instant checking of pressures. Pressure recorders are designed to be temporarily or permanently installed at a gas meter or facility to provide graphic or electronic documentation of instantaneous pressure of pressure changes over a pre-determined period of time. Both pressure gauges and pressure recorders may be installed by the use of fittings or by the temporary use of "Pete's Plug" style pressure taps.

Applicable personnel have the option of testing (verifying) pressure gauges on a test apparatus (Test Bench) in the construction office or sending the gauges to a certified testing lab. Preference is for the verification to occur at the test bench in the construction office nearest their home base for the cost savings it will afford. Pressure recorders are typically calibrated at the Gas Meter Shops in Spokane or Medford.

Types of Pressure Gauges

Digital Pressure Gauge - Modern digital pressure gauges combine electronic pressure transducers with microprocessors to determine the pressure being measured. Incremental changes in the position of the transducer diaphragm are converted to electrical signals which are processed and displayed on a LCD display. The gauges are normally battery powered.

Minimum display increments (resolution) shall either be in one-tenth (0.1) or one-half (0.5) psig (or inches of water column as applicable) increments.

Some examples of digital pressure gauges being used by Avista are the Crystal XP2i for psig and the UEI EM201B for inches of water column.

If a Crystal digital psig gauge is over pressured beyond 200 percent of its rated pressure range, it is recommended that the gauge be verified to ensure there was not a shift in calibration. Consult other manufacturers for their recommendations regarding over pressurization of their gauges.

The UEI EM201B digital manometer can only tolerate extremely minor over pressures of 2 inches water column (WC) above its 60 inch WC range and damage occurs at 64 inches WC.

Typical operating temperature ranges for digital gauges such as the Crystal XP2i are 14°F to 122°F. The UEI EM201B digital manometer's operating temperature is 32°F to 104°F. Common practice is to keep the gauge in the heated space in a vehicle.

<u>Bourdon Tube Pressure Gauge</u> – Bourdon Tube gauges uses a thin-walled tube that is normally made from a copper alloy (brass) or stainless steel, depending on the application. This tube is called the element. The element is either bent into a semicircle (C-shaped tube) or spirally wound (coiled safety tube). When pressure is applied to the inside of the tube via the pressure port, the pressure tends to make the Bourdon Tube straighten itself, causing the end piece to move upward. The movement of the end piece is transmitted via the link to the movement. The movement converts the linear motion of the end of the Bourdon Tube into rotational movement. The rotational movement is what causes the pointer to indicate the measured pressure.

Accuracy should be to ANSI B40.1 Grade B or better. ANSI B40.1 – 1974 indicates that the permissible error shall not exceed 2 percent of span at any point between 25 percent and 75 percent of span; in the rest of the scale, 3 percent error is permissible. Bourdon Tube gauges shall indicate pressure in minimum 1 psig increments for psig gauges and shall indicate in 1-inch WC increments for inches water column scales.

Bourdon Tube gauges, as well as other mechanical gauges, can be adversely affected by vibration and oscillation.

The normal ambient temperature range for the Bourdon Tube gauges that Avista uses is -4°F to +140°F. The error caused by temperature changes is +0.3 percent or –0.3 percent per 18°F rise or fall, respectively. The reference temperature is 70°F. This means that at the colder end of the temperature range (-4°F), the gauge may have a negative error of approximately 1.23 percent in addition to its normal percent error rating. This fact should be kept in mind when performing inspections and adjustments in cold weather.

Some examples of bourdon tube gauges being used by Avista are those manufactured by Perma-Cal, typically their "Test Gauge" series with 0.25 percent of full scale accuracy.

<u>Spring and Diaphragm Gauges</u> – Spring and diaphragm gauge purchases are not planned in the future as they are being phased out. They often have a user-accessible screwdriver adjust for zeroing the gauge. Some examples of diaphragm gauges being used by Avista are the Ashcroft 0-10 psig or 0-10 inches WC.

Manometers - Water manometers consist of a U-shaped tube that is mounted on a rigid base that is delineated in inches. There is a valve on one end of the tube and an apparatus for connecting to the pressure source on the other tube end. The tube is filled with water so that both sides of the tube line up with the zero mark on the base. As pressure is applied to one end of the tube, the water level changes correspondingly. A reading is taken from both sides and the sum of the readings (the difference between the high side and low side) equals the pressure measurement in “inches of water column” or WC.

Since this is a direct physical measurement, no field calibrations are required aside from verifying the water level is correct. Care must be taken to ensure that the manometer is upright and level before taking the readings.

Electronic manometers combine a very sensitive electronic differential pressure sensor and microprocessor to provide a very accurate (±1 percent of reading) and high resolution (> 0.01”) measurement in inches of water column (WC).

Manometer pressure measurements shall only be used when inspecting or adjusting meter set installations that operate at inches of water column pressure.

Some examples of manometers being used by Avista are the water based Alta-Robbins G211 U-tube and the digital UEI EM201B dual input differential manometer.

Types of Pressure Recorders

Electronic Pressure Recorders - Electronic pressure recorders combine pressure transducers with microprocessors to convert the pressure being recorded into digital information.

Electronic pressure recorders typical temperature operating ranges are -40°F to 150°F with an overall accuracy typically around ±0.50 percent of span. They typically display the current pressure via an LCD display. They may also record case temperature which is fairly close to ambient temperature and other information such as maximum, minimum, and average pressures in their internal memory (audit trail) for downloading to a computer or, when equipped with a modem, telemetering to our PI data historian or SCADA system.

Examples of electronic pressure recorders used by Avista are the Mercury (now Honeywell) model ERX in both portable and fixed versions.

Paper Chart Recorders - Paper chart recorders utilize an ink pen that creates a line on a circular chart, thus indicating pressure with respect to time. A battery powered chart drive moves the circular paper chart according to the timeframe specified (i.e., 1 hour, 24 hour, 7 day, 30 day, etc.). The ink pen is connected to an arm that is attached to an element. Elements may normally be copper bellows (low pressure, up to 30 psig) or a stainless steel helical coil (for pressures over 30 psig). The elements expand or contract as pressure fluctuates thus moving the arm and pen on the chart with a typical accuracy of ±1/2 chart graduation. The elements can normally withstand a 50 percent over-range and still retain accuracy. The recorder is normally connected to the pressure source by a flexible hose and fittings. “Pete’s Plug” style quick check fittings can also be used for connection.

Paper chart recorders are in process of being phased out due to the inherent challenges with older mechanical devices and the paper charts being exposed to the elements and being rendered unreadable.

Calibration/Verification Standard Device

The pressure standard is a high accuracy piece of test equipment that shall be used to verify the accuracy of each construction office test bench gauges. It may also be used for calibration of field instrumentation such as electronic pressure recorders and electronic volume correctors. It reduces pressure from an internal or external high pressure nitrogen cylinder via adjustable regulation and an adjustable chamber to provide a finely adjustable and stable outlet pressure measured by an internal digital pressure gauge. Avista typically utilizes a Condec (previously Eaton) UPC5000 with three pressure ranges such as 2,000/1,000/400 psig or 1000/500/200 psig with an accuracy of 0.05 percent of full scale for the individual range selected.

Test Benches

Test benches are an apparatus where annual verification of company and contractor gauges will take place. Test bench design should be standardized across all applicable construction offices and will have a sufficient number of high accuracy digital gauges to verify most pressure gauges being used by Avista employees and contractors. The annual gauge verification of all pressure gauges will occur at the test bench and will follow a documented process to include entry of essential gauge information in the compliance data repository (Maximo).

Required Gauges by Job Type

Company and contractor personnel have need to use specific gauges based on their job responsibilities. Following is a list of individual job descriptions and the typical minimum complement of pressure gauges that are needed to do that job. (Note: There is not a firm requirement for individuals to purge their inventory of gauges to achieve these minimum inventory values, rather these lists provide Operations Managers and their personnel a reference of typical needs for the various company-wide positions).

Gas Serviceman:

- (1) 0-300 PSIG, Digital
- (1) Water Manometer
- (1) UEI Digital Manometer
- (1) 0-150 PSIG Perma-Cal Gauge
- (1) 0-600 PSIG Perma-Cal Gauge

Pressure Controlman:

- (1) Water Manometer
- (1) 0-300 PSIG, Digital
- (1) 0-1000 PSIG, Digital
- (1) 0-2000 PSIG, Digital
- (1) 0-15 PSIG, Digital
- (2) 0-10” WC (Ashcroft, Yellow Jacket or similar)
- (2) Differential Pressure Gauges

Gas Meterman:

- (2) 0-500 PSIG, Digital
- (1) UEI Digital Manometer
- (1) Water Manometer
- (1) 0-150 PSIG Perma-Cal Gauges

Company Gas Crew:

- (2) 0-150 PSIG Perma-Cal Gauges
- (1) Water Manometer
- (1) UEI Digital Manometer

Contract Gas Crew:

- (2) 0-150 PSIG Perma-Cal Gauges
- (1) Water Manometer
- (1) UEI Digital Manometer

Telemetry Technician:

- (1) Condec (Eaton) Portable Pressure Calibration Unit, UPC 5000
- (1) Crystal XP2i 0-1000 PSIG, Digital
- (1) Fluke 100G Pressure Calibrator
- (1) Fluke 30G Pressure Calibrator

Inspector:

- (1) 0-150 PSIG Perma-Cal Gauges

List of Acceptable Gauges

Following is the current list of recommended gauges for purchase by Company and contractor personnel:

- Perma-Cal "Test" gauges, full scale ranges to 2000 psig, accuracy: 0.25 percent full scale (bourdon tube)

- Crystal XP2i, full scale ranges to 2000 psig, accuracy: 0-20 percent of range: 0.02 percent, 20-100 percent of range: 0.1 percent of reading (digital)

- UEI EM201B for inches of water column (digital)

- Water manometer

- Others as approved by the Gauge Verification Process Owner, Design Manager. (Often as recommended by the Capital Tools Committee)

The Gauge ID and Verification Sticker

Following is the procedure to uniquely identify each pressure gauge and to document the current calibration status of the gauge:

- Each gauge shall have a self-adhesive long life label affixed with Avista's name and the unique Avista gauge ID number. The size should be as small as practical based on label printer capabilities and space on the gauges. Numbering shall follow the convention of a GPG prefix which stands for Gas Pressure Gauge, followed by a 5 digit number. (Example: GPG00171).

- Each gauge shall also have a self-adhesive long-life label (measuring approximately one inch square) affixed to show the verification expiration date and the initials of the person that performed the verification.

Responsibilities by Job Type

Following are the key roles and responsibilities of personnel supporting the gauge calibration and verification program at Avista:

Meter Shop Foreman**:**

- Ensure calibration of the pressure calibration equipment such as the Condec / Eaton pressure calibrators as required in “Maintenance Frequencies” subsection below.
- Coordinate calibration of district test benches by Meter Technicians.
- Be available as a subject matter expert to the Test Bench Lead and Back-up Technicians.

Meter Technician**:**

- Visit each test bench annually, typically during first few weeks of the calendar year, to:
    - Verify each reference pressure gauge on the test bench
    - Document the pressure verifications in Maximo.
    - Affix applicable calibration sticker/label to test bench gauges
    - Train Test Bench Leads and Back-up Technicians
- Be available as a subject matter expert to the Test Bench Lead and Back-up Technicians.

Gauge Verification Process Owner:

- Act as the customer advocate for the gauge verification process by helping collaborate management and stakeholder engagement.
- Work as applicable with management to ensure training, communication, and process execution occurs.
- Facilitate “service level agreements” as applicable to focus efforts to improve the gauge verification process.
- Serve as the primary point of contact for future proposed process changes including gauge inventory change decisions.
- Ensure appropriate creation and maintenance of process documentation. Audit this documentation as applicable.
- Escalate improvements that need to be made to the gauge verification process to applicable management for resolution.
- Collaborate with identified stakeholders to create, track, manage, and review gauge verification metrics for process evaluation and improvement.
- If required, gather a cross-functional team to problem solve, complete root cause analysis, and implement corrective actions.

Operations Managers:

- Designate the Lead and Back-up Gauge Verification Technicians for respective test bench in their office.
- Ensure Test Bench Lead Technician, Back-up Technician, and Responsible Owners of gauges are fulfilling their responsibilities under the program.

Test Bench Gauge Verification Lead Technician:

- Ensure test bench gauges are verified prior to verification of any gauges.
- Verify gauges of personnel / contractors in operations district.
- Ensure gauges have unique identification number affixed via stickers or labels.
- Document applicable information in Maximo.
- Affix applicable date verification sticker to gauges.

Test Bench Gauge Verification Back-up Technician:

- Fulfill the duties of the Test Bench Gauge Verification Lead Technician when that person is not available.

Responsible Owner of the Gauge:

- Ensure annual verification of all assigned gauges is completed as required.
- Take responsible care of assigned gauges.

Test Bench Locations

Test benches are located at the following Avista operations sites:

- Jimmy Dean Center (Dollar Road) in Spokane, Washington
- Coeur d'Alene, Idaho
- Pullman, Washington
- Clarkston, Washington
- La Grande, Oregon
- Roseburg, Oregon
- Medford, Oregon
- Klamath Falls, Oregon

Test Bench Gauge Verification

Annual Test Bench Verification Procedure (i.e., the Test Bench's gauges): The Pressure Calibration Standards (such as the Condec / Eaton UPC5000 or approved equal) shall be sent to the manufacturer or an approved instrumentation calibration facility annually for testing / calibration and documentation including a certificate of calibration. Once calibrated, the Calibration Standard can be used to perform verification of the reference pressure gauges on the Avista Test Benches.

Gas Meter Shop personnel shall visit each test bench and perform a verification of each reference pressure gauge on the test bench. Alternatively, test bench gauges may be sent to an approved calibration vendor. The serial number of the calibration standard device (as applicable) used to verify the test bench gauges shall be noted in the records repository system (Maximo).

Each test bench reference pressure gauge shall be zeroed and then tested at 25, 50, 75, and 100 percent of full scale gauge range. Perform these tests on the ascending pressure to 100 percent and descending pressure back to zero. Acceptable tolerance is +/- 0.25 percent of full scale for the high accuracy digital pressure gauges with a full scale range greater than 15 psig. Pressure gauges with a full scale range of 15 psig or less, shall be compared to a high accuracy digital pressure gauge of equal or better accuracy. Acceptable tolerance is +/- 1.0 percent of full scale.

If a gauge is not within tolerance it will either be calibrated to Avista's acceptable tolerance, or it will be removed from service and replaced by a similar gauge already verified as acceptable.

Maximo information will be updated by Gas Meter Shop personnel to reflect either Pass or Fail for each reference pressure gauge. If a gauge fails, notation should be made as to why it failed and actions taken. (Example: "gauge sent to vendor for repairs" or "gauge retired and removed from service".)

Each verified or calibrated reference pressure gauge shall receive a sticker identifying a one year validation date. Example: a gauge calibrated on 1/4/16 will have a 1/4/17 date on the verification sticker. (Note: The date on the calibration sticker will reflect the "compliance due date" but in actuality, there will still be three months until the grace date has been exceeded and the gauge has gone out of compliance.)

A unique Maximo Identification Number will be created and assigned to each reference pressure gauge by the qualified individual. A sticker will be attached to the gauge showing this unique identifying number. Manufacturer, pressure range, type, pass/fail status, and other pertinent information such as manufacturer's serial number (as applicable) will be determined and recorded in Maximo by the qualified individual.

Field Gauge Verification at Test Benches

Following is the procedure for annual verification of Company and contractor field gauges at the test bench: Pressure gauges held by Company and contractor personnel should be verified once each calendar year not to exceed 15 months at the Avista Test Bench located nearest to their primary work location. Gauges may, however, be tested at any of the test bench locations noted above. Alternatively, test bench gauges may be sent to an approved calibration vendor.

The verification of the pressure gauges shall be performed by trained and qualified individuals who are familiar with the testing apparatus, procedures, and recordkeeping in Maximo. The primary individual responsible for these duties at each site will be the Test Bench Gauge Verification Lead Technician. This person's back-up will be the Test Bench Gauge Verification Back-Up Technician.

Each field pressure gauge shall be zeroed (if manually adjustable, corrected to read as close to zero as possible) and then tested at 25, 50, 75, and 100 percent of full scale gauge range. Perform these tests on the ascending pressure to 100 percent and descending pressure back to zero. Acceptable tolerance is +/- 1 percent of full scale for psig gauges and +/- 5 percent of full scale for inches WC gauges.

If a gauge is not within tolerance it will either be calibrated to Avista's acceptable tolerance, or it will be removed from service and replaced by a similar gauge already verified as acceptable.

Maximo records will be updated to reflect either Pass or Fail for each gauge tested. If a gauge fails, notation should be made as to why it failed and actions taken. (Example: "gauge sent to vendor for repairs" or "gauge retired and removed from service".) Updated information and status shall be made when repairs are completed or retirement of the pressure gauge is decided.

Each calibrated or verified reference pressure gauge shall receive a sticker/label identifying a one year validation date. Example: a gauge calibrated on 1/4/16 will have a 1/4/17 date on the verification sticker. (Note: The date on the calibration sticker will reflect the "compliance due date" but in actuality, there will still be three months until the grace date has been exceeded and the gauge has gone out of compliance.)

A unique Maximo Identification Number will be created and assigned to each pressure gauge by the qualified individual. A sticker will be attached to the gauge showing this unique identifying number. Manufacturer, pressure range, type, pass/fail status and other pertinent information (such as manufacturer's serial number) as applicable will be determined and recorded in Maximo by the qualified individual.

Field Operating Guidelines for Pressure Gauges

Electrically powered portable digital psig gauges shall be rated as "Intrinsically Safe" or suitable for use in Class I Division 1 areas and shall conform to applicable requirements of the National Electric Code (NEC) Article 500 for Hazardous (Classified) Locations or the equivalent. Electronic pressure recorders shall be rated for at least a Class I Division 2 location.

A water manometer or digital low pressure gauge approved by Gas Engineering shall be used on inches water column (WC) meter sets.

Accurate pressure gauges shall be used whenever performing any type of pressure inspections on customer meter installations, district regulator stations, distribution and transmission pipelines, or any other gas facility.

Pressures may be monitored or tested using the following methods of connection:

- "Pete's Plug" type pressure taps;
- Solid pipe fitting connections (pipe fittings shall match pressure rating of the facility being tested);
- Tapered rubber cone (used for inches water column checks only);
- Custom made meter outlet test apparatus.

"Pete's Plug" pressure taps shall have a gasket installed in the seal cap and shall be checked for leakage after testing. Defective taps shall be replaced.

Permanent pressure taps that utilize valves shall also be plugged or capped off when the pressure gauge or recorder is removed.

Pressure gauges or recorders should be installed in a manner as to prevent damage to the gauge or recorder. Recorders should not be placed in areas where there are corrosive chemicals, where there is a high risk of vehicular damage, or where there could be an accumulation of ice or snow.

Pressure gauges and recorders should be properly stored in a protective case (or other means) to prevent damage due to vibration, shock, exposure to the elements, etc.

"Pete's Plug" insertion male probes and other test apparatus orifices shall be inspected periodically to determine if there is a blockage that could affect accurate pressure readings. Any defective fittings or probes shall be replaced.

Protective covers, caps, or inserts shall be replaced in the probe or instrument to prevent damage or entry of foreign materials.

Pressure gauges shall be inspected prior to use for any apparent physical damage and to determine that the pointer or digital display is at zero. Gauges that show signs of physical damage or have been mishandled (dropped) shall be removed from service until a pressure verification can be performed to validate accuracy of the device. If checked and found accurate, it need not be re-tagged with a new date and may continue to be tested on the original cycle.

Gauges that do not read zero shall be removed from service until a pressure verification is performed to validate their accuracy which will include a zero adjustment by test bench personnel during verification. Field adjustment back to zero without test bench full range verification is not acceptable.

Liquid filled pressure gauges that have lost liquid or are damaged shall be replaced. Liquid filled gauges should not be purchased in the future as they are being phased out.

Field Operating Guidelines for Pressure Recorders

Employees shall verify the circular paper chart is of the correct pressure range and that the brand is compatible with the pressure recorder (as applicable). This shall be done prior to setting the recorder.

Batteries shall be checked on the pressure recorder chart drive prior to installation. The batteries are typically replaced annually. The chart drive shall be checked to verify the period selector coincides with the time period required, as well as with the time period indicated on the circular paper chart.

Pressure recorder pens shall be checked for sufficient ink prior to use and typically shall be refilled or replaced.

Pressure recorders shall be transported in a secure manner and shall be protected from damage.

Pressure recorders shall be inspected prior to use for any apparent physical damage and to determine that the pointer or digital display is at zero. Recorders that show signs of physical damage or have been mishandled (dropped) shall be removed from service until a pressure verification can be performed to validate accuracy of the device. If checked and found accurate, it need not be re-tagged with a new date and may continue to be tested on the original cycle.

Employees shall inspect pressure recorder hoses and fittings after installation in order to determine if there are any leaks. Leaks shall be repaired prior to leaving the premises.

MAINTENANCE FREQUENCIES:

Pressure gauges, standards, and pressure recorders shall be calibrated or verified for accuracy according to the following schedule:

Type of Instrument	**Frequency**
Pressure Gauges	Once each calendar year (Not to exceed 15 months)
Pressure Recorders	Once each calendar year(Not to exceed 15 months)
Pressure Calibration Standards	Once each calendar year (Not to exceed 15 months)

Recordkeeping

Verification ***/*** calibration of pressure standards, gauges, and pressure recorders should be first documented at the main test bench workbook in the construction office where used. The applicable information will then be transferred to the electronic data repository (Maximo).

State utility commissions require a calibration / verification sticker or label on the pressure gauge or recorder. Care shall be exercised to ensure that gauge stickers remain affixed to the gauge and in readable condition. Gauges with missing or unreadable calibration stickers shall no longer be used until the sticker is replaced / updated or the gauge is re-verified as applicable.

Pressure gauges, recorders, and calibration standards shall be tagged with the verification expiration date which is subject to the grace periods offered by the definition of timeframes noted in Specification 5.10, Gas Maintenance Timeframes & Matrix.

5.22 HEATER MAINTENANCE

SCOPE:

To establish uniform procedures for maintaining gas line and pilot line heaters to ensure safe and reliable operation.

REGULATORY REQUIREMENTS:

§192.605, §192.739

CORRESPONDING STANDARDS:

None

General

Avista operates two types of gas heaters. “Line Heaters” that heat the entire gas stream and “Pilot Line Heaters” which heat a secondary stream used to operate regulator pilots. Gas heaters are required to prevent external ice buildup on gas piping and/or hydrate formation inside the piping. Ice or hydrates will typically form when the gas temperature is less than 32 degrees F and liquid, or moisture is present. Heaters counter the Joule-Thomson effect that lowers the gas temperature incrementally with a decrease in gas pressure. The Joule-Thomson effect will lower the temperature of natural gas approximately 7 degrees F for every 100 psi reduction in pressure.

Proper operation of heating equipment is important to prevent hydrate and ice buildup which can lead to excessive pipe strain, ground freezing, and improper operation of regulator pilots.

LINE HEATERS

Operation

Line heaters should be operated and maintained in accordance with the manufacturer’s instructions and this specification. Flame management systems should not be modified without concurrence with Gas Engineering.

Avista’s current line heaters are indirect water-glycol fire tube heaters. The gas stream enters the heater through the inlet connection located on the opposite end from the firebox. The gas stream flows back and forth in a serpentine fashion through a pipe coil mounted in the upper half of the unit. The water-glycol bath is heated by a direct fired firebox located in the lower half of the unit. This firebox is heated by feeding a fuel gas stream to the natural draft burners in the firebox. The firebox heats the glycol to approximately 150 -180 degrees F. The water then exchanges heat with the gas passing through the coil in the upper half of the unit.

The gas temperature is controlled by one of two temperature controllers. The first temperature controller measures the glycol/water bath temperature in the line heater. The second controller measures the temperature of the gas in the downstream piping. The temperature controllers will turn on and off the high fire within the firebox of the heater, which in turn warms the glycol and transfers additional heat to the gas stream.

Typical Set Points:

- Glycol/Water bath – 180 degrees F Max
- Downstream gas temperature - 120-140 degrees F
- Regulators – Per manufacturer's instructions

Maintenance

The following items should be checked at the intervals specified.

Maintenance Item	Maintenance Interval	Corrective Action
Leak Inspection	Monthly	Repair any leaking equipment or fittings.
Operation	Monthly	Verify proper set points and unit is operating properly – Adjust as required.
Water/Glycol Level	Monthly	Fill with Water/Glycol 50/50 solution.
Water/Glycol Constituents	Sample Annually or Replace every 3 years	If sampling, make chemistry corrections. Always sample when the heater is hot.
Pilot Safety Test	Annually, not to exceed 15 months	Repair/Adjust.
High Temperature Shutdown Thermostat Test	Annually, not to exceed 15 months	Verify proper operation. Repair/Adjust as necessary.
Flame Arrestor Clean/Inspection	Annually, not to exceed 15 months	Remove cover and blow Air through Flame Cell to clean.
Heating Coil Inspection	10 years	Remove heating coil and inspect for corrosion. Replace if necessary.

Indirect gas fired heaters should be filled with a 50/50 water/glycol solution. The water/glycol solution is the heat transfer medium between the firebox and the line gas. Either Ethylene or Propylene Glycol may be used, although Propylene Glycol should be used in all new installations because of its lower toxicity. The solutions should not be mixed to ensure proper chemical analysis. The preferred solution is Dow Ambitrol NTF 50.

The heat transfer medium should be present in the sight glass. If low, additional fluid consisting of 50/50 water/glycol should be added. The heat transfer medium should be replaced every 3 years or sampled annually to ensure it has the proper level of corrosion inhibitor. Chemistry corrections should be made as indicated by the analysis.

FLUID SAMPLING PROCEDURES:

1) Ensure that the system is warm. The system must be heated to get a representative sample since the heat in the unit allows thermal mixing of the fluid.
2) When acquiring the sample run the fluid until the fluid trapped in the sampling point has been cleared to ensure a representative sample. Protect yourself from the heated fluid.
3) Follow the sampling procedure contained with the kit. Fill the sampling bottle, leaving approximately 1-inch of air space.
4) Sampling kits can be acquired from Dow Chemical at 800-447-4369.

PILOT LINE HEATERS

Avista's existing pilot line heaters are a catalytic style. The pilot line heaters are used to heat the gas that is supplied to pilot regulators. Heating the pilot gas reduces the likelihood of improper pilot regulator operation due to icing or hydrate formation in the pilots. Pilot line heaters are typically used at stations with pressure drops in excess of 250 psig.

Theory of Operation

Catalytic pilot line heaters work on the principle of oxidation with a catalyst which allows the reaction of natural gas to occur at a lower temperature. Under normal conditions, natural gas will not burn unless its temperature has been raised to approximately 1200 degrees F to 1400 degrees F. By forcing the gas to pass through a bed impregnated with a platinum-based catalyst, catalytic heaters cause natural gas to oxidize at approximately 250 degrees F. Once the catalytic heater is initiated, the heat of reaction continues to build and stabilize between 650 degrees F to 900 degrees F.

Operation/Maintenance

Pilot line heaters should be operated and maintained in accordance with the manufacturer's instructions and this specification.

The following items should be checked at the intervals specified:

Maintenance Item	Maintenance Interval	Corrective Action
Leak Inspection	Annually, not to exceed 15 months	Repair any leaking equipment or fittings.
Operation	Annually, not to exceed 15 months	Verify proper regulator set points and unit is operating properly – adjust as required.

Recordkeeping

Maintenance activities for heaters shall be noted on the Heater Inspection and Maintenance Record (Form N-2615), whether paper or electronic, and shall be retained for the life of the facility.

5.23 ODORIZATION EQUIPMENT MAINTENANCE

SCOPE:

To establish uniform procedures for maintaining gas odorization equipment to ensure safe and reliable operation.

REGULATORY REQUIREMENTS:

§192.625, §192.739

WAC 480-93-015

CORRESPONDING STANDARDS:

Spec. 4.18, Odorization Procedures

General

Avista operates three types of odorization equipment. The first type of odorizer is an “Injection Odorizer” which injects odorant into the flowing gas in proportion to the gas flow rate. The second is a “By-Pass Odorizer” that odorizes a portion of the gas stream to a high concentration that is then mixed with the flowing gas to produce an acceptable odorant level. The third is a “Wick Odorizer” that is used on smaller capacity systems or single services and incorporates a wick that odorizes the entire gas stream.
Proper operation of odorization equipment is important to ensure appropriate odorant concentrations and prevent odorant leaks within the odorization facilities.

INJECTION ODORIZERS (YZ Type)

Operation/Maintenance

Injection odorizers should be operated and maintained in accordance with the manufacturer’s instructions and this specification. Odorant systems should not be modified without concurrence with Gas Engineering.

Avista’s current injection odorizers operate by injecting odorant into the main gas stream in proportion to the gas flow rate. The equipment uses a pump to inject the odorant into the gas. A central processor unit controls the operation of the injection system and determines the output of the pump based on a corrected flow control signal from the mainline gas meter.

Typical Set Points:

- Expansion Tank Pressure – 25 psig
- Gas Supply Pressure – 70 psig
- Blanket Gas Pressure – 30 to 35 psig
- Odorant Level – Maximum Capacity 90 Percent Full
- Injection Rate – 0.36-0.72 lbs/MMCF (Adjust as necessary based on odorometer testing)

Note: Variations may occur depending upon operating conditions that may lead to acceptable alternate set points.

Maintenance

The following items should be checked at the intervals specified. Equipment shall be maintained in accordance with manufacturer's recommendations. The manufacturer recommends that the preventative maintenance schedules consider the application of the odorizer. Considerations related to preventative maintenance intervals include weather / environment, the condition of the actuation gas, the odorant, the odorant bulk storage tank, and the pump stroke frequency.

Maintenance Item	Maintenance Interval	Corrective Action
Operation/Leak Inspection	Monthly	Verify proper set points and unit is operating properly. Check system controller for alarms – Adjust as required. Repair any leaking equipment or fittings.
Odorant Level	Monthly	Inspect and fill as necessary.
Bulk and Expansion Tank Operation	Monthly	Inspect expansion tank fluid level and pressure. Service as necessary.
Bulk and Expansion Tank Overflow Protection	Monthly	Inspect expansion tank and overflow protection regulators and relief for proper pressures.
Replace Filters	As needed	Replace as needed the "Bulk Odorant" and "Gas Supply" filters. Replace based on unit operation.
Injection Pump	Monthly	Inspect Pump Oil Level, Fill as necessary.
	Once every calendar year	Inspect and/or Rebuild Injection Pump.
Solenoids	Pump Solenoid - Once every calendar year Verometer Solenoid – Once Every 2 years	Inspect and replace operational solenoids as necessary.
Pneumatic Relay	Once every calendar year	Clean and service pneumatic relay.
Relief Valves	Once every calendar year	Test and service as necessary the "Expansion Tank Low Pressure Relief" and the "Bulk Tank Relief Valve."
Supply Gas Farm Tap Regulator / Relief	Once every calendar year	Inspect and repair gas supply regulator and relief valve as necessary. (Typically, this is a farm tap style regulator and relief.)
Charcoal Scrubber	Inject Pump - Once every calendar year Expansion Tank Overflow – Once every 2 years	Replace as necessary.
Battery	Once every 2 years	Replace system controller battery.
Pneumatic Valve	Once every 2 years	Inspect and/or Replace "Pneumatic Relay Valve".

BY-PASS ODORIZERS

By-pass odorizers are used to odorize medium sized gas systems. The odorizers are typically installed below grade at gate stations.

Theory of Operation

A very small amount of the mainstream natural gas is by-passed through the odorizing unit. The resulting odorant-laden gas is returned to the gas main to mix with the major portion of the gas flow. As the by-passed gas passes through the odorizer it absorbs enough odorant to provide the desired odor intensity for the entire gas stream when the gas is reintroduced with the main gas supply. Typically, a partially closed valve is used to develop the differential pressure required to operate the odorizer and maintain a direct relationship between the volume by-passed and the total volume flowing in the main. Precision Control Valves are used to adjust and accurately control the odorization rate.

Operation/Maintenance

By-pass odorizers should be operated and maintained in accordance with the manufacturer's instructions and this specification.

Typical Set Points:

Differential Pressure: 30-80 inches water column (WC). The following items should be checked at the intervals specified.

Maintenance Item	Maintenance Interval	Corrective Action
Leak Inspection/ Operation	Monthly	Repair any leaking equipment or fittings. Verify unit is operating properly. Adjust or repair as necessary.
Odorant Level	Monthly	Inspect and fill as necessary.

WICK ODORIZERS

Wick odorizers are used to odorize small gas flows or single customers. The odorizers are installed on above grade piping.

Theory of Operation

The entire gas stream flows past an odorant saturated wick that odorizes the gas stream. The wick extends from a reservoir full of odorant to the gas pipeline.

The capillary action of the odorant continuously feeds odorant through the wick system from the reservoir to the gas stream. The concentration of odorant within the gas stream is adjusted by modifying the amount of wick that extends within the flowing gas.

Operation/Maintenance

Wick odorizers should be operated and maintained in accordance with the manufacturer's instructions and this specification.

Typical Set Points:

Adjust wick length as necessary to achieve desired odorant level. The following items should be checked at the intervals specified.

Maintenance Item	Maintenance Interval	Corrective Action
Leak Inspection/ Operation	Monthly	Repair any leaking equipment or fittings. Verify unit is operating properly. Adjust or repair as necessary.
Odorant Level	Monthly	Inspect and fill as necessary.

Odorant Transport

Odorant is transported to the bulk delivery sites by Avista's designated contractor. Avista personnel may transport odorant from these bulk sites in the contractor's sealed containers or in Avista's DOT approved 154-gallon or 500-gallon portable odorant tanks.

When transporting odorant via Avista's DOT approved portable odorant tanks, the vehicle towing the trailers must have a hazardous material certification. In addition, because the trailers weigh over 1000 pounds they must be placarded with "3336" Flammable Liquids, along with the vehicle towing the trailer.

The appropriate Safety Data Sheets (SDS), bill of lading, tank test and inspection report, certificate of registration, and vehicle inspection sheet shall be in the vehicle being used, additionally the bill of lading is good for two years. Drivers of the vehicle must maintain a current CDL with hazmat and tank endorsements. Contact the Avista Safety & Health Department for proper labels and SDS sheets.

Odorant Spills

Odorant spills shall be controlled and corrected immediately. An Avista-approved non-flammable, non-toxic neutralizing agent shall be used.

Ground spills and indoor spills should be sprayed with the neutralizing agent as soon as possible. The chemical will normally begin neutralizing mercaptan-based odorants upon contact. The solution should be mixed according to manufacturer's instructions and can normally be applied using a spray bottle or with a weed type garden sprayer in the case of larger spills. Care should be taken when cleaning spills as a flammable atmosphere may exist as odorant is flammable. The atmosphere in an indoor spill situation should be vented as you would with a natural gas leak.

Parts, equipment, clothing, and personnel may also be de-odorized using various solutions of neutralizing agents. Consult the manufacturer's instructions before applying the agent to avoid possible risks to health. Personal protective equipment (PPE) shall be used when indicated.

Safety and Health Department Notification

The Avista Safety and Health Department shall be notified in all cases in which odorant comes in direct contact with Company personnel. In cases of large spills requiring disposal of contaminated ground, clothing, and other items, company Safety and/or Environmental Coordinators shall be notified through the 24-hour spill pager hotline at 509-998-0996.

Mercaptan based odorants require respiratory, skin, and eye protection, and are listed as Hazardous Materials in the Company SDS reference. Safety and/or Environmental Coordinators shall coordinate the necessary reporting, referral for medical services, and disposal relating to odorants. The SDS data sheets shall be immediately available to the field employee filling or maintaining odorization equipment.

Recordkeeping

A monthly volume odorization report shall be made on the Odorizer Inspection and Maintenance Record (Form N-2621) as necessary for use in planning the re-filling or repair of odorizers. Copies of these records (electronic or paper) shall be retained for a period of 5 years. The following information should be recorded for each odorization station (except for farm tap installations):

- Manufacturer's designation of the odorant used
- Pounds of odorant used

Other maintenance activities for odorizers shall be recorded on the Odorizer Inspection and Maintenance Record (Form N-2621). Copies of these records (electronic or paper) and retained for the life of the facility.