Prepared by: MHC6

PIPING DESIGN AND TEST REQUIREMENTS — A-34

Asset Type: Gas Transmission and Distribution **Function:** Design and Construction

Issued by: Redacted ⟵ Original Signed By **Date:** 03-29-13

Rev. #04: This document replaces Revision #03. For a description of the changes, see Page 12.

Purpose and Scope

This numbered document establishes a uniform procedure for designing and testing gas piping systems that must meet the requirements of Code of Federal Regulation Title 49, Part 192-TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS.

Acronyms

API: American Petroleum Institute
ASTM: American Society for Testing and Materials
BOM: Bill of Material
CFR: *Code of Federal Regulations*
CPSD: California Public Utilities Commission – Consumer Protection and Safety Division
CPUC: California Public Utilities Commission
Company: Pacific Gas & Electric Company
DOT: Department of Transportation
DSAW: double submerged arc welded
DWT: dead weight tester
ERW: electric resistance welded
EW: electric weld
ETS: Electrolysis Test Station
FDP: future design pressure
G.O.: General Order
HFW: High Frequency Weld
MAOP: maximum allowable operating pressure
MOP: maximum operating pressure
OD: outside diameter
psi: pounds per square inch
psig: pounds per square inch gauge
SAW: submerged arc-welded
SAWL: submerged arc-welded Longitudinal
SMLS: seamless
SMYS: specified minimum yield strength
STPR: strength test pressure report

References

References	Document
Gas Standard and Specifications	
Piggable Pipeline	A-05
Pipe Dimensions and Properties	A-10
Identification of Steel Pipe	A-11
Code Numbers for Steel Pipe	A-15
General Requirements Work Reportable to the California Public Utilities Commission	A-34.1
Design and Construction Requirements Gas Lines and Related Facilities	A-36
Hydrostatic Testing Procedure	A-37
Casings for Highway and Railroad Crossings	A-70
Plastic Gas Distribution System Construction and Maintenance	A-93.1
Steel Butt-Welding Fittings	B-20

Piping Design and Test Requirements

References

Document

Manuals

Corrosion Control Volume of the *Gas T&D Manual*
Plastic Volume of the *Gas T&D Manual*

Regulatory Documents

Code of Federal Regulations 49 CFR 191-Transportation of Natural and Other Gas By Pipeline: Annual Reports. Incident Reports, safety Related Condition Reports.
Code of Federal Regulations 49 CFR 192-Transportation of Natural and Other Gas By Pipeline: Minimum Federal Safety Standards.
California Public Utility Commission (CPUC) General Order No. 112-E
CPUC directive dated September 12, 2011 for conducting spike test.
National Electrical Code, ANSI Standard C1 (Latest Edition).

Note

CPUC G.O. 112E, Section 125, requires written and verbal notification of certain work. See Numbered Document A-34.1 for these requirements.

Definitions

The following definitions shall apply to this numbered document:

1. “Abandoned” means permanently removed from service.
2. “Active corrosion” means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.
3. “Class Location” is a geographic area as classified and described in 49 CFR 192 and TD-4127S.
4. “Design Factor” is the percentage of SMYS to which operating stress is limited, as further described in 49 CFR 192.
5. “Distribution line” means a pipeline other than a gathering or transmission line.
6. “Electrical survey” means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.
7. “Future design pressure (FDP)” is the pressure to which proposed and future additions, or changes to existing facilities, are designed and tested.
8. “Gas” means natural gas, flammable gas, or gas which is toxic or corrosive.
9. “Gathering line” means a pipeline that transports gas from a current production facility to a transmission line or main.
10. “High-pressure” distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

PG&E's definition of high-pressure distribution system: a system that operates at a pressure greater than 25 psig, but not greater than 60 psig. Service regulators with the characteristics of listed in 49 CFR 192.197(a) are required on each meter set. (See Utility Procedure TD-4125P-01)

11. "Hoop Stress" is the stress in a pipe wall, acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe, and produced by the pressure of the medium in the pipe.
12. "Leak Test" is a pressure test to determine the tightness of the system.
13. "Line section" means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.
14. "Low-pressure" distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

    PG&E's definition of low-pressure distribution system: a system that operates at a pressure of 3-1/2 inches water column (WC) through 10-1/2 inches WC. Service regulators are not required on each customer meter set (See Utility Procedure TD-4125P-01)
15. "Main" means a distribution line that serves as a common source of supply for more than one service line.

    PG&E's definition of distribution main: a pipeline that serves as a common source of supply for more than two service lines operating at 60 psig or less. PG&E considers a service and a branch or adjoining customer as one service. (See Utility Procedure TD-4125P-01)
16. "Maximum actual operating pressure" means the maximum pressure that occurs during normal operations over a period of 1 year.
17. "Maximum allowable operating pressure (MAOP)" means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

    PG&E's definition of maximum allowable operating pressure (MAOP): the maximum pressure at which a pipeline, pipeline segment, or component is qualified to operate in accordance with the requirements of 49 CFR 192 based on the design pressure of the weakest element in a pipeline system. (See Utility Procedure TD-4125P-01)
18. "MOP" is the maximum pressure at which a system may be operated according to the criteria established in Utility Standard TD-4125S.
19. "Operator" means a person who engages in the transportation of gas.
20. "Person" means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.
21. "Pipe" means any pipe or tubing used in the transportation of gas, including pipe-type holders.
22. "Pipeline" means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.
23. "Pipeline environment" includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.
24. "Pipeline facility" means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.
25. "Service line" means 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 customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

    PG&E's definition of service line: a pipeline that transports gas from a common source of supply to a customer meter set. (See Utility Procedure TD-4125P-01)
26. "Service regulator" means the 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.

27. “Strength Test” is a pressure test to prove the mechanical strength of the system.
28. “Stress” is the resultant internal force per unit area that opposes change in the size or shape of a body that is acted on by external forces.
29. “SMYS” means specified minimum yield strength is:
    A. For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or
    B. For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with 49 CFR192.107(b)

    PG&E’s definition of SMYS: “SMYS” is the minimum yield strength in psi prescribed by the specification under which the pipe is purchased from the manufacturer or as specified in 49 CFR 192.
30. “Spike Test” is a test used at the beginning of a pressure test on **existing** pipelines (uprates, confirming MAOP’s, etc.) to verify the structural integrity of the pipelines with potential time dependent anomalies. The spike test involves subjecting the piping system to a maximum pressure level that is held for a short duration at the beginning of the test followed by a longer duration hold period at a reduced pressure.
31. “Spike Hydrostatic Pressure Factor” is a factor for computing spike hydrostatic test pressure. The spike hydrostatic pressure factor is multiplied by the required minimum test pressure at maximum elevation used to establish MAOP of a pipeline in order to determine the minimum required spike hydrostatic test pressure. The range of spike hydrostatic test pressure factor is: 1.05 (min) to 1.1 (max).
32. “Spike Hydrostatic Pressure Duration” is the desirable target duration for the spike portion of a hydrostatic pressure test: 30 minutes with a minimum acceptable duration of 15 minutes.
33. “Static Head” is the height of a column of water at rest that would produce a given pressure head.
34. “Test Medium” is a substance such as water, air, or gas used to exert an internal pressure to leak or strength test a facility.
35. “Test Pressure” is the pressure of the medium specified for testing.
36. “Transmission line” means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

General Information

Prior to work being performed, the project manager shall develop a list of covered tasks included within the project scope and will check operator qualifications for all covered tasks to ensure assigned personnel are qualified to perform the work.

1. Filing Information

   Revision 04 supersedes any previous instructions which are contrary to the content of this numbered document.

2. Policy and Application

   All new, replaced, and relocated gas pipelines and facilities shall be designed and tested according to the requirements of 49 CFR 192.

3. Responsibility

   A. The Company’s responsible engineer must prepare “Gas Pipeline Facilities Strength Test Pressure Report” (see Attachment F) for each facility designed to support a MAOP of 100 psig or greater. The Company’s engineer must ensure that all applicable information is completed in “Part1 - Design Data.” These reports must accompany the construction documents to the field.

   B. The Company’s supervisor responsible for the facility’s construction must ensure it is tested according to this numbered document. Before testing any facility designed to support a MAOP of 100 psig or greater, the supervisor must verify that “Gas Pipeline Facilities Strength Test Pressure Report,” with “Part I - Design Data” has been completely filled out, signed and is available at the jobsite. The supervisor must also verify that the pipe specifications and footages are correct before proceeding with the test. After finishing the test, the supervisor must complete “Part II - Test Data.

C. The Company's engineer and the construction supervisor are responsible for ensuring that all other applicable provisions of 49 CFR 192 are followed when designing, constructing, and testing a facility.

4. Design

A. General

(1) Design of pipeline and appurtenances, selection of materials, construction and testing shall conform to 49 CFR 192, this numbered document, corrosion manual, plastic manual and referenced documents. Pipe must be designed with sufficient wall thickness or must be installed with adequate protection, to withstand anticipated external pressures and loads that will be imposed on the pipe after installation. Safeguards against probable threats to the pipeline and facilities shall be provided through proper design, construction and operations.

(2) Directional changes in pipeline shall be designed to accommodate safe passage of internal inspection tools e.g. intelligent pigs and video devices per Numbered Document A-05.

(3) Locate gas transmission lines and facilities at a minimum distance of 500 feet from sub-stations as a safeguard against damage from fault currents and induced voltage. If site constraints preclude maintaining the minimum 500 feet distance from sub-stations then contact Corrosion Engineering for solution. Corrosion Engineering will provide design and construction guidance for mitigation against the potential hazards.

(4) Protect all pipelines from washouts, floods, unstable soil, landslides or other hazards. Take adequate measures to prevent pipelines in flood plains against floating due to negative buoyancy by concrete coating per Utility Standard 4130.

(5) Protect above ground pipelines from vehicles or other hazards by placing them at a safe distance from third party threats or by installing barricades.

(6) Pipelines to operate at 30% or more of SMYS which lie in the seismic active zones or across fault lines must be designed to withstand seismic acceleration forces and possible ground liquefaction. These pipelines must have adequate mechanical strength and flexibility to withstand ground movement and acceleration forces of earthquakes. Selection of proper backfill material will be required to inhibit liquefaction. Because of special design requirements the assistance of PG&E's seismic consultants must be sought through Pipeline Engineering.

(7) Pipelines crossing State Highways, Freeways and Railroads must be designed to the requirements of Utility Standard 463-3 and to the permit requirements of agencies having jurisdiction over the crossings. If casing is prescribed in the permit it will be selected and designed per Numbered Document A-70.

(8) Distribution piping design and construction shall be based on Plastic Manual.

B. Corrosion Control

Corrosion control design and construction shall be done per Corrosion Manual.

(1) Steel pipelines must be protected from external corrosion by external coating and cathodic protection by using following standards:

a. Coat above ground steel piping in accordance with Numbered Document E-30.

b. Coat steel piping installed in vaults in accordance with Numbered Document E-30.

c. Coat buried steel piping in accordance with Numbered Document E-35.

d. Provide cathodic protection for buried steel piping in accordance with Numbered Document O-16.

e. Install Electrolysis Test Stations (ETS's) at one mile intervals on buried steel transmission pipelines as described in Numbered Document O-10 and O-10.1. Install a Coupon Test Station (CTS) approximately midway between each set of ETS's in accordance with Numbered Document O-10.2. The spacing interval between ETS's and CTS's can vary to accommodated maintenance requirements. ETS and CTS locations should be chosen to be easily accessible and to provide protection from damage by farming activities, vehicular traffic and erosion.

f. ETS's must be provided for steel distribution piping. The local corrosion mechanic shall determine the number and location of distribution piping ETS's.

g. Electrically isolate steel piping from foreign metal structures.

h. Steel distribution piping must be arranged in electrically isolated cathodic protection areas as described in Numbered Document O-16.

i. Electrically isolate steel compressor station piping from transmission pipeline piping.

j. Electrically isolate steel piping from metal pipe supports.

k. Pipelines situated in close proximity of the tracks of electrically operated trains or high tension overhead electrical transmission lines are susceptible to the “interferences” of pipeline cathodic protection. In those situations contact Corrosion Department for advice.

(2) New transmission lines and replacements to existing transmission lines and/or components must be designed and constructed to reduce the risk of internal corrosion**.** Unless it is impracticable or unnecessary, the following are required for new transmission lines and replacements to existing transmission lines:

a. Configured to reduce the risk that liquids will collect in the line.

b. Equip new installation with effective liquid removal features where liquids could collect, if deemed necessary by Corrosion Engineering.

c. Design must allow use of monitoring devices at locations with significant potential for internal corrosion.

d. Evaluate the internal corrosion risk on downstream sections.

e. All designs must be reviewed and signed by Corrosion Engineering.

C. Pipe Design

(1) A design criteria stamp (see Figure 1) must be completed for each size, specification, grade, seam-type, and wall thickness of pipe shown on Plan and Profile/Sections sheets. A separate design criteria stamp is required for each MAOP to be established and for each test pressure. The FDP and MAOP to be specified on the design criteria stamp are for the pipe segment to be tested.

(2) When determining design requirements to establish the MAOP, consideration must be given to the following:

a. Future development of the area.

b. Current and future gas supply pressures.

c. Probability of increases in supply pressure.

(3) The design formula for steel pipe is given below:

$$P \text{ ffi } \frac{2St}{D} \text{ ffl } F \text{ ffl } E \text{ ffl } T \text{ (according to 49 CFR 192.105)}$$

Where:
- P = maximum allowable design pressure, psig
- S = SMYS, psi, determined according to 49 CFR 192.107
- t = nominal wall thickness, inches, determined according to 49 CFR 192.109
- D = outside diameter, inches
- F = design factor determined according to 49 CFR 192.111
- E = longitudinal joint factor determined according to 49 CFR 192.113
- T = temperature derating factor determined according to 49 CFR 192.115

(4) Pressure ratings for fittings, valves, and other piping components shall be equal to or greater than the design pressure established for the piping system.

(5) Initial Construction

The design of all new gas facilities and any subsequent additions or alterations to existing facilities must meet the expected future class location and, as a minimum, the planned future MAOP requirements of the pipeline. Attachments B and C of this numbered document contain specifications for commercially available pipe commonly used at PG&E. Other sizes and wall thicknesses are available from pipe manufacturers. Consult the Pipeline Engineering for assistance.

(6) Requirements for Pipeline Construction Drawings

Attachment D and Attachment E provide the content, format, technical, and professional engineering review requirements for pipeline plan and profile construction drawings.

(7) Welding: All welding shall be done according to Numbered Document D-22

5. Inspection

A. Welds shall be inspected as required by Numbered Document D-40.

B. Girth welds used to tie in fabricated units and short sections of pipe shall be inspected as required by Numbered Document D-40.

C. Trenches, pipe, and pipe coating shall be inspected as required by Numbered Document A-36.

6. Testing

A. All new, replaced, and relocated gas pipelines and facilities transporting natural gas must be tested according to the requirements of 49 CFR 192. This includes returning to operation any segment of pipeline that has been relocated, replaced or previously abandoned. Except as documented in Notes 2 and 3 to Table A-1 in Attachment A on Page 14, the test shall be conducted after the pipeline and/or facilities have been installed.

B. Each service line temporarily disconnected from the main must be tested from the point of disconnection to the service line valve in the same manner as a new service line prior to reconnecting. However, if provisions are made to maintain continuous service, such as by installation of a bypass, any part of the original service line used to maintain continuous service need not be tested.

C. The test medium must be one permitted by Note 5 to Table A-1 in Attachment A on Page 14. Factors to be considered when choosing a test media shall include safety, availability, and economy.

D. Pipe held for emergency use shall be tested as specified in Attachment A.

E. Pipelines should be tested as required to support a MAOP equal to the future design pressure. Testing to support only a lower MAOP is acceptable, but an additional test or uprating will be required to justify any subsequent increases in the MAOP.

STA. ____________________

JOB NO. ____________________

B/M ITEM NO. ____________________

DESIGN CRITERIA

LOCATION CLASS ____________________

DESIGN FACTOR ____________________

FDP __________ SMYS__________ %

MAOP __________ SMYS__________ %

STRENGTH TEST PRESSURE

MAX. __________ PSIG __________ % SMYS

MIN. __________ PSIG __________ % SMYS

____________________ PSIG = 90% SMYS

TEST MEDIUM ____________________

PIPE SPEC. ____________________

OD ____________________

WT ____________________

WELD INSPECTION (GAS STD. D-40)*

ffi RADIOGRAPHIC

ffi 20% MIN. (% of each welder's daily work)

ffi 100%

*VISUALLY INSPECT 100% OF ALL WELDS THAT ARE NOT RADIOGRAPHICALLY INSPECTED. (THIS REQUIREMENT APPLIES EVEN IF NO RADIOGRAPHIC INSPECTION IS REQUIRED.)

Figure 1
Design Criteria Stamp

F.Facilities Damaged by Construction Work

(1) All facilities known or suspected to have been struck during excavation or construction activities must be checked to ensure their safety if they are to remain in service.

(2) Transmission and Distribution Lines

The inspection, repair, and testing required for a damaged transmission or distribution line will depend on the extent of the damage and other conditions, which can best be determined by the responsible supervisor in the field. However, adequate steps must be taken, either by testing or leak survey, to ensure that leaks are not present.

a. Repairs to damaged steel transmission or distribution lines shall be made according to Utility Procedure TD-4100P-05.

b. Repairs to damaged plastic mains shall be made according to Numbered Document A-93.1.

c. Special attention shall be given to a damaged casing for a plastic insert. Ensure that the damage did not result in a failure in the plastic at another location remote from the point of contact.

(3) Service Lines (Including Service Risers)

a. If a steel, copper, or other metallic service line, or if the casing for a metallic insert has been broken, bent, pulled, crushed, or otherwise deformed, the service shall be tested from tee to riser according to Attachment A.

b. Steel, copper, or other metallic service lines or casings for metallic inserts that have been hit but not moved or deformed may be leak surveyed with a leak detector as an alternate check. The survey should include the entire length of the service and adjacent areas, as appropriate.

c. See Numbered Document A-93.1 for a description of approved plastic lines and plastic inserts, and for information on testing plastic service risers which may have been exposed to excessive heat.

d. All service risers that have been struck and/or damaged in aboveground incidents shall be leak surveyed with a leak detector. The survey must include the service line adjacent to the customer's building and/or other areas, as appropriate.

G. Instrument Lines

Buried instrument piping that is subjected directly to mainline gas pressures shall be tested according to the applicable test requirements in Table A-1. It is not necessary to test tubing, but all fittings and connections should be checked for leaks after start-up.

H. Branch Connections and Fittings

(1) For installation of a hot tap branch connection with reinforcement pad or sleeve, the branch-to-header weld shall be leak tested for a minimum of 5 minutes before installing the reinforcement pad or sleeve. The minimum test pressure shall be 100 psig. The maximum test pressure shall be 110 psig.

(2) When installing line stopper fittings, the fitting shall be leak tested for a minimum of 5 minutes after it has been completely welded to the pipe and before tapping. The minimum test pressure shall be 100 psig. The maximum test pressure shall be 110 psig.

I. Service-Line Connection (Other Than Plastic)

If feasible, the service-line connection to the main must be included in the leak test with the service line. If this is not feasible, it must be given a leakage test at the operating pressure when placed in service.

J. Spike Testing

(1) For testing an existing pipeline (typically for uprating, or confirming MAOP), a spike test will be conducted when possible. A spike test requires the test pressure to be initially raised to a range of 5-10% higher than the minimum test pressure at maximum elevation, and held at that elevated pressure for between 15 and 30 minutes, and then lowered by at least 5% to the desired test pressure for the remainder of the required test duration.

(2) For any applicable pressure tests where a spike test is not practical, the project manager shall prepare, or will work with Regulatory Compliance & Support to prepare a letter notice setting forth the reasons such tests will not be performed. The letter notice shall be sent to CPUC's Consumer Protection and Safety Division (CPSD) at least one week in advance of the test. The advance notice will describe the specific pipeline facility, or component, which PG&E believes would preclude the spike test from being performed to a minimum level of at least 5% above that required to establish MAOP.

K. Soap/Leak Testing

(1) Welds that have not been strength tested (tie-in welds) must be soap tested at 100 – 110 psig and at operating pressure prior to being backfilled.

(2) Leak/soap test at 100-110 psig branch weld connections, pressure control fittings, and Type B sleeves.

(3) Leak/soap test non-welded joints at no less than the pipe segment's operating pressure.

7. Test Limitations on Valves, Fittings and Flanges

A. When performing a hydrostatic test on a line, the test pressure to which a valve may be subjected must not exceed the manufacturer's shell test pressure. Where the required MAOP of the line cannot be established because of these limitations, an engineering study must be made to verify that it is safe to subject the valve to the higher pressure during the test. When making this study, consideration shall be given to:

(1) The pressure to which the valve was tested by the manufacturer,

(2) The age and condition of the valve, and

(3) The effect of stresses which may be transmitted to the valve by the pipeline.

B. When performing a test with air or inert gas, or an uprating with natural gas, the pressure to which a valve may be subjected shall be limited to 110% of the maximum working pressure of the valve. Where the required MAOP of the line cannot be established because of this limitation, the responsible operating department shall determine whether a higher test pressure may be permitted. This limitation shall not apply to the 100 psig air test on a service line.

C. When a valve is to be subjected to a test pressure which is greater than its maximum working pressure, it shall normally be in the open position. However, with prior approval from the responsible operating department, closed valves may be subjected to a hydrostatic test pressure exceeding their maximum working pressure. Approval will depend on the type and condition of the valve, and will only be given with the limitations that (1) the differential pressure not exceed the working pressure and (2) the test pressure not exceed the manufacturer's shell test pressure.

D. When practical, mainline valve assemblies must be tested separately from pipeline construction to prevent damage to the valves during the initial pipeline pigging. The separate valve assembly test must be followed by a 100 psig leak test of the valve seats before welding the assembly in the pipeline.

E. Test pressure to which fittings and flanges may be subjected to-must not exceed the manufacturers' test pressure.

8. Records

A. Facilities Designed to Operate at 100 psig or Greater

(1) Estimate sketches and design drawings must contain the following information: specifications of pipe, fittings, and valves; design pressure; MAOP; class location; design factor and strength, or leak test information. Where more than one size of pipe is involved, the required information shall be supplied for each size and type.

(2) A "Gas Pipeline Facilities Strength Test Pressure Report" (see Attachment G) is required for each facility being tested to support a MAOP of 100 psig or greater (see Attachment A).

(3) A test chart is required for all strength tests. (see Item 9, "Test Chart").

(4) An electronic pressure recorder or dead weight tester is required when testing any segment of the test section over 90% SMYS. Electronic pressure recorders must record pressure a minimum of every 15 seconds and print out the pressure recording no longer than 15 minute interval. A log of the DWT reading must be made every 15 minutes. The pressure recording chart and the DWT log must be submitted with the "Gas Pipeline Facilities Strength Test Pressure Report." The DWT log must be considered the official record of the test. In the event that the DWT fails during the test, the pressure recording chart may be accepted as the official test record, provided the recording chart has been correlated to the DWT at the beginning of the test.

(5) "Job Estimate," Form 62-6251, shall be marked by the person preparing the estimate to indicate if the pipe must be strength tested.

B. Facilities Designed to Operate at Less Than 100 psig

For facilities designed to operate at less than 100 psig, test information shall be recorded on the "Gas Service Record" form, on the estimate sketch, and on the work order or other authorized form.

C. For systems being uprated, it is required to complete a test chart according to Item 9.

D. All required test records shall be retained by the responsible operating department for the useful life of the facility.

9. Test Chart

All pressure recording equipment, whether primary (official record) or secondary (backup) must be calibrated.

A test chart record shall be made of pressure tests on all upratings and on pipelines and facilities with a FDP of 100 psig or greater. The procedure for handling the chart, and the minimum information required on the chart, are described below:

A. The chart must be designed for the recorder on which it is to be used and shall have appropriate scale and time lines.

B. The recorder must be calibrated within 1% accuracy every 6 months. Dead weight testers must be calibrated within 0.5% accuracy every 12 months. The recorder and DWT's calibration records must be checked before conducting the test. Intervals for recording pressures during testing will be in **15 minute increments** with all pressure recording equipment.

C. The chart must be set on the correct time at the start of the test. The actual time, date, and initials of the person starting the test must be written on the face of the chart at the start of the test.

D. The chart must document a minimum of 8 hours of testing (except where a 4-hour test is permitted in Attachment A). Any discrepancies must be explained.

E. At the end of the test, the actual time, date, and initials of the person removing the chart shall be written on the face of the chart.

F. The section of pipe being tested must be identified on the face of the chart, along with the job number.

G. The following information must be recorded on the back of the chart at the time of the test.

(1) job number.

(2) location of test.

(3) test pressure, date, and duration.

(4) size, wall thickness, pipe specification, and length of section tested.

(5) serial number of the recorder or other means of identification.

(6) date the recorder was last calibrated and serial number of the DWT or other reference standard used.

H. After the test is completed, the supervisor must review the chart, and then sign and date it to verify that it complies with the requirements of this numbered document.

I. The original test chart must be attached to the original of the "Gas Pipeline Facilities Strength Test Pressure Report," Form 62-4921. A copy of the test chart must be attached to each copy of the "Gas Pipeline Facilities Strength Test Pressure Report". This record must be retained for the life of the facility.

Attachments

Revision Notes

Revision 04 has the following changes:

1. Revised Acronyms, added EW, HFW and SAWL.
2. Revised "Definitions", added definitions from 49 CFR 192 with corresponding PG&E Definitions as appropriate.
3. Revised "Design", added note 3 under "General".
4. Added new paragraph 4.B for corrosion control.
5. Updated Figure 1, Design Criteria Stamp.
6. Reworded General Information 6.H. Instrument Lines. Made editorial changes to Paras 6.L.
7. Revised Attachment A, Made editorial changes to Notes 1, 3C, 4 and Para 12.
8. Revised Attachment B, added SAWL, HPW to Notes. Made minor editorial change to Para 3.
9. Revised Table B-1 and B-2 notes.
10. Deleted Table B-3 (API-5L Grade A-25), renumber B-4 thru B-7 accordingly.
11. Revised new Table B-3 thru B-6. Added new Table B-7.
12. Revised Attachment F.
13. Added new and revised STPR Form.
14. Incorporates information from gas bulletins TD-A-34B-001 and TD-A-34B-002.
15. This document is part of Change 66.

Attachment A – Test Requirements

Table A-1 Test Requirements for Pipelines, Mains, Services, Instrument Lines, and Other Gas Facilities

<table>
<tr><th colspan="2" rowspan="2">Proposed MAOP</th><th rowspan="2">Plastic (See Note 1 on Page 14)</th><th colspan="5">Steel</th></tr>
<tr><th>Less Than or Equal to 60 psig (Including Low Pressure)</th><th>Over 60 and Less Than 100 psig</th><th>Under 30% SMYS and at or Above 100 psig</th><th>30% SMYS or More</th><th rowspan="2">Pretested Pipe for Emergency Use (See Note 3 on Page 14)</th></tr>
<tr><td colspan="2">Component to be Tested</td><td colspan="4">Pipelines, Mains, Services, Fabricated Units, and Short Sections of Pipe</td><td>Pipeline, Fabricated Units, Short Sections of Pipe</td></tr>
<tr><td colspan="2">Type of Test</td><td>Leak</td><td>Leak</td><td>Leak</td><td>Strength</td><td>Strength</td><td>Strength</td></tr>
<tr><td colspan="2">Test Medium (See Note 4 on Page 14)</td><td colspan="3">Air or Gas (See Note 5 on Page 14)</td><td colspan="2">Water, Air, Inert Gas, or Gas (See Notes 5, 6, and 7 on Page 14)</td><td>Water</td></tr>
<tr><td colspan="2">Maximum Test Pressure (See Notes 6 and 7 on Page 14)</td><td>150 psig</td><td>110 psig</td><td>300 psig</td><td>(See Notes 8 and 9 on Page 14)</td><td>100% SMYS or Factory Test Pressure of Fitting (See Notes 8 and 10 on Pages 14 and 15)</td><td>100% SMYS</td></tr>
<tr><td colspan="2">Minimum Test Pressure</td><td>100 psig or 1.5 x MAOP Whichever is Greater</td><td>100 psig (See Note 11 on Page 15)</td><td>1.5 x MAOP</td><td>1.5 x Design Pressure (See Note 12 on Page 15)</td><td>1.5 x Design Pressure (See Notes 10 and 12 on Page 15)</td><td>90% SMYS Recommended</td></tr>
<tr><td colspan="2">Duration of Test</td><td colspan="3">5 Minutes (See Note 2 on Page 14 and Note 13, for Plastic, on Page 15)</td><td>1 Hour Minimum (See Note 2 on Page 14 and Note 14 on Page 16)</td><td>8 Hours Minimum (See Note 2 on Page 14 and Note 14 on Page 16)</td><td>4 Hours Minimum</td></tr>
<tr><td rowspan="2">Test Records Required (See Note 15 on Page 16)</td><td>Forms Required</td><td colspan="3">Complete Box on Job Estimate Form or Gas Service Record Form</td><td colspan="3">Completed Strength Test Pressure Report</td></tr>
<tr><td>Test Chart</td><td colspan="3">No (See Note 16 on Page 16)</td><td>No (See Note 16 on Page 16)</td><td colspan="2">Yes (See Note16 and 17 on Page 16)</td></tr>
</table>

Attachment A, continued

Notes

1. The temperature of thermoplastic material shall not be more than 100°F, or the temperature at which the material's long-term hydrostatic strength has been determined under ASTM D 2513-99, whichever is greater. The duration of pressure test for thermoplastic pipe must not exceed 8 hours per Plastic Manual.
2. Pre-Installation Tests
   A. For fabricated units and short sections of pipe for which a post-installation test is impractical, a pre-installation test may be substituted. The pre-installation test shall be conducted whenever possible at the jobsite and shall comply with the pressure requirements for a post-installation test. If the test cannot be conducted at the jobsite, the pipe shall be visually inspected before installation to ensure that it has not been damaged during transit to the jobsite. A fabricated unit is defined as an assembly of one or more fittings with pipe, equipment with pipe, or pieces of pipe joined together. Examples include, but are not limited to, mainline valve assemblies, branch connections, and tie-in pieces.
   B. For fabricated units or short sections that will have a MAOP at or above 30% SMYS, the pre-installation test shall be a minimum of 4 hours.
3. Testing Emergency Stock Pipe
   A. The following blocks in Part 1 of the "Gas Pipeline Facilities Strength Test Pressure Report" should not be completed for emergency pipe since it is not known at the time of the test where the pipe will be installed: "Location Class," "Design Factor," "MAOP of Existing Facilities," "MAOP to Be Established by This Test," "Design Pressure − This Section (Use Future Design Pressure whenever possible,)" and "% of SMYS at Design Pressure."
   B. It is recommended that all emergency pipe be tested to a minimum of 90% of SMYS for a minimum of 4 hours.
   C. The Emergency Pipe Test Information form (see Attachment H) shall be completed after the strength test and attached to the "Gas Pipeline Facilities Strength Test Pressure Report."

   For emergency repairs, some exceptions to the design and test requirements may be permitted, but only with the approval of Pipeline Engineering.
4. All tests to over 50% of 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 6 on Page 14. When a test using air or inert gas is being performed in a class 1 or 2 location, buildings intended for human occupancy within 300 feet of the test section must be evacuated if hoop stress exceeds 50% SMYS.
5. Testing using water, air, or inert gas is not normally permitted where the test section is isolated from an operating line by only a closed valve, squeeze-off equipment, or plugging equipment. This is because a leak may occur, creating an undesirable and potentially hazardous situation. If the test must be performed under these conditions, obtain approval from a Pipeline Engineer (see Attachment D, Note 7, Professional Engineering Review). Additional precautions may be required in order to minimize the possibility of an accident. For test limitations on valves, see Item 7 on Page 9.
6. Maximum test pressure permitted, expressed as a percent of SMYS.

Class Location	1	2	3	4
Air or Inert Gas (See Note 4 on Page 14)	80	75	50	40
Natural Gas	80	30	30	30
Water	100	100	100	100

7. Safety − When testing with air, inert gas, or natural gas, the pressure shall be held at about 100 psig and observed for leakage before raising to the required test pressure.
8. Maximum test capabilities of fittings (i.e., valves and elbows) must be determined before testing (see Item 7 on Page 9).
9. For facilities operating at or under 30% of SMYS and at or above 100 psig, the maximum test pressure shall be determined by the responsible engineer. A reasonable differential between maximum and minimum test pressures should be allowed, considering elevation differentials and the requirements of Note 8 above. A test chart record shall be made of pressure tests on all upratings and on pipelines and facilities with a FDP of 100 psig or greater.

Attachment A, *continued*

10.Testing Pipelines and Station Piping

A.All pipelines 6" and larger, designed to operate at more than 40% of SMYS, **consideration should be given to test to** 90% of SMYS, and as close to 100% of SMYS as practical. (Tests of ERW pipe should be limited to a maximum of 95% of SMYS.) This will permit them to continue to operate at an established MAOP should a class location change occur. Do not use a test to 90% of SMYS as an alternative to designing a pipeline to meet a higher class location which may reasonably be anticipated to occur in the future.

B.For pipelines 6" and larger, which are designed to operate at over 20% of SMYS and up to 40% of SMYS, consideration should be given to test to a minimum of 90% of SMYS. Testing to this pressure will provide additional assurance of the integrity of the line and will minimize the possibility of a failure due to stress resulting from soil settlement or other environmental effects. The decision to conduct a test to the higher pressure should be based on engineering judgment, and take into account:

(1) The importance of the line to meet system demand, and

(2) Any potential environmental effects on the line as might be caused by intense development or heavy construction near the line.

C.It is often not practical to test station piping to 90% of SMYS because of limitations of valves, flanges, and other devices. In these cases, the station will not be able to continue to operate after a class location change that results in a design factor lower than the required minimum 0.5 design factor for stations. Therefore, it is extremely important that the station be designed for the lowest design factor that might occur during the life of the station. If an area is anticipated to change in the near future to Class 4, use a 0.4 design factor so the station can continue to operate after the change.

11.Cut, test, and transferred services in low pressure distribution systems that will remain low pressure shall be leak tested to 10 psig for pipelines other than plastic, or 50 psig or 1.5 times minimum operating pressure, whichever is greater for plastic pipelines. These include:

A.Services which must be extended with new pipe in order to tie into the new main, and

B.Repaired services (i.e., services with segments that have been repaired or replaced with new pipe).

12.The minimum test pressure shall not be less than 1.5 times the future design pressure in Class 2, 3, and 4 locations, and not less than 1.25 times the future design pressure in a Class 1 location.

In special circumstances, exceptions may be granted for tests in Class 2 locations, as follows:

ffl *When testing to 1.5 times the future design pressure creates problems for any of the following reasons:*

ffl *limitations imposed by valves, fittings, flanges (see Note 8)*

ffl *variations in pipe/fitting specifications*

ffl *elevation changes*

ffl *MAOP to be established is below the future design pressure*

A waiver may be granted by the Director of Transmission Engineering and Design for the use of 1.25 test pressure ratio, as an exception.

Example: *Within the pipeline section to be tested, the maximum test pressure limits for pipe and components may vary widely such that the testing to 1.5 test pressure ratio would exceed the maximum pressure limit for some components. In such situation, to meet PG&E's ratio of 1.5, a number of separate tests on separate sections of pipe would be required.*

In consideration of customer impacts or environmental concerns, it would be prudent to combine multiple tests into a single test by using the 1.25 test pressure ratio. Such test pressure ratio is consistent with 49 CFR 192.611.

ffl *For uprates, MAOP validation (based on historical design, construction and/or previous hydrostatic test information), and when testing existing pipelines to 1.5 MAOP test pressure ratio is not practical, a waiver may be granted for the use of a 1.25 MAOP test pressure ratio on an exception basis. The waiver may be granted by the applicable Director Transmission Process & MAOP Validation or Director of Hydrostatic Testing Engineering.*

ffl *The exception documentation must be prepared by the appropriate gas engineer and routed to the appropriate approver. The record of approved deviation shall be filed in the permanent job file and/or PFL build file for MAOP validation, and retained for the life of the pipeline.*

13.Although the test duration for plastic pipe is 5 minutes, it is desirable to maintain the test pressure for a longer period of time, not exceeding 8-hour duration, if the construction schedule permits. If the pipe is not gassed up on the same day as the test, it shall be retested before gassing up.

Attachment A, continued

14. 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 numbered document. For pipelines with a MAOP over 200 psig located on California state bridges, the test pressure shall be maintained for a minimum of 24 hours.
15. All records that document leak and strength tests shall be retained for the life of the facility.
16. Table A-1 on Page 13 indicates test chart requirements for new facilities. Test charts are required for all upratings regardless of the operating pressure of the line.
17. Test charts shall be completed and retained as outlined in Item 9 on Page 10.

Attachment B – Steel Pipe Specifications

Notes

1. The symbols and abbreviations used in the tables in this attachment refer to the following:

   API – American Petroleum Institute

   DSAW – Double Submerged Arc Welded pipe

   (New terminology: SAWL pipe - submerged arc welded longitudinal pipe - a tubular product having one or two longitudinal seam produced by submerged-arc welding process)

   ERW – Electric Resistance Welded pipe

   (New terminology: HFW pipe - high frequency welded pipe - an EW pipe produced with welding current frequency equal to or greater than 70 kHz)

   (New terminology: EW pipe - electric welded pipe - Tubular product having one longitudinal seam produced by low- or high-frequency electric welding).

   SMYS – Specified Minimum Yield Strength

   20%, 30%, etc. means % of SMYS.

2. A-25 and X-42 are the most economical choices for most applications through 10".

   Grade B is normally used when seamless pipe is required.

   X-52, X-60, X-65 and X-70 become desirable as diameters and operating pressures increase.

3. Other combinations of size, grade, and wall thickness are available.

   Pipeline Engineering should be consulted if a pipe that is not shown is to be used or if there is a question as to the most economical grade or wall thickness for a particular application.

4. "Standard Wall" pipe (see Numbered Document A-10) is the minimum allowable wall thickness for bridge crossings. Minimum allowable wall thicknesses for pipe sizes 2" through 8" for use in gathering systems are indicated in Table B-1, Table B-2, and Table B-3 of this attachment. Minimum allowable wall thickness for fabricated assemblies and stations are indicated in Attachment C. Consult the Pipeline Engineering if further information is required.

5. When specifying pipe, the following information shall be given in sequence:

   A. Outside diameter and wall thickness.

   B. API specification and grade.

   C. Longitudinal seam welding process.

   D. Coating: Specify bare or coated. If coated, the type of coating for each installation must be recorded in the permanent records (see Numbered Document E-10).

   E. PG&E code number. (See Numbered Document A-15).

6. Examples

   A. Typical coated pipe specification for either orders or records:

      16" OD x 0.250 WT

      API 5L Grade X-42, ERW, Wrapped

      Code 011286

   B. Typical bare pipe specification for either orders or records:

      4.50" OD x 0.237 WT

      API 5L Grade B, Seamless

      Code 011693

Attachment B, continued

Table B-1 Steel Pipe Specification - API 5L Grade B Seamless, 35,000 psi SMYS

Nominal Pipe Size (Inches)	Outside Diameter [3, 4] (Inches)	Wall Thickness [3, 4] (Inches)	Pressure at % of SMYS (psig)							
			Class Location:		1	2	3	4		
			100%	**90%**	**72%**	**60%**	**50%**	**40%**	**30%**	**20%**
3/4 [1]	1.05	0.113	7,534	6,780	5,424	4,520	3,767	3,014	2,260	1,507
1-1/4 [1]	1.66	0.140	5,904	5,314	4,251	3,543	2,952	2,362	1,772	1,181
2 [1, 2]	2.375	0.154	4,539	4,086	3,269	2,724	2,270	1,816	1,362	908
3 [1]	3.5	0.216	4,320	3,888	3,111	2,592	2,160	1,728	1,296	864
4 [1]	4.5	0.237	3,687	3,318	2,655	2,212	1,844	1,475	1,106	738
6 [1]	6.625	0.280	2,959	2,663	2,131	1,776	1,480	1,184	888	592
8 [1]	8.625	0.322	2,614	2,352	1,882	1,568	1,307	1,046	784	523
10	10.75	0.365	2,377	2,140	1,712	1,427	1,189	951	714	476
12	12.75	0.375	2,059	1,853	1,483	1,236	1,030	824	618	412
16	16.0	0.375	1,641	1,477	1,182	985	821	657	493	329
20	20.0	0.375	1,313	1,182	945	788	657	525	394	263
24	24.0	0.375	1,094	985	788	657	547	438	329	219

[1] Pipe normally in stock. For codes, see Numbered Document A-15.
[2] Pipe is the minimum allowable grade and wall thickness for use in gas field gathering systems with a MAOP of 800 psig or less.
[3] In the design formula for steel pipe, these correspond to outside diameter (D) and nominal wall thickness (t).
[4] Other sizes and wall thickness are available from pipe manufacturers. Consult Pipeline Engineering for assistance.

Table B-2 Steel Pipe Specification - API 5L Grade B ERW, 35,000 psi SMYS

Nominal Pipe Size (Inches)	Outside Diameter [3, 4] (Inches)	Wall Thickness [3, 4] (Inches)	Pressure at % of SMYS (psig)							
			Class Location:		1	2	3	4		
			100%	**90%**	**72%**	**60%**	**50%**	**40%**	**30%**	**20%**
3 [1, 2]	3.5	0.156	3,120	2,808	2,247	1,872	1,560	1,248	936	624
4 [1, 2]	4.5	0.156	2,427	2,184	1,748	1,456	1,214	971	728	486
6	6.625	0.219	2,314	2,083	1,667	1,389	1,157	926	695	463
8	8.625	0.219	1,778	1,600	1,280	1,067	889	711	534	356
10	10.75	0.219	1,427	1,284	1,027	856	714	571	428	286
12	12.75	0.219	1,203	1,083	866	722	602	481	361	241
14	14.0	0.250	1,250	1,125	900	750	625	500	375	250
16	16.0	0.250	1,094	985	788	657	547	438	329	219

[1] Pipe normally in stock. For codes, see Numbered Document A-15.
[2] Pipe is the minimum allowable grade and wall thickness for use in gas field gathering systems with a MAOP of 800 psig or less.
[3] In the design formula for steel pipe, these correspond to outside diameter (D) and nominal wall thickness (t).
[4] Other sizes and wall thickness are available from pipe manufacturers. Consult Pipeline Engineering for assistance.

Attachment B, continued

Table B-3 Steel Pipe Specification – API 5L Grade X-42, 6"–18" ERW, 16"–42" DSAW, 42,000 SMYS

Nominal Pipe Size (Inches)	Outside Diameter [3, 4] (Inches)	Wall Thickness [3, 4] (Inches)	Pressure at % of SMYS (psig)							
			Class Location:		1	2	3	4		
			100%	**90%**	**72%**	**60%**	**50%**	**40%**	**30%**	**20%**
6	6.625	0.156 [1, 2]	1,978	1,781	1,425	1,187	989	792	594	396
		0.172	2,181	1,963	1,571	1,309	1,091	873	655	437
		0.188 [1]	2,384	2,146	1,717	1,431	1,192	954	716	477
8	8.625	0.172 [2]	1,676	1,508	1,207	1,006	838	671	503	336
		0.188 [1]	1,831	1,648	1,319	1,099	916	733	550	367
		0.219 [1]	2,133	1,920	1,536	1,280	1,067	854	640	427
10	10.75	0.219	1,712	1,541	1,233	1,027	856	685	514	343
		0.250 [1]	1,954	1,759	1,407	1,173	977	782	587	391
		0.281	2,196	1,977	1,581	1,318	1,098	878	659	440
		0.365	2,853	2,567	2,054	1,712	1,427	1,141	856	571
12	12.75	0.219	1,443	1,299	1,039	866	722	578	433	289
		0.250	1,648	1,483	1,186	989	824	659	495	330
		0.281 [1]	1,852	1,667	1,333	1,111	926	741	556	371
		0.375 [1]	2,471	2,224	1,779	1,483	1,236	989	742	495
16	16.0	0.250	1,313	1,182	945	788	657	525	394	263
		0.281	1,476	1,328	1,063	886	738	591	443	296
		0.375 [1]	1,969	1,772	1,418	1,182	985	788	591	394
18	18.0	0.250	1,167	1,050	840	700	584	467	350	234
		0.312	1,456	1,311	1,049	874	728	583	437	292
20	20.0	0.250	1,050	945	756	630	525	420	315	210
		0.281	1,181	1,063	850	709	591	473	355	237
		0.312	1,310	1,180	944	787	656	525	394	263
		0.344	1,445	1,301	1,041	867	723	578	434	289
		0.375	1,575	1,418	1,134	945	788	630	473	315

[1] Pipe normally in stock. For codes, see Numbered Document A-15.
[2] Pipe is the minimum allowable grade and wall thickness for use in gas field gathering systems with MAOP of 800 psig or less. Refer to Numbered Document B-20 for thin wall fittings suitable for welding to this pipe.
[3] In the design formula for steel pipe, these correspond to outside diameter (D) and nominal wall thickness (t).
[4] Other sizes and wall thickness are available from pipe manufacturers. Consult Pipeline Engineering for assistance.

Attachment B, continued

Table B-3 Steel Pipe Specification – API 5L Grade X-42, 6"–18" ERW, 16"–42" DSAW, 42,000 SMYS, continued

Nominal Pipe Size (Inches)	Outside Diameter [1, 2] (Inches)	Wall Thickness [1, 2] (Inches)	Pressure at % of SMYS (psig)							
			Class Location:		1	2	3	4		
			100%	**90%**	**72%**	**60%**	**50%**	**40%**	**30%**	**20%**
22	22.0	0.250	955	860	688	573	478	382	287	191
		0.312	1,192	1,073	858	715	596	477	358	239
24	24.0	0.250	875	788	630	525	438	350	263	175
		0.281	984	886	709	591	492	394	296	197
		0.312	1,092	983	787	656	546	437	328	219
		0.344	1,204	1,084	867	723	602	482	362	241
		0.375	1,313	1,182	945	788	657	525	394	263
26	26.0	0.281	908	818	654	545	454	364	273	182
		0.312	1,008	908	726	605	504	404	303	202
		0.344	1,112	1,001	801	667	556	445	334	223
30	30.0	0.406	1,137	1,024	819	683	569	455	342	228
		0.438	1,227	1,104	884	736	614	491	368	246
		0.469	1,314	1,182	946	788	657	526	394	263
32	32.0	0.469	1,232	1,109	887	739	616	493	370	247
		0.500	1,313	1,182	945	788	657	525	394	263
		0.562	1,476	1,328	1,063	886	738	591	443	296
34	34.0	0.469	1,159	1,043	835	696	580	464	348	232
		0.500	1,236	1,112	890	742	618	495	371	248
		0.562	1,389	1,250	1,000	834	695	556	417	278
36	36.0	0.500	1,167	1,050	840	700	584	467	350	234
		0.562	1,312	1,181	945	787	656	525	394	263
		0.625	1,459	1,313	1,050	875	730	584	438	292
40	40.0	0.562	1,181	1,063	850	709	600	473	355	237
		0.625	1,313	1,182	945	788	657	525	394	263
		0.688	1,445	1,301	1,041	867	723	578	434	289
42	42.0	0.562	1,124	1,012	810	675	562	450	338	225
		0.625	1,250	1,125	900	750	625	500	375	250
		0.688	1,376	1,239	991	826	688	551	413	276

[1] In the design formula for steel pipe, these correspond to outside diameter (D) and nominal wall thickness (t).
[2] Other sizes and wall thickness are available from pipe manufacturers. Consult Pipeline Engineering for assistance.

***Attachment B,** continued*

Table B-4 Steel Pipe Specification – API 5L Grade X-52, 10”–18” ERW, 16”–42” DSAW, 52,000 SMYS

Nominal Pipe Size (Inches)	Outside Diameter [2, 3] (Inches)	Wall Thickness [2, 3] (Inches)	Pressure at % of SMYS (psig)							
			Class Location:		1	2	3	4		
			100%	**90%**	**72%**	**60%**	**50%**	**40%**	**30%**	**20%**
10	10.750	0.219	2,119	1,907	1,526	1,272	1,060	848	636	424
12	12.750	0.219	1,787	1,608	1,287	1,072	894	715	536	358
		0.250	2,040	1,836	1,469	1224	1,020	816	612	408
16	16.0	0.250	1,625	1,463	1,170	975	813	650	488	325
		0.281	1,827	1,644	1,316	1,096	914	731	548	366
		0.312	2,028	1,826	1,461	1,217	1,014	812	609	406
18	18.0	0.250	1,445	1,300	1,040	867	723	578	434	289
20	20.0	0.250	1,300	1,170	936	780	650	520	390	260
		0.281	1,462	1,316	1,053	877	731	585	439	293
		0.312	1,623	1,461	1,169	974	812	649	487	325
		0.344	1,789	1,610	1,288	1,074	895	716	537	358
		0.375 [1]	1,950	1,755	1,404	1,170	975	780	585	390
		0.406	2,112	1,901	1,521	1267	1,056	845	634	423
22	22.0	0.250	1,182	1,064	851	710	591	473	355	237
24	24.0	0.250	1,084	975	780	650	542	434	325	217
		0.281	1,218	1,096	877	731	609	488	366	244
		0.312	1,352	1,217	974	812	676	541	406	271
		0.344	1,491	1,342	1,074	895	746	597	448	299
		0.375	1,625	1,463	1,170	975	813	650	488	325
		0.438	1,898	1,709	1,367	1,139	949	760	570	380
26	26.0	0.281	1,124	1,012	810	675	562	450	338	225
		0.312	1,248	1,124	899	749	624	500	375	250
		0.344	1,376	1,239	991	826	688	551	413	276
		0.375	1,500	1,350	1,080	900	750	600	450	300

[1] Pipe normally in stock. For codes, see Numbered Document A-15.
[2] In the design formula for steel pipe, these correspond to outside diameter (D) and nominal wall thickness (t).
[3] Other sizes and wall thickness are available from pipe manufacturers. Consult Pipeline Engineering for assistance.

Attachment B, continued

Table B-4 Steel Pipe Specification– API 5L Grade X-52, 10”–18” ERW, 16”–42” DSAW, 52,000 SMYS, continued

Nominal Pipe Size (Inches)	Outside Diameter [1, 2] (Inches)	Wall Thickness [1, 2] (Inches)	Pressure at % of SMYS (psig)							
			Class Location:		1	2	3	4		
			100%	**90%**	**72%**	**60%**	**50%**	**40%**	**30%**	**20%**
30	30.0	0.375	1,300	1,170	934	780	650	520	390	260
		0.406	1,408	1,267	1,014	845	704	563	423	282
		0.438	1,519	1,367	1,091	912	760	608	456	304
32	32.0	0.406	1,320	1,188	950	792	660	528	396	264
		0.438	1,424	1,282	1,028	855	712	570	428	285
		0.469	1,525	1,372	1,097	915	763	610	458	305
		0.500	1,625	1,463	1,170	975	813	650	488	325
34	34.0	0.438	1,340	1,206	965	804	670	536	402	268
		0.469	1,435	1,292	1,033	861	718	574	431	287
		0.500	1,530	1,377	1,102	918	765	612	459	306
36	36.0	0.438	1,266	1,139	912	760	633	507	380	254
		0.469	1,355	1,220	976	813	678	542	407	271
		0.500	1,445	1,300	1,040	867	723	578	434	289
40	40.0	0.500	1,300	1,170	936	780	650	520	390	260
		0.562	1,462	1,316	1,053	877	731	585	439	293
		0.625	1,625	1,463	1,170	975	813	650	488	325
42	42.0	0.500	1,239	1,115	892	743	620	496	372	248
		0.562	1,392	1,253	1,002	835	696	557	418	279
		0.625	1,548	1,393	1,115	929	774	620	465	310

[1] In the design formula for steel pipe, these correspond to outside diameter (D) and nominal wall thickness (t).
[2] Other sizes and wall thickness are available from pipe manufacturers. Consult Pipeline Engineering for assistance.

Attachment B, continued

Table B-5 Steel Pipe Specification – API 5L Grade X-60, 20”–42” DSAW, 60,000 SMYS

Nominal Pipe Size (Inches)	Outside Diameter [2, 3] (Inches)	Wall Thickness [2, 3] (Inches)	Pressure at % of SMYS (psig)							
			Class Location:		1	2	3	4		
			100%	**90%**	**72%**	**60%**	**50%**	**40%**	**30%**	**20%**
20	20.0	0.250	1,500	1,350	1,080	900	750	600	450	300
		0.281	1,686	1,518	1,214	1,012	843	675	506	338
		0.312	1,872	1,685	1,348	1,124	936	749	562	375
		0.375	2,250	2,025	1,620	1,350	1,125	900	675	450
22	22.0	0.250	1,364	1,228	982	819	682	546	410	273
24	24.0	0.250	1,250	1,125	900	750	625	500	375	250
		0.281	1,405	1,265	1,012	843	703	562	422	281
		0.312 [1]	1,560	1,404	1,124	936	780	624	468	312
		0.375	1,875	1,688	1,350	1,125	938	750	563	375
		0.406	2,030	1,827	1,462	1,218	1,015	812	609	406
26	26.0	0.281	1,297	1,168	934	779	649	519	390	260
		0.312	1,440	1,296	1,037	864	720	576	432	288
		0.344	1,588	1,429	1,144	953	794	636	477	318
		0.375	1,731	1,558	1,247	1,039	866	693	520	347
		0.406	1,874	1,687	1,350	1,125	937	750	563	375
30	30.0	0.375	1,500	1,350	1,080	900	750	600	450	300
		0.406	1,624	1,462	1,170	975	812	650	488	325
		0.438	1,752	1,577	1,262	1,052	876	701	526	351
32	32.0	0.375	1,407	1,266	1,013	844	704	563	422	282
		0.406	1,523	1,371	1,097	914	762	609	457	305
		0.438	1,643	1,479	1,183	986	822	657	493	329
34	34.0	0.406	1,433	1,290	1,032	860	716	574	430	287
		0.438	1,546	1,392	1,114	928	773	619	464	310
		0.469	1,656	1,490	1,192	994	823	663	497	332
		0.500	1,765	1,589	1,271	1,059	882	706	530	353
36	36.0	0.406	1,354	1,218	975	812	677	542	406	271
		0.438	1,460	1,314	1,052	876	730	584	438	292
		0.469	1,564	1,407	1,126	938	782	626	469	313
		0.500	1,667	1,500	1,200	1,000	834	667	500	334
40	40.0	0.438	1,314	1,183	947	789	657	526	395	263
		0.469	1,407	1,267	1,014	845	704	563	423	282
		0.500	1,500	1,350	1,080	900	750	600	450	300
42	42.0	0.469	1,340	1,206	965	804	670	536	402	268
		0.500	1,429	1,286	1,029	858	715	572	429	286
		0.562	1,606	1,446	1,157	964	803	643	482	322

[1] Pipe normally in stock. For codes, see Numbered Document A-15.
[2] In the design formula for steel pipe, these correspond to outside diameter (D) and nominal wall thickness (t).
[3] Other sizes and wall thickness are available from pipe manufacturers. Consult Pipeline Engineering for assistance.

Attachment B, continued

Table B-6 Steel Pipe Specification – API 5L Grade X-65, 34”–42” DSAW, 65,000 SMYS

Nominal Pipe Size (Inches)	Outside Diameter [1, 2] (Inches)	Wall Thickness [1, 2] (Inches)	Pressure at % of SMYS (psig)							
			Class Location:		1	2	3	4		
			100%	**90%**	**72%**	**60%**	**50%**	**40%**	**30%**	**20%**
34	34.0	0.375	1,434	1,291	1,033	861	717	574	431	287
		0.406	1,553	1,398	1,118	932	777	621	466	311
		0.438	1,675	1,508	1,206	1,005	838	670	503	335
36	36.0	0.406	1,467	1,320	1,056	880	734	587	440	294
		0.438	1,582	1,424	1,139	949	791	633	475	317
		0.469	1,694	1,525	1,220	1,017	847	678	509	339
		0.500	1,806	1,625	1,300	1,084	903	723	542	362
40	40.0	0.438	1,424	1,282	1,025	855	712	570	428	285
		0.469	1,525	1,372	1,098	915	763	610	458	305
		0.500	1,625	1,463	1,170	975	813	650	488	325
42	42.0	0.469	1,452	1,307	1,046	871	726	581	436	291
		0.500	1,548	1,393	1,115	929	774	620	465	310
		0.562	1,740	1,566	1,253	1,044	870	696	522	348

[1] In the design formula for steel pipe, these correspond to outside diameter (D) and nominal wall thickness (t).
[2] Other sizes and wall thickness are available from pipe manufacturers. Consult the Pipeline Engineering for assistance.

Table B-7 Steel Pipe Specification – API 5L Grade X-70, 42” DSAW (SAWL), 70,000 SMYS

Nominal Pipe Size (Inches)	Outside Diameter [1, 2] (Inches)	Wall Thickness [1, 2] (Inches)	Pressure at % of SMYS (psig)							
			Class Location:		1	2	3	4		
			100%	**90%**	**72%**	**60%**	**50%**	**40%**	**30%**	**20%**
42	42.0	0.407	1,357	1,221	977	814	678	543	407	271
		0.434	1,447	1,302	1,042	868	723	579	434	289
		0.472	1,573	1,416	1,133	944	787	629	472	315
		0.521	1,737	1,463	1,250	1,042	868	695	521	347

[1] In the design formula for steel pipe, these correspond to outside diameter (D) and nominal wall thickness (t).
[2] Other sizes and wall thickness are available from pipe manufacturers. Consult Pipeline Engineering for assistance.

Attachment C – Minimum Wall Thickness for Fabricated Assemblies and Stations

Table C-1 Plain End Pipe Minimum Wall Thickness

Nominal Pipe Size (Inches)	Outside Diameter (Inches)	Minimum Wall Thickness
3/4	1.050	0.113 (Grade B)
1	1.315	0.133 (Grade B)
1-1/4	1.660	0.140 (Grade B)
2	2.375	0.154 (Grade B)
3	3.5	0.216 (Grade B)
4	4.5	0.237 (Grade B)
6	6.625	0.280 (Grade B)
8	8.625	0.322 (Grade B)
10	10.750	0.365 (Grade B)
12	12.750	0.375 (Grade B)
14	14.0	0.375 (Grade B)
16	16.0	0.375 (Grade B)
18	18.0	0.375 (Grade B)
20	20.0	0.375 (Grade B)
22	22.0	0.375 (Grade B)
24	24.0	0.375 (Grade B)
26	26.0	0.375 (Grade B)
30	30.0	0.375 (Grade B)
32	32.0	0.375 (Grade B)
34	34.0	0.375 (Grade B)
36	36.0	0.500 (Grade B)
40	40.0	0.500 (Grade B)
42	42.0	0.500 (Grade B)

Notes

1. For fabricated assemblies/compressor stations (above ground piping), the minimum Grade B material with standard or extra strong wall thickness is based on compatibility with standard and extra heavy wall fittings. Extra strong pipe should be used for all screwed connections through a 2” nominal diameter.
2. Extra strong pipe through a 2” nominal diameter is recommended for compressor stations because of the potential fatigue failure problems due to vibration.

Attachment D – Requirements for Pipeline Plan and Profile/Section Construction Drawings

Purpose and Scope

1. This attachment establishes formatting and review requirements for pipeline drawings. Similar requirements for station drawings are being drafted for inclusion into this numbered document at a later date.
2. Any gas pipeline work that is reportable to the CPUC (Section 125 of G.O. 112E) must have construction drawings that show the plan and profile.
3. In addition, because CPUC G.O. 112E requirements are a minimum criteria and plan and profile/sections drawings demonstrate good pipeline engineering practice, plan and profile/sections drawings shall be used for pipeline work on the following critical lines (even if the work is not reportable under Section 125):

   ffl All numbered transmission pipelines.

   ffl Distribution Feeder Mains (DFMs) that operate at or greater than 20% of SMYS.

   ffl Any critical lines that operate over 60 psig and have elevation variations.

Drawing Format

4. The requirement for pipeline construction drawings can be met by using the existing 3- or 4-size plan and profile construction drawing format. For small projects or simple offsets to clean underground structures, the requirement can be met by using a sections and details drawing format.

Technical Review

5. Any gas pipeline work that is reportable to the CPUC must have a technical review by a qualified engineer as designated by the manager responsible for the facilities.
6. In addition to the CPUC-reportable projects, it is recommended that drawings for pipeline sections that are more than 100' in length or 12" in diameter or larger, and are to be installed on bridges, also be submitted for technical review before being issued for bids or construction.

Professional Engineering Review

7. There is currently no legal requirement for pipeline construction drawings (other than civil and structural drawings) to be stamped by a licensed professional engineer. However, it is current practice to stamp new construction drawings for gas facilities. To emphasize professional engineering reviews and focus accountability, all pipeline plan and profile/section drawings for work on pipelines with a design pressure or future design pressure greater than 60 psig must be reviewed and stamped by a professional engineer. The engineer (civil or mechanical) must be currently registered in the state of California and competent in pipeline engineering as designated by the manager responsible for the facilities.

Attachment E – Required Information for Pipeline Construction Drawings

Purpose and Scope

1. This attachment provides guidelines for preparing and reviewing pipeline construction drawings.

Plan and Profile/Sections

2. In plan view, show the dimensions from the pipeline to fixed, aboveground structures and/or the property line. Show ETSs and all applicable details in the Reference Details section. Show the right-of-way and all substructures. Clearly identify new, existing, or to-be-abandoned gas lines.
3. In profile view, or a section detail, identify significant offsets and the approximate dimensions to substructures which require the offsets. Show the stationing for survey details.
4. Specify the minimum depth of cover.
5. In the Pipeline Details Stationing section, show the stations for all pipeline details, including tie-ins, substructures, valves, elbows, transition points (changes in pipe wall thickness, SMYS, coating, etc.), and ETSs. Indicate all applicable details (tie-ins, ETSs, etc.) shown in the Reference Details section.

Bill(s) of Material

6. A bill(s) of material is required for all pipeline drawings. The Bill of Materials section must include a complete description of all items. Include all PG&E code numbers and reference drawings or numbered documents.
   A. Pipe – Indicate the size, wall thickness, longitudinal seam type, grade, and specification to which the pipe is to be manufactured. Also, identify the type of coating (and joint tape).
   B. Fittings – Indicate the size, wall thickness, special end preparation, material, and grade of pipe to be used. Also, include the specification to which the fitting is to be manufactured.
   C. Valves – Indicate the type of valve (ball, plug, gate, etc.), size, pressure rating, type of end connections, type and configuration of operator (gearing or lever or automatically operated) with dimensions, wall thickness of weld ends (if applicable), and the serial number.
   D. Taps – Indicate the type of reinforcement including grade, wall thickness, size, and the specification of plate material to be used. Refer to the appropriate numbered document for construction information on either the cold branch or hot tap.
   E. Sleeves – Indicate the size, wall thickness, grade, and the specification of the plate material to be used. Also, specify backup strips and the appropriate numbered document containing information on installing and fabricating the sleeve.
   F. Casings – Indicate the size, wall thickness, and grade. Also, specify the numbered document containing information on casings and the approved vent material. Specify the appropriate insulators and end seals.
   G. Pipeline Markers – Specify the type and the numbered document containing information on pipeline markers.
   H. Cathodic Protection – Specify the type and location and the numbered document containing information on cathodic protection. If an insulating fitting is to be installed, specify the manufacturer, size, and type of end connections (e.g., wall thickness, grade, and specification of the pipe to which the fitting is to be welded). If pipe flanges, insulating gaskets, and insulating kits for bolts are to be used, be sure to specify the pressure rating, size, and bore of flanges, the size and number of bolts required, and the size and number of insulating kits required.

Reference Details Section

7. Tie-in details
   A. Include the diameter, wall thickness, grade, seam, and specification of new pipe and the existing pipe to which the new pipe is to be tied. Do not make a tie-in at a fitting or a valve. Also, because stresses due to pipe expansion and contraction tend to be concentrated at elbows, if the new pipe is to be tied to existing pipe having a thinner wall thickness, and the tie-in point is near an existing thin wall elbow or an elbow fabricated from sections of mitered pipe, the design should be changed to replace the existing elbow with one matching the strength of the new pipe.

Attachment E, continued

B. At the tie-in location, if there is a wall thickness difference greater than 3/32", or a pipe yield strength difference between the new and existing pipe, show the applicable weld detail from Numbered Document D-22 on the drawing. In every case, an attempt shall be made to attain an acceptable butt-welded joint. However, if misalignment of carrier pipes or other problems preclude any reasonable possibility of obtaining an acceptable butt-welded joint, use a sleeve. A single-split sleeve is preferred over the double-split sleeve for this purpose.

8. Welding details – Show wall thickness changes greater than 3/32" between adjoining pipe components. Include detail at each change in the line pipe. Line pipe-to-fitting detail can be typical.
9. Trench details – Include a typical trench detail indicating minimum cover, back fill material, and minimum trench width.
10. Crossing details – Include railroad and highway crossings, and all casings and vents. Also, show locations of vent risers.
11. Cathodic protection details – Include a detail for each type of cathodic protection station and reference Numbered Document O-10. For Type E stations, show the dimension between the connection points.

Miscellaneous Requirements

12. Use design criteria stamps for each size, specification, grade, seam type, wall thickness, and location class of pipe shown on specific plan and profile/sections sheets. A separate design criteria stamp is required for each MAOP and for each test pressure.
13. Use a welding requirements stamp.
14. Testing requirements – Include the time, duration of the test, and the maximum and minimum pressures recorded during tests. Fill out a "Strength Test Pressure Report" for each hydro test performed.
15. Signatures of approving parties – Drawings must be signed by the manager responsible for the facility or his or her designated representative.
16. Include the following notes on each sheet:

    A. "All field bends are smooth field bends, except where elbows are noted. Field bends shall be made according to Numbered Document A-36, Item 4D."

    B. "This pipeline must be installed with at least 12" of clearance from any other underground structure not associated with the pipeline."
17. List any reference drawings pertinent to the installation of the piping shown on the plan and profile sections of the drawing.
18. Indicate mile posts at the beginning and end of the project. Also, include the mile post (or stationing) of any taps or valves being installed.
19. Special notes – Indicate additional information if CPUC notification is required. Also, indicate if it is required to notify local agencies and PG&E employees before starting work. Indicate any special construction conditions imposed by the CPUC, local agencies, or PG&E.
20. When hot tapping is required, indicate the maximum pressure allowed in the pipeline during welding and tapping operations.
21. All pipeline plan and profile/sections construction drawings for pipeline work with a design pressure or future design pressure greater than 60 psig shall be reviewed, signed, and stamped by a professional engineer. The engineer (mechanical or civil) must be currently registered in the state of California and competent in pipeline engineering as designated by the manager responsible for the facilities.

Attachment F – Instructions for the Gas Pipeline Facilities Strength Test Pressure Report

Purpose and Scope

Use these instructions to complete Form 62-4921 "Gas Pipeline Facilities Strength Test Pressure Report" (STPR).

General

1. Records of test data are vital for the Company in meeting its regulatory obligations. The test record must be accurate, traceable, verifiable, complete, and maintained for transmission pipelines for the useful life of those pipelines. STPRs must be signed in non-erasable ink by person(s) responsible for the test. Maintain the original chart, log, drawings, and STPR with the job packet to be delivered to the Gas Job Closeout Desk.
2. All data on the report must be legible. Any illegible information on the form (personnel names, values, dates, etc.) can invalidate the test.

Explanation of Form Entries

1. Part I – Test Design Data

   This part of the form must be completed by the engineer/estimator responsible for the design of the strength test and approved by the Project Engineer.

   A. **Sheet ___ of ___**

      Enter the page number of the form and the total number of pages in the form (e.g., 1 of 2). An STPR has at least two pages, Part 1 and Part 2. Each part might consist of multiple pages.

   B. **Test Number ___ of ___**

      Specify the unique identifier associated with the test. One job packet may include more than one test. Enter the test number in the following format: 1 of 5.

   C. **STPR Revision Number**

      Enter 0 for the first version of the STPR. If the form needs to be revised due to a change in test criteria, enter the appropriate revision number, such as 1, 2, etc.

   ffl **Test Description:**

   (1) **Line Number or Station Name**

   Enter the line number or station name for the pipeline being tested, as indicated in the Geographic Information System (GIS) or on related construction drawings.

   (2) **Division/District**

   Specify the district or division where the strength test will be performed.

   (3) **Job Number**

   Specify the job number associated with the section of pipe being tested.

   (4) **Purpose of Test**

   Describe the reason for conducting the strength test. The test may be required to qualify newly installed pipe, to respond to regulatory requirements, for uprating, for integrity management, etc.

   (5) **MAOP to be Established by this Test**

   Specify the maximum allowable operating pressure (MAOP), according to the requirements of Utility Standard TD-4125S. For pipelines that operate at or over 20% of the specified minimum yield strength (SMYS), this value is the MAOP recorded in PG&E Drawing No. 086868.

   (6) **Description of Pipe being Tested**

   Provide a description of the pipe to be tested, including pipe size, pipe length, and pipe location with field or pipe stationing and mile points. Include information that allows field personnel to locate the pipe to be tested. This information indicates the boundaries of the test. Reference the construction drawing number for the site.

   NOTE: If the job packet contains more than one test, ensure that each description identifies the boundaries of that section being tested.

Attachment F, continued

(7) **New Facility/Existing Facility**

Indicate whether the pipeline being tested is new or existing, by marking the appropriate check box.

(8) **Will spike test be performed? (Yes/No)**

If the test is being performed on an existing pipeline, indicate whether a spike test will be performed by marking the appropriate check box.

A spike test is used at the beginning of a pressure test on existing pipelines (uprates, confirming MAOPs, etc.) to verify the structural integrity of pipelines with potential time-dependent anomalies. A spike test is not required for new or replacement lines.

(9) **If no spike test for existing facility, explain:**

If no spike test will be performed on the existing pipeline, enter an explanation. Leave this field blank if the strength test is for a new facility.

IMPORTANT: For pressure tests where a spike test is not practical, the project engineer must prepare or work with Regulatory Compliance to prepare a letter of notice explaining the reasons why such a test will not be performed. The advance notice must describe the specific pipeline facility, component, or issue PG&E believes precludes the spike test from being performed. In addition, notification must be sent to the CPUC's Consumer Protection and Safety Division (CPSD).

ffl **STATIC HEAD CALCULATION:**

When a pipeline is installed through an area where there are differences in elevation, account for the static head due to the weight of the test medium used for the strength test.

(1) **Maximum Elevation**

Enter the maximum elevation of the section of pipe being tested. Obtain this information from the land base survey or third party sources. You must enter a value for this field. Round up to the next foot.

(2) **Minimum Elevation**

Enter the minimum elevation of the section of pipe being tested. Obtain this information from the land base survey or third party sources. You must enter a value for this field. Round down to the next foot.

(3) **Elevation Difference**

Subtract the minimum elevation from the maximum elevation to determine the difference in elevations. If there is no difference between the maximum and minimum elevations, enter a "0" in this field. Do not enter "N/A."

(4) **For Water**

If the test medium is water, obtain the hydrostatic test pressure difference in the pipeline due to the difference in elevation; multiply the difference in elevation (in feet) between the highest point and the lowest point in the test section by 0.433 psig/foot. This provides the pressure differential, in psig, due to the static head of water between the maximum and minimum elevations in the test section. Always round the static head value up to the next psig.

This is the calculation:

$$0.433\,\frac{psig}{ft}\ \text{ffl}\ (elevation\ difference)\,ft\ \text{ffi}\ (pressure\ differential)\,psig$$

(5) **For Other Test Medium**

If using a test medium other than water, contact the responsible engineer to calculate the static head.

(6) **PIPE TO BE TESTED**

For each section of pipe with different specifications, complete a row in the **Pipe to be Tested** table.

For steel fittings (elbows, tees and caps) that are the same grade and wall thickness as the pipe, check the box below the list, titled: **All fittings included in the test (except those listed above) are the same wall thickness and grade as the pipe**. If the steel fitting's grade or wall thickness differs, then enter the information on a separate row. Other items such as valves, flanges, bolts, gaskets, nipples, etc., do not need to be detailed in Part 1; however, to the extent possible, they should be included in the hydrostatic test sketch.

Attachment F, continued

(7) **OD**

Enter the outside diameter of the section of pipe, in inches. Do not use nominal outside diameters. For example, use 10.75 inches instead of 10 inches. Include a leading zero for outside diameters less than one inch. For example, 0.50 inch.

(8) **WT**

Enter the wall thickness of that section of pipe, in inches. Include a leading zero for wall thicknesses less than one inch. For example, 0.375 inch.

(9) **API or ASTM Specification**

Enter the American Petroleum Institute or American Society for Testing and Materials specification of the pipe.

(10) **SMYS**

Enter the specified minimum yield strength of the pipe in psi.

(11) **Long Seam (ERW, DSAW, SMLS, etc.)**

Enter the seam type of each section of pipe. For existing pipe, use the long seam indicated in the Material of Record (MOR) and verified, if possible, during the test. For new pipe, use the appropriate designation indicated in the Materials Purchase Order (MPO), as follows:

ffl Electric Resistance Weld (ERW)
ffl Double Submerged Arc Weld (DSAW)
ffl Seamless (SMLS)
ffl Single Submerged Arc Weld (SSAW)
ffl Submerged Arc Weld Longitudinal (SAWL)
ffl AO Smith
ffl Lap Weld
ffl Electric Fusion Weld
ffl Spiral Weld
ffl Furnace Butt Weld
ffl N/A - Valve/Filter/Other
ffl Polyethylene Pipe
ffl Sleeve
ffl Unknown > 4 inch
ffl Unknown > 4 - Modern
ffl Unknown 4 inch or less

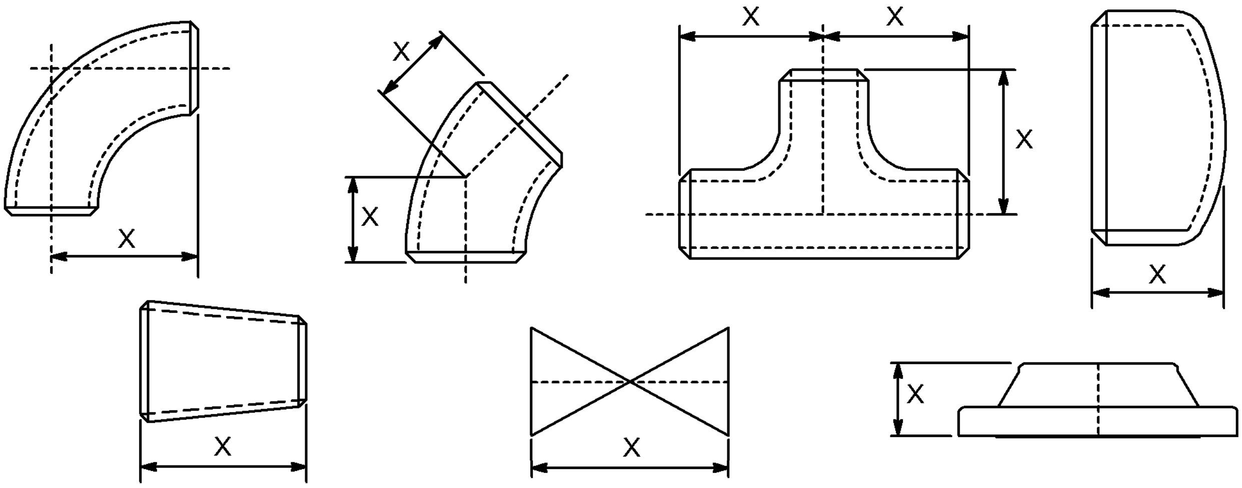
(12) **JF (E)**

Enter the longitudinal joint factor of the pipe. Determine the JF (E), using the most stringent value from Numbered Document A-11 and 49 CFR 192.113.

(13) **Footage to be Tested**

Enter the footage of pipe to be tested. Include the overall length of fittings in the footage to be tested. Steel fitting measurements should be taken to the center line of the fittings, as opposed to the inside or outside radius or tangent length. For reducers, measure to the larger diameter end of the reducer. The schematics below illustrate the correct measurements for fittings:

Attachment F, continued



(14) **Actual Footage**

The person supervising the test must enter the actual footage of the pipe section, even if it is the same as the footage entered by the originating engineer/estimator. Fitting lengths are included in the overall footage of pipe being tested. For existing facilities where pipe specifications and lengths are determined in the Materials of Record, enter "MOR" to indicate that the validation is based on the MOR and not on a visual inspection.

(15) **Location Class**

Determine the location class (described in 49 CFR 192.5). List all existing locations involved in the pressure test. If one pipe specification passes through multiple class locations, list all classes, separated by commas.

(16) **Most Restrictive Design Factor**

Determine the **most restrictive** of all of the factors, according to 49 CFR 192.111, for the various location classes and other engineering or code considerations. For example, one pipe specification that traverses class 1, 2, locations, but is caseless and crosses the right-of-way of a hard surfaced road—would have a most restrictive design factor of 0.50.

(17) **% of SMYS at MAOP**

This value is obtained from the hoop stress equation. Let stress at any given pressure P_1 be denoted by S_1.

$$\text{Then,}\quad S_1 = \frac{P_1 D}{2t}$$

$$\text{by definition, }\%\ SMYS\ at\ P_1 = \frac{S_1}{SMYS} \times 100$$

$$\text{Therefore, }\%\ SMYS\ at\ P_1 = \frac{P_1 D}{2t(SMYS)} \times 100$$

Where:
- P_1 = specified pressure (psig)
- D = outside diameter (inches)
- S_1 = stress at any pressure P_1 (psi)
- SMYS = specified minimum yield strength of pipe being tested (psi)
- t = pipe wall thickness (inches)

Substitute the MAOP in the equation above as P_1

(18) **% of SMYS at Minimum Test Pressure**

Substitute the minimum test pressure at maximum elevation (Box [1A]) in the equation above as P_1.

(19) **% of SMYS at Maximum Test Pressure**

Substitute the maximum test pressure at minimum elevation (Box [1B]) in the equation above as P_1.

Attachment F, continued

NOTE: For some older pipe, a longitudinal joint factor must be included when performing the calculations (see Numbered Document A-11). A temperature derating factor must also be used if the gas temperature exceeds 250°F (see 49 CFR 192.115). Contact Pipeline Engineering when either of these conditions occurs.

(20) **All fittings included in the test (except those listed above) are the same wall thickness and grade as the line pipe**

If the steel fittings (elbows, tees and caps) are the same grade and wall thickness as the line pipe, check the box. If the grade or wall thickness is different, list all information on a separate row in the **Pipe to be Tested** table.

(21) **Pipe specs verified in field**

For all new pipe installations, the person supervising the test must verify (where possible) the outside diameter, wall thickness, specification, SMYS, and seam type of each pipe section being tested in the field. After verifying all possible pipe sections, the test supervisor must indicate that the verification is complete by checking the box in this field.

(22) **Signature of person supervising test**

After verifying the pipe specifications, the PG&E test supervisor or qualified/certified contractor test supervisor must sign this field.

(23) **Component(s) limiting test pressure/Control Point exceptions**

Indicate any components that limit the maximum test pressure of the pipeline being tested to ensure that the test does not risk damaging those facilities. Valves and fittings may be the factor that limits the test pressure. For some existing pipelines, the limiting factor might be the mill test pressure when purchased.

The control point is most often at the minimum elevation. If there are sections of pipe with different specifications or strengths or other limiting facilities, then the control point might be at a higher elevation. Explain that exception here.

ffl **TEST SPECIFICATION:**

(1) **Test Factor**

The test factor is the multiplier that is applied to the desired MAOP or Design Pressure to determine the Minimum Test Pressure. For example, the test factor is 1.5 for pipe with an MAOP of 30% or more. Determine the test factor by referring to the **Minimum Test Pressure** row of Table A-1 in Numbered Document A-34, Attachment A, "Test Requirements." Read all associated notes.

(2) **Minimum Test Pressure at Maximum Elevation** [Box 1A]

Determine this value by multiplying the value in the **Test Factor** field by the value in the **MAOP to be Established by this Test** field. Also refer to the **Minimum Test Pressure** row of Table A-1 in Numbered Document A-34, Attachment A, "Test Requirements," and read all associated notes. For all pipelines 6" or larger, designed to operate at more than 40% of SMYS, consideration should be given to test to a minimum of 90% of SMYS, and as close to 100% of SMYS as practical. Tests of ERW pipe should be limited to a maximum of 95% of SMYS. Testing to this level allows continued operation at an established MAOP, if a class location change occurs.

The entire pipeline must be tested to a pressure greater than or equal to the required minimum test pressure, taking into consideration adjustments in pressure due to the static head of the test medium as a result of elevation differences.

NOTE: The static head, due to elevation difference, must not:

ffl Cause the pressure at the lowest point in the test section to exceed the pressure that produces a stress level equal to the yield strength of the pipe being tested.

ffl Prevent the pressure at the highest elevation from reaching the required pressures for a successful test.

Attachment F, continued

(3) **Maximum Test Pressure at Minimum Elevation** [Box 1B]

Determine this value by referring to the **Maximum Test Pressure** row of Table A-1 in Numbered Document A-34, Attachment A, "Test Requirements." Read all associated notes and, if necessary, adjust to create a practical test range. Ensure that the pressure range is sufficient to permit variations in the test pressure due to elevation, temperature changes during the test, or equipment problems/limitations.

Where an elevation difference exists, the maximum test pressure occurs at the lowest elevation point in the test section. The **control point** is most often at the minimum elevation. If there are sections of pipe with different specifications or strengths or other limiting components, then the control point might be at a higher elevation. Explain this exception in the **Components limiting test pressure/Control Point exceptions** field in Part 1 of the STPR.

CAUTION: The test pressure for any pipeline must not be greater than the pressure which produces a hoop stress of 100% of SMYS of the pipe, regardless of the strength of the valves, regulators, and similar equipment. If the MAOP of the pipeline cannot be established without exceeding the rated pressure of the equipment, consult Pipeline Engineering.

(4) **Spike Test Fields**

Complete the spike test fields [Boxes 1C, 1D, 1E, 1F] only for strength tests that include a spike test.

(5) **Spike Factor** [Box 1C]

A spike test requires the minimum test pressure at maximum elevation to be increased by approximately 10% and held for 30 minutes. Enter the spike factor that represents this percentage. A factor of 1.1 (10% above the minimum test pressure) is preferable. However, if the resulting spike pressure at minimum elevation [Box 1E] exceeds the maximum test pressure at minimum elevation [Box 1B], then the spike factor should be lowered until the spike pressure at minimum elevation [Box 1E] does not exceed the maximum test pressure at minimum elevation [Box 1B].

If after allowing for elevation differences and an acceptable pressure range between maximum and minimum pressures, a spike test is not possible, provide an explanation in Part 1 of the STPR, and notify Gas Transmission's Regulatory Compliance and the CPUC's Consumer Safety Protection Division (CPSD).

(6) **Spike Pressure at Maximum Elevation** [Box 1D]

Determine this value by multiplying the value in the **Min. Test Pressure at Max. Elevation** field [Box 1A] by the value in the **Spike Factor** field [Box 1C]. Round up to the next psig.

(7) **Spike Pressure at Minimum Elevation** [Box 1E]

Adjust for elevation differences by calculating the spike pressure at minimum elevation:

Spike Pressure at Max Elevation [Box 1D]	+	*Static head due to elevation difference between the maximum and minimum elevations in the test section*

NOTE: The resulting value cannot exceed the value in the **Maximum Test Pressure at Minimum Elevation** field [Box 1B]. If this occurs, lower the value in the **Spike Factor** field [Box 1C] accordingly.

(8) **Maximum Post-Spike Pressure at Minimum Elevation** [Box 1F]

After the spike test, the spike pressure at minimum elevation must be reduced by at least 5% to the desired test pressure for the remainder of the required test duration. Determine this value by multiplying the value in the **Spike Pressure at Minimum Elevation** field [Box 1E] by 0.95. This becomes the new maximum, or pressure ceiling, which cannot be exceeded for the duration of the test. A desired test pressure for the remainder of the test must be between the minimum pressure at maximum elevation and the maximum post-spike pressure at minimum elevation.

Always round the post-spike pressure down to the next psig.

NOTE: If the spike pressure is reduced such that the difference between the minimum test pressure at maximum elevation and the maximum post-spike pressure at minimum elevation is less than 30 psig, a spike test may not be feasible.

Attachment F, continued

(9) **Test Medium to be Used**

Determine the required test medium by referring to the **Test Medium** row of Table A-1 in Numbered Document A-34, Attachment A, "Test Requirements." Read all associated notes.

(10) **Minimum Test Duration**

Facilities being tested that are designed to operate at pressures under 30% of SMYS must be tested for a minimum of 1 hour. If they are to operate at pressures over 30% of SMYS, they must be tested for a minimum of 8 hours. The duration of the spike test is included in this minimum test duration; it is not added to the minimum test duration. For example, an eight-hour test with a spike test includes a 30-minute spike with at least a seven-and-a-half-hour test. Refer to all notes in Numbered Document A-34, Attachment A, "Test Requirements."

ffl **SIGNATURES:**

Non-erasable ink must be used for all signatures.

(1) **Prepared by (signature), Print Name and Phone Number, Date, LAN ID**

The individual preparing the report must sign the report. Also, legibly print name and phone number, date of test design completion, and LAN ID.

(2) **Approved by (signature), Print Name, Date, LAN ID**

The PG&E or contract project engineer (engineer of record) approving Part 1 of the form must sign it. Also, legibly print name, date, and LAN ID. (The person preparing the report cannot sign off as the approver. If the project engineer prepares the report, then the supervisor must approve it.)

(3) **Test Supervised by (signature)**

The individual supervising the test must sign both Part 1and Part 2 of the report. See Part 2 of the instructions for details.

(4) **Time and Date Pressure Reached, Time and Date Test Ended, Actual Duration of Test**

To ensure a connection between Part 1 and Part 2 of the report, the person completing Part 2 must copy this test data into Part 1. See Part 2 of the instructions for details about these fields.

2.Part II – Test Data

This section must be completed by the supervisor conducting the test in the field.

ffl Establish the location of the test point and then revise the pressure requirements due to the static head, if applicable, in reference to the test point. Also be sure to check the design sketch and all the relevant calculations in the design (Part 1) before starting the test.

ffl Identify all Operator Qualification (OQ)–covered tasks included within the work scope, and ensure that assigned personnel (including yourself) have the required operator qualifications to perform the work.

ffl Make a copy of the test report and complete it in the field, accurately recording the results of the pressure test, and then approving the test results data.

ffl Verify the specifications in the **Pipe to be Tested** table in Part 1, and check the verification box before starting the test.

IMPORTANT: Any changes from the requirements specified in Part 1 of the STPR, which result from unexpected field conditions, must be approved by the person approving Part 1 of the report

A. **Sheet ___ of ___**

Enter the page number of the form and the total number of pages in the form (e.g., 1 of 2). An STPR has at least two pages, Part 1 and Part 2. Each part might consist of multiple pages.

B. **Test Number ___ of ___**

Specify the unique identifier associated with the test. One job packet may include more than one test. Enter the test number in the following format: 1 of 5.

Attachment F, continued

C. **STPR Revision Number**

Enter 0 for the first version of the STPR. If the form needs to be revised due to a change in test criteria, enter the appropriate revision number, such as 1, 2, etc.

ffl **TEST ELEVATION:**

(1) **Elevation at Test Point**

Enter the elevation of the point where the test pressure recording device(s) is to be installed. Round up to the next foot.

(2) **Maximum Elevation in Test Section**

Enter the maximum elevation of the section of pipe being tested. Round up to the next foot. Generally, this is the value recorded when the test was designed. Or it can be an "as-built" value taken from a survey that was completed after the test design. If the maximum elevation of the test section is different from the value recorded in Part 1, do not change the value in Part 1.

Always complete this field, regardless of whether there is an elevation change.

NOTE: The maximum elevation of the test section might be at the maximum elevation of the test head.

(3) **Minimum Elevation in Test Section**

Enter the minimum elevation of the section of pipe being tested. Round down to the next foot. Generally, this is the value recorded when the test was designed. Or it can be an "as-built" value taken from a survey that was completed after the test design. If the minimum elevation in the test section is different from the value recorded in Part 1, do not change the value in Part 1.

Always complete this this field, regardless of whether there is an elevation change.

(4) **Static Head Between Test Point and Maximum Elevation** [Box 2A]

Calculate the static head between the test point and the maximum elevation of the pipe:

Maximum Elevation in Test Section (ft) – Elevation at Test Point (ft) = Elevation Difference (ft)

Elevation Difference (ft) x 0.433 (psig/ft) = Static Head (psig)

Always round the static head value up to the next psig.

(5) **Static Head Between Test Point and Minimum Elevation** [Box 2B]

Calculate the static head between the test point and the minimum elevation of the pipe:

Elevation at Test Point (ft) – Min. Elevation in Test Section (ft) = Elevation Difference (ft)

Elevation Difference (ft) x 0.433 (psig/ft) = Static Head (psig)

Always round the static head value up to the next psig.

ffl **NO SPIKE TEST: CALCULATIONS AND TEST RESULTS**

Complete this section for strength tests that do not include a spike test.

(1) **Minimum Required Test Pressure at Test Point**

This value is derived by adjusting the minimum test pressure at maximum elevation (as determined in Part 1) to account for the static head between the test point and the maximum elevation. Calculate by adding the static head:

Min. Test Pressure at Max. Elevation (Part I) [Box 1A] + *Static head between Test Point and Max. Elevation [Box 2A]*

Attachment F, continued

(2) **Maximum Allowable Test Pressure at Test Point**

This value is derived by adjusting the maximum test pressure at minimum elevation (as determined in Part 1) to account for the static head between the test point and the minimum test elevation. Calculate by subtracting the static head:

Max. Test Pressure at Min. Elevation (Part I) [Box 1B] - Static head between Test Point and Min. Elevation [Box 2B]

(3) **Pressure Range During Test**

Enter the resulting allowable pressure range available during the test by calculating the difference between the maximum allowable and minimum required test pressures:

Max. Allowable Test Pressure at Test Point - Min. Required Test Pressure at Test Point

(4) **Minimum Test Pressure Indicated** [Box 2C]

Record the lowest test pressure indicated on the pressure recording device(s) at the test point. To ensure an acceptable test, the test pressure should be held a few psi above the required minimum to ensure that minor fluctuations do not drop the pressure below the minimum. This would require restarting the test period.

(5) **Maximum Test Pressure Indicated** [Box 2D]

Record the highest test pressure indicated on the pressure recording device(s) at the test point.

(6) **Calculated Minimum Test Pressure at Maximum Elevation**

ffl If the test pressure is recorded at the highest elevation in the test section, then enter the **Minimum Test Pressure Indicated** value in this field.

ffl If the test pressure is recorded at a point other than the highest elevation in the test section, then adjust for the static head:

Min. Test Pressure Indicated [Box 2C] - Static Head between Test Point and Max. Elevation [Box 2A]

(7) **Calculated Maximum Test Pressure at Minimum Elevation**

ffl If the test pressure is recorded at the lowest elevation in the test section, then enter the **Maximum Test Pressure Indicated** value in this field.

ffl If the test pressure is recorded at a point other than the lowest elevation in the test section, then adjust for the static head:

Max. Test Pressure Indicated [Box 2D] + Static Head between Test Point and Min. Elevation [Box 2B]

ffl **SPIKE TEST: CALCULATIONS AND TEST RESULTS**

Complete this section for strength tests that include a spike test.

(1) **Spike Pressure at Test Point**

This value is derived by adjusting the spike pressure at minimum elevation (as determined in Part 1) to account for the static head between the test point and minimum elevation. Calculate by subtracting the static head:

Spike Pressure at Min. Elevation (Part I) [Box 1E] - Static head between Test Point and Min. Elevation [Box 2B]

(2) **Minimum Required Test Pressure at Test Point**

This value is derived by adjusting the minimum test pressure at maximum elevation (as determined in Part 1) to account for the static head between the test point and maximum elevation in the test. Calculate by adding the static head:

Min. Test Pressure at Max. Elevation (Part I) [Box 1A] + Static head between Test Point and Max. Elevation [Box 2A]

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Attachment F, *continued*

(3) **Maximum Post-Spike Pressure at Test Point**

This value is derived by adjusting the maximum post-spike pressure at minimum elevation (as determined in Part 1) to adjust for the static head between the test point and minimum elevation. Calculate by subtracting the static head:

Max. Post-Spike Pressure at Min. Elevation (Part I) [Box 1F] - Static head between Test Point and Min. Elevation [Box 2B]

(4) **Pressure Range After Spike Test**

Enter the resulting allowable pressure range available after the spike test by calculating the difference between the maximum post-spike and minimum required test pressures:

Max. Post-Spike Test Pressure at Test Point - Min. Required Test Pressure at Test Point

(5) **Spike Pressure Indicated** [Box 2E]

Record the highest test pressure indicated on the pressure recording device(s) at the test point during the spike test.

(6) **Minimum Test Pressure Indicated** [Box 2F]

Record the lowest test pressure indicated on the pressure recording device(s) at the test point. To ensure an acceptable test, the test pressure should be held a few psig above the required minimum to prevent minor fluctuations from dropping the pressure below minimum. This would require restarting the test period.

(7) **Maximum Post-Spike Test Pressure Indicated** [Box 2G]

Record the highest test pressure indicated on the pressure recording device(s) at the test point after the spike test.

(8) **Calculated Spike Pressure at Minimum Elevation**

ffl If the test pressure is recorded at the lowest elevation in the test section, then enter the **Spike Pressure Indicated** value in this field.

ffl If the test pressure is recorded at a point other than the lowest elevation in the test section, then adjust for the static head:

Spike Pressure Indicated [Box 2E] + Static Head between Test Point and Min. Elevation [Box 2B]

(9) **Calculated Minimum Test Pressure at Maximum Elevation**

ffl If the test pressure is recorded at the highest elevation in the test section, then enter the **Minimum Test Pressure Indicated** value in this field.

ffl If the test pressure is recorded at a point other than the highest elevation in the test section, then adjust for the static head:

Min. Test Pressure Indicated [Box 2F] - Static Head between Test Point and Max. Elevation [Box 2A]

(10) **Calculated Maximum Post-Spike Pressure at Minimum Elevation**

ffl If the test pressure is recorded at the lowest elevation in the test section, then enter the **Maximum Post-Spike Test Pressure Indicated** value in this field.

ffl If the test pressure is recorded at a point other than the lowest elevation in the test section, then adjust for the static head:

Max. Post-Spike Test Pressure Indicated [Box 2G] + Static head between Test Point and Min. Elevation [Box 2B]

Attachment F, continued

ﬄ **TEST ACCEPTANCE:**

(1) **Were Leaks Observed? (Yes/No)**

Indicate whether any leaks occurred during the pressure test. If yes, explain the leaks that occurred, including pressure loss, duration of pressure loss on new or existing pipe, equipment failure, loose fittings, etc. Also describe the action taken, if any, to repair the leak(s). The presence of leaks does not necessarily make a strength test unacceptable, particularly when the sources of leaks are known and observable, such as screwed fittings, flanges, etc.

Buried and aboveground pipeline hydrotest segments must be monitored for visible leaks throughout the test period. During the initial pressurization and hold period (i.e., while pressure is constant and the pump is not being operated), aboveground piping and connections must be checked for leaks. If no leaks are observed, but a decrease in pressure is observed during the hold period, attempts should be made to determine whether the diminishing pressure is due to a leak(s) or temperature. Some pressure decay will occur initially, but the decay will continue if caused by a leak, whereas the pressure tends to level-off if the cause is temperature.

Efforts to repair minor leaks from mechanical connections in the test segment should be attempted if the repairs can be accomplished safely. However, minor leaks will not necessarily invalidate a test, provided the leaks observed remain minor in nature and do not affect the ability to maintain the minimum required test pressure for the required test duration. During the required test duration, the pressure in the test segment must be constantly monitored and maintained within the specified test limits. If it is required to add water to maintain pressure within the specified test limits, the volume of water added should be monitored along with the associated pressure at the time water is added.

The observed leaks and their locations must be recorded and repaired upon completing the test, dewatering, and performing drying operations. Immediately after pressurizing the test section to place in service, each observed leak location must be leak-tested at full line pressure to ensure that the cause of the leak was properly repaired and the pipe is ready for service. Leak locations that do not pass the leak test must be repaired and re-tested until fully corrected.

If the cause of the constant decrease in pressure cannot be attributed to temperature change or leaks after placing the test section in service, the test section must be leak-surveyed with approved leak detection equipment to rule out the existence of a potentially hazardous leak. Once discovered, the leak must be repaired.

(2) **Acceptable Strength Test? (Yes/No)**

Indicate whether the strength test was successful. A successful hydrostatic test means:

ﬄ Reaching the pressure level required to validate the desired MAOP (and spike pressure, if required), and holding at least that level of pressure for the required test duration indicated in Part 1 of the STPR.

ﬄ Each potentially hazardous leak has been located and eliminated.

If the test was unsuccessful, fully describe the exact results of the test. Only the PG&E test supervisor or qualified/certified contractor test supervisor can determine whether the strength test was successful.

In case of a pipe failure when conducting the strength test, make sure that the failure is properly and fully reported as follows:

a. When strength-testing a pipeline to be operated at a hoop stress of 20% or more of SMYS, any failure must be reported to **Gas Control at 800 811-4111 within 1 hour of the failure if media is on site and within 2 hours if media is not present.** Provide as much information as available to Gas Control, as required by Utility Standard TD-4413S. Complete the "CPUC Pressure Test Failure Report." form and send it to the Regulatory Compliance department for submission to the CPUC.

b. A **detailed follow-up report** is required for all test failures, describing the nature of the fault that caused the failure (for example, failed girth weld, failed pipe seam, loss of metal due to corrosion, mechanical damage, etc.) Also provide details of actions taken to resolve the faults, enabling the re-testing of the pipeline. When the failed length of pipe and/or its appurtenances are replaced, the failed pipe and its appurtenances must be saved for further investigation by the Pipeline Engineering department for supplementary reporting to regulatory agencies. It is recommended that photos of the failure be taken and sketches made, to complement the write-up, for a traceable, verifiable, and complete record, which is required by the regulatory agencies.

Attachment F, continued

c. The **supplementary report** of the failure must be sent to the Regulatory Compliance department for submission to the CPUC.

d. Save all STPRs related to the test failure, as required by the **General** section at the beginning of these instructions.

e. Use PG&E Chain of Custody for handling all failed pipe testing. Refer to Utility Procedure TD-4100P-14, “Removing, Documenting, and Preserving Gas Transmission Pipe and Components.”

(3) **Test Medium Used**

Specify the medium used to perform the strength test.

(4) **Time and Date Test Pressure Reached**

Review the log and/or chart and identify the date and time when the minimum test pressure or the spike pressure is reached and remains above the value in the **Minimum Required Test Pressure at Test Point** field. Enter the time using military time format, e.g., 0810. Enter the date using month/day/year format, e.g., 02/13/2012.

NOTE: Copy the time and date into the **Time and Date Pressure Reached** field in Part 1 of the form.

(5) **Time and Date Test Ended**

Review the log and/or chart and indicate the date and time when the pressure test has met the minimum test duration requirement. Enter the time using military time format, e.g., 1630. Enter the date using month/day/year format, e.g., 02/13/2012.

Testing must never take less time than that specified in Part 1 and must be continuous for the required time period. Any drop of test pressure below the required minimum test pressure represents a termination of the test. The facility must be retested for the entire required time period.

It may be desirable to maintain the test pressure approximately 10 minutes longer than the minimum required in Part 1. This could avoid questions concerning chart or timing errors.

NOTE: Copy the time and date into the **Time and Date Test Ended** field in Part 1 of the form.

(6) **Actual Duration of Test**

Calculate the actual duration of the test, based on the log or chart.

NOTE: Copy the test duration into the Actual Duration of Test field in Part 1 of the form.

ffl **TEST INSTRUMENTS:**

(1) **Make, Range, and Serial Number of Pressure Recording Device/Dead Weight Tester**

Record the information about the pressure recording gauge and dead weight tester (if used) during the test. A dead weight tester (DWT), or electronic pressure recorder, is required for tests of any pipe segment equal to or greater than 90% of SMYS. (For the test chart requirements, refer to “General Information” Item 9 in Numbered Document A-34.)

IMPORTANT: Electronic pressure recorders must record pressure at a minimum of every 15 seconds and print the pressure recordings in intervals no greater than 15 minutes. The log of the DWT reading must be made every 15 minutes. Submit both pressure recordings with this form. The DWT log will be considered the official record of the test. But if the latter fails during the test, the pressure recording chart may be accepted as the official test record, provided that the recording chart has been correlated to the DWT at the beginning of the test.

NOTE: For non-DWT tests, a log of pressure recordings every 15 minutes is advantageous but not required.

(2) **Date Last Calibrated**

Enter the instrument’s last calibration date, which includes primary (official) or secondary (backup) records. The recorder must be calibrated within 1% accuracy every 6 months. Dead weight testers must be calibrated within 0.5% accuracy every 12 months. The recorder and DWT calibration records must be checked for compliance before conducting the test.

Attachment F, continued

ffl **SIGNATURES:**

Non-erasable ink must be used for all signatures. Before signing, the test supervisor and test approver must verify that all fields are complete and all calculations are accurate.

(1) **Test Supervised by (signature)**

The person supervising the test (a PG&E test supervisor or qualified/certified contractor test supervisor) must legibly sign the report and print name, date, and LAN ID. The signer must be the same test supervisor who signed the **Pipe specs verified by** field in Part 1. The form must be signed in the field at the time of the test. The signature must not be entered by a clerk at a later date.

NOTE: The test supervisor must also sign the **Test Supervised by** field in Part 1.

(2) **Testing Contractor (if third party)**

If a contractor conducted the test, enter the name of the contractor conducting the test in this field.

(3) **Approved by (signature)**

The PG&E construction supervisor is accountable for the test, regardless of who actually performed the test. Contractors cannot approve the test. The approver must legibly sign the report and print name, date, and LAN ID.

ffl **ATTACHMENTS:**

Ensure that the following documents are attached to the STPR and include the job number, test number, and any reference numbers:

(1) Test chart (For the test chart requirements, refer to "General Information", Item 9 in Numbered Document A-34.) You may also consider including anomalies encountered during the test, such as leaks and repairs, bleeding, etc.

(2) Schematic sketch of the pressure test design that contains the following information:

ffl The location and line number of the facility tested and the location of the test (e.g., at the site or in the yard).

ffl The minimum, maximum, and test point elevations (in feet) and their respective locations in the test section.

ffl Mile points or engineering stations and valve numbers and their relation (in feet) to known physical features (e.g., streets, highways, rivers, property lines, GPS co-ordinates).

ffl Piping, equipment, fittings, etc., included in the test section. The sketch should be accurate enough to detail the entire system under test, including flanges, valves, insulating fittings, buried instrumentation lines, etc.

ffl Fully identify the location of all tie-in pieces within the test section, or note if tested separately.

NOTE: If the person preparing the STPR included a sketch, this sketch must be verified in the field and corrected, as necessary, to represent the actual test setup. The sketch should also include information on the job number and the time and date of the test.

(3) Test log (if applicable) with pressure noted every 15 minutes. Include the following columns:

ffl Time

ffl Dead Weight Pressure

ffl Recorder Pressure

ffl Gauge Pressure

ffl Temperature (if applicable)

ffl Remarks

ffl **DISTRIBUTION OF STPR WITH JOB PACKET:**

Maintain a copy in the field office and distribute the STPR to:

Gas Job Closeout Desk, 6121 Bollinger Canyon Road, Building Z1, San Ramon, CA 94583