TAB 11

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
ACTIONS TO PROMOTE SAFETY ON PG&E'S GAS TRANSMISSION SYSTEM, AND ON LINE 132 SPECIFICALLY

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This chapter responds to Directives 3 and 4 of the OII. Directive 3 asks PG&E to "[p]rovide a summary of actions PG&E took between 1955 and September 8, 2010 to promote safety with respect to its natural gas transmission pipelines in general and San Bruno's line 132 in particular." While Directives 3.A-3.C and 3.E call on PG&E to explain its system-wide actions to promote safety, parts of Directive 3 (particularly Directive 3.D) focus on PG&E's actions with respect to Line 132. Directive 4 asks PG&E to list, identify and describe the types of historical documents and other information the Company has used to make safety risk assessments on its transmission lines between 1990 and 2010.

The response to Directives 3 and 4 is organized into four Chapters. Chapter 6A responds to Directives 3.A-3.C, summarizing the actions PG&E took to promote safety with respect to the construction, design and initial testing of its transmissions lines. Where industry or regulatory standards, or PG&E's practices, changed over time, PG&E explains those changes to give context. In many instances, PG&E has drawn upon older records, including past safety-related reports to Commission staff, to explain its past gas safety practices.

Chapter 6B also responds to Directives 3.A-3.C, and provides a similar overview of the actions PG&E took to promote safety with respect to the operations and maintenance of its gas transmission system. Like Chapter 6A, this chapter frames the discussion around the regulatory context. It describes ongoing maintenance and operations activities and provides an historical perspective of past actions and programs to promote safety within PG&E's gas transmission operations and maintenance.

Chapter 6C addresses two closely linked directives, both related to system-wide written safety risk assessments of transmission pipe: Directives 3.E and 4. In Directive 3.E, the Commission directs: "Provide all written safety risk assessments that PG&E conducted between 1955 and August 2010 on any and all transmission pipes in its system during that time." In Directive 4, the Commission further directs PG&E as follows: "Between 1990 and 2010, in conducting safety risk assessments on its transmission lines, for purposes of deciding whether to replace portions of the line, list and identify, and describe, the types of historical documents and other information that PG&E used to make its assessments (e.g. as built documents, operational pressures)."

Chapter 6C provides a narrative response to these directives, including a discussion of how PG&E's pipeline safety risk assessment practices developed over time. It then refers the Commission to written safety risk assessments that are being provided as part of this submission, and, for the period from 1990-2010, lists, identifies and describes the kinds of historical documents that were used to make the written safety risk assessments.

Finally, Section 6D responds to Directive 3 (and specifically 3.D) as it relates to Line 132 and explains the actions that PG&E has taken on Line 132 to promote safety from 1955 to 2010. Because these directives (Directives 3 & 3.D) focus on actions taken on a particular transmission line, as opposed to system-wide or programmatic actions, PG&E's response is more granular. It explains in detail discrete actions to promote safety on Line 132 over the past 55 years and includes written safety risk assessments relating specifically to that line. In many instances, the explanation draws upon historical pipeline records.

The scope of activities that promote safety, and thus that respond to Directive 3, is not well defined in the OII. To assure a comprehensive response, PG&E has attempted in each of these chapters to link categories of activities described in the directives to Subparts of Part 192 of the federal regulations. Thus, for example, when explaining its historic operations practices, PG&E has organized its response around the main categories of activities described in subpart L of Part 192 (Operations). Likewise, when explaining its historic maintenance practices, PG&E has organized its response around the main categories of maintenance activities described in subpart M (Maintenance). The point is not to suggest that PG&E takes only those safety actions described in Part 192, but rather to provide a structure around which to organize this response.

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6A
PG&E'S DESIGN, CONSTRUCTION, AND INITIAL TESTING PRACTICES AND PROCEDURES TO PROMOTE SAFETY

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CHAPTER 6A
PG&E'S DESIGN, CONSTRUCTION, AND INITIAL TESTING PRACTICES AND PROCEDURES TO PROMOTE SAFETY

A. PG&E Has Designed, Constructed, and Initially Tested its Transmission Pipelines Pursuant to Company Standards and Practices Written to Promote Safety and Fulfill State and Federal Requirements

This Chapter responds to Directives 3.A-3.C of the OII, describing the actions PG&E took within the areas of design, construction and initial testing to promote the safety of its gas transmission pipelines between 1955 and 2010. The Chapter focuses on PG&E's safety-related standards and practices corresponding to the pertinent federal regulations found in 49 C.F.R. § 192 subparts A (General), B (Materials), C (Pipe Design), D (Design of Pipeline Components), E (Welding of Steel in Pipelines), G (General Construction Requirements for Transmission Lines and Mains), I (Corrosion Control), and J (Testing).

To respond to the OII's directives, this Chapter provides a historical perspective as well as a description of PG&E's current standards and practices. The discussion is divided into two time periods: before and after state pipeline regulations took effect in 1961. Written company procedures may pre-date and/or exceed regulatory requirements. As noted in Chapter 1A, a significant part of PG&E's gas transmission pipeline system was constructed before state regulation of gas pipelines took effect in 1961 (and a majority of it was installed before the enactment of federal regulations in 1970). During the time period before state regulation, PG&E undertook to promote safety by conforming construction practices and specifications to industry standards. Since 1961, PG&E's design, construction, and testing practices have been shaped by state, and later federal, safety rules.

1. Pre-1961 Design, Construction, and Testing Practices Undertaken to Promote Safety

It is difficult to recount details about pipeline design and construction practices more than 55 years after the fact. In this section, PG&E examines a selection of large pipeline projects undertaken in the 1950s about which the most is known. These projects provide a window into how PG&E designed and constructed pipeline in an era before pipeline safety regulations.

Faced with significant population growth and limited in-state natural gas reserves, PG&E began exploring construction of connecting pipelines (that today form PG&E's backbone transmission lines) to out-of-state suppliers in the late 1940s. PG&E's first connection to such a supplier came about in 1948 when PG&E applied for a Certificate of Public Convenience and Necessity to link its transmission network to gas-producing fields in New Mexico, Colorado, Utah, and Texas. This project involved constructing over 500 miles of pipeline between Topock and PG&E's Milpitas Terminal, with a delivery capability of 400 million cubic feet of natural gas per day. (P3-00001). The project was ambitious, calling for use of the largest pipe ever used in a gas transmission line to date – 34-inch main referred to as the "Super Inch" fabricated at the Consolidated Western Steel Corporation plant in South San Francisco. (P3-00002). The line had to cross the rugged terrain of the Mojave Desert and Tehachapi Mountains. Contractors from Bechtel Corporation, Conyes Construction Company, and the H.C. Price Company completed installation of the line (now known as Line 300A) and three supporting compressor stations in Topock, Hinkley, and Kettleman by the end of 1951.

PG&E designed the Topock-Milpitas line with safety considerations, ratepayer interest, and pipeline capacity in mind. One way of harmonizing these interests was by "tapering" the wall thickness of particular sections of pipe. (P3-00003). Tapering took advantage of the natural change in the pressure gradient along the pipeline to allow the utility to install thick-walled pipe in areas designed to operate at high pressure, and thinner-walled pipeline in sections designed to operate at lower pressures due to their distance from compressor stations. The determining factor for establishing a change in the wall thickness of the pipe was the maximum allowable operating pressure (MAOP) of a particular section of the line. MAOP was determined by using a safety factor that was consistent with the class location of the section of pipeline. The class location was determined based on the population density along the pipeline. The MAOP of the pipeline was that which did not exceed the allowable percentage of specified minimum yield stress for its class location. Pressure limiting stations were installed upstream of reduced wall thickness sections to ensure that the MAOP of the pipeline would not be exceeded under line packing conditions (increasing the quantity of gas in the pipeline during off-peak periods to satisfy forecasted peak demands).

Over the next several years, PG&E filed supplemental applications to increase the capacity and reliability of the Topock-Milpitas line by installing parallel runs of pipe. (P3-00004). In 1955, PG&E filed one of these supplemental applications to install additional sections of parallel pipeline and a second crossing of the Colorado River. (P3-00005). PG&E constructed this line (now known as Line 300B) pursuant to newly-issued section 8 of the American Society of Mechanical Engineers' American Standard Association Committee B-31. (ASME B31.8). (P3-00006). This substantial revision was developed between 1952 and 1955 through the participation of utilities, steel suppliers, academics, and the Federal Power Commission, with the intent to establish a generally accepted standard across the country for safety in gas transmission and distribution work. PG&E participated in this effort.

In connection with hearings on PG&E's Third Supplemental Application, CPUC staff engaged in lengthy questioning of PG&E regarding construction practices in 1955. At a November 22, 1955 hearing, PG&E summarized its construction practices that were to be used in building the line:

- PG&E followed American Petroleum Institute (API) 5LX standards for procuring the pipe;[1]

[1] API pipe procurement standards require pipe to pass a variety of tests, including hydrotesting, bending, and chemical composition, before the pipe is shipped from the mill. These standards are discussed in more detail in section 2(b)(2) of this Subchapter.

- Pipe was to be tested hydrostatically at the mill;
- All welders on the project would be required to requalify pursuant to API Standard 1104;
- PG&E planned to conduct x-ray inspections of all tie-in welds, welds to fittings, and welds near river crossings, as well as between five and ten percent of all other girth welds. These inspections would be designed to inspect a sample of welds made by each individual on the project;
- Miter bends were not to be used in construction of the line;
- Significant dents and gouges were to be removed;
- Smooth bends were to be made on the job, but cold wrinkle bends were not to be allowed. All bends were to be at least two feet from any girth weld;
- All buried pipe was to be protected from external corrosion through primer paint, two coats of asphalt, and two layers of felt. This wrapping was to be inspected both in the yard where the pipe was stored before installation and on the job site;
- The line was to be protected using cathodic protection stations. Due to the protective qualities of the paint, asphalt, and felt coating, one station could protect between 40 and 50 miles of line;
- The line was to be cased where it crossed state highways and railways. Heavier pipe (thicker walls than required for the class location and MAOP) was to be used at secondary road crossings;
- The bottom of the trench dug for the line was to be free from rocks and other objects that might damage the pipe wrapping. Backfill was to be similarly free of harmful objects;
- The pipe was to be strength tested using gas or water as the test medium. In sections closer to the Milpitas Terminal, PG&E planned to conduct hydrotests to 125% of working pressure, as specified by ASME B31.8 section 841.412-D (1955). PG&E was also exploring the feasibility of conducting hydrotests in Class 2 locations, and planned to conduct such testing where practical; and

- Valves and blow-down facilities were to be spaced such that the longest it would take to blow down any section of pipe from maximum working pressure would be between 30 and 40 minutes.

(P3-00006). PG&E's plans for construction of the line were designed to exceed ASME B31.8 requirements to varying degrees. PG&E went beyond ASME B31.8 requirements in the frequent use of heavier (thicker-walled) pipe in areas where PG&E had reason to expect future urbanization, at river crossings, and in places with greater potential for corrosion activity. These construction practices were "on the conservative side," meaning they built in a safety margin beyond that called for by ASME B31.8.

PG&E also built the first of its northern backbone transmission lines (Line 400) during this pre-regulatory era. In the late 1950s, PG&E again forecasted that customer demand for natural gas would exceed the quantity of gas available to it from existing suppliers. To meet the growing demand, PG&E initiated a project to bring gas to California from Alberta, Canada. (P3-00007). At the time, the Commission was developing what would become the first General Order 112, but had not yet engaged in direct regulation of design, construction, and testing practices for natural gas transmission. PG&E's design, engineering, and construction of the pipeline was guided by standards set forth by ASME B31.8. These standards would soon be incorporated with modifications into state regulatory requirements.

2. PG&E Standards and Practices for the Design, Construction, and Initial Testing of Pipeline After 1961

a. Pipeline Design

(1) Regulatory History

The Commission adopted the 1958 ASME B31.8 with modifications when it first issued General Order 112. ASME B31.8 stated that the code was intended to assure that its design requirements were "adequate for public safety under all conditions usually encountered in the gas industry." GO 112 § 840.1 (RH-3). GO 112 includes a broad set of standards that can be categorized as applying to the design of natural gas transmission pipeline. These include establishing steel pipe design formulas (§ 841.1); guidelines for protecting pipeline from hazards such as landslides and erosion (§ 841.15); setting minimum cover standards (§ 203.1); and clearance between pipeline and other underground facilities (§ 841.161). These standards remained largely unchanged through GO 112-A (1963) (RH-4) and GO 112-B (1967) (RH-6).

Following implementation of federal laws and regulations for the natural gas industry, the Commission adopted GO 112-C (RH-32) in 1971 and incorporated federal pipeline safety standards. GO 112-C departed from the Commission's prior practice of implementing ASME B31.8, and instead incorporated the requirements of 49 C.F.R. Part 192. This practice continued through GO 112-D (RH-34) to the current GO 112-E (RH-36). Standards for pipe design in 49 C.F.R. 192, subpart C include design formula for steel pipe (49 C.F.R. § 192.105), design factor (§ 192.111), and general requirements for minimum wall thickness to withstand anticipated external forces and loads (§ 192.103).

(2) PG&E Standards and Practices

PGE adopted Standard Practice 1604 (S.P. 1604) to establish a uniform procedure for designing gas piping systems to meet the requirements of GO 112. This standard called for all new construction and reconstruction to meet design and pressure requirements set forth by the new regulation. (P2-902). This standard practice was superseded by PG&E Gas Standard and Specification A-34 in 1969 (A-34). (P2-903). A-34 is substantially the same as S.P. 1604. As revised over the last 41 years, A-34 is a primary guidance document for the design, construction, and initial testing of PG&E's natural gas transmission pipeline. Among other things, the standard requires that each transmission pipeline design be reviewed, approved, and signed by a professional engineer registered in California. (P2-36).

Starting with GO 112 in 1961, the Commission required all natural gas utilities to provide advance notice of transmission pipeline construction projects, including details regarding pipe design, construction, and planned hydrostatic testing. (RH-3). Archived PG&E records reflect the submission of many such reports to the Commission, in which PG&E provided the location, pipe specifications, and scheduled hydrotesting date to the Commission for transmission projects. (P3-00008, P3-00009, P3-00010). Over the years, the Safety Branch has observed PG&E's design and construction practices in the field, and has been present at some construction sites to inspect the pipeline and witness hydrotests.

Design and construction requirements are also specified in PG&E Gas Standard and Specification A-36 §§ 3-4 (1992) (P2-309). This document establishes general principles for many types of design and construction activities, including pipeline construction techniques in the trench, pipe handling, and inspection.

(3) Additional Design Practices that Promote Safety

PG&E has employed design and construction practices that go beyond those called for by state and federal regulation. These practices include particular methods used to address unique challenges presented by the varied geography of PG&E's service territory and proprietary tools used by pipeline engineers to design pipeline to withstand physical forces imposed by soil loading and vehicle traffic over the line.

(a) Addressing Design Challenges Presented by PG&E's Service Territory

Pipeline engineers are confronted with many challenging and unique circumstances presented by the geographic features present in PG&E's expansive service territory. One project that employed several additional design and construction practices to address unique geography was the construction of Transmission Line 57C that concluded in 2007.

Line 57C was built to parallel existing Line 57B connecting the McDonald Island storage field to PG&E's transmission network. These lines cross levee-protected islands in the Sacramento Delta. To avoid damaging the levee network during installation of the line, PG&E used horizontal directional drilling to string pipe underneath the levees and rivers in the Delta. This obviated the need to dig trenches across the levees.

Engineering analysis also revealed the potential for a levee failure to cause significant "scour," or soil erosion at the point of failure. PG&E determined the scour length for each location where Line 57C crossed a levee, and relocated the pipe or used additional horizontal directional drilling to place the pipe beyond the furthest extent of the scouring.

The soil surrounding Line 57C presented another challenge, as most of the soil within 12 feet of the surface consists of peat, and is considered a liquefaction zone in the event of a large magnitude earthquake. PG&E conducted additional engineering analysis to ensure that the pipe could withstand anticipated ground movement in such an event. One of the outcomes of this process was the decision to use manufactured induction bends that can better resist earthquake-induced ground movement.

As an additional safety measure, PG&E increased the wall thickness of pipe used in Line 57C to meet design specifications for a Class 3 location, even though most of the pipeline is in less-populated Class 1 or Class 2 areas.

(b) Proprietary Design Tools

For many of the last 55 years, PG&E pipeline engineers have used a proprietary tool known as PSTRESS to determine the effects of outside forces on the pipeline. The PSTRESS tool enables engineers to calculate stresses on buried gas pipeline subjected to any combination of the following types of loading: (1) hoop stress due to internal pressure; (2) circumferential bending stress due to traffic (vehicle and rail) load; (3) circumferential bending stress due to fill load; (4) longitudinal stress due to internal pressure; (5) longitudinal stress due to change in temperature; and (6) longitudinal bending stress due to pipe geometry and material mechanics. PSTRESS calculates total longitudinal and circumferential stresses based on user input of the pipe specification, trench configuration, internal gas pressure, and traffic loading. The calculations performed in

PSTRESS are based upon extensive academic research into the effect of loading on buried pipe.

PG&E has modified PSTRESS to more precisely address situations where the depth of cover on the pipe is relatively shallow (less than two feet). Where PSTRESS indicates that existing loading conditions are not within recommended tolerances, the engineer may call for additional fill over the pipe at locations where equipment will be crossing the line. Other mitigation options include placing a concrete slab or other form of bridge over the pipeline. Where none of these options are feasible, the engineer may relocate the affected area of pipeline.

b. Pipe Specification and Procurement

(1) Regulatory Requirements

Chapter 1 of GO 112 (1961) (RH-2) required pipeline operators to construct pipeline from qualified materials and equipment. The first category of "qualified" materials are those that conform to standards and specifications listed within the GO itself. § 811.1(a). Accepted standard specifications for materials, including line pipe, are set forth in Appendices A and B of GO 112, § 813.1. These appendices support the use of American Petroleum Institute (API) 5L and API 5LX material specifications for steel line pipe. Subsequent state and federal regulations have adopted API pipe specifications as qualified materials for the safe construction of pipeline.

(2) PG&E Standards and Practices

Following the implementation of state and federal regulations, PG&E's standards for transmission line pipe have called for API 5L and API 5LX line pipe. (P3-00011, P2-902, P2-903, P2-933, P2-939, P2-36). API standards cover welded and seamless pipe suitable for the conveyance of gas, water, and oil. These standards for pipe manufacturing require stringent testing and quality control to ensure that the highest quality pipe is used in a pipeline. API requirements address processes of manufacturing, material properties including chemical composition, tensile testing, and hydrostatic testing performed at the mill.

Line pipe specifications have evolved as PG&E's construction projects have utilized higher grade and larger diameter pipe. For example, PG&E's pipe specifications in SP 1604 (1965) included API 5L specifications for seamless and DSAW 35,000 psi SMYS pipe, API 5LX Grade X-42 42,000 psi SMYS pipe, and API 5LX Grade X-52 52,000 psi SMYS pipe. By 1974, PG&E's pipe specification requirements expanded to include API 5LX Grade X-60 60,000 psi SMYS and API 5LX Grade X-65 65,000 psi SMYS DSAW pipe for use in larger diameter applications. *See* A-34 Change 3 (1974) (P2-903).

PG&E currently requires all steel pipe purchased for use in its natural gas piping systems to meet API 5L[2] specifications. (P3-00012). This standard is annexed to procurement contracts, and governs conditions of acceptability. (P3-00013). The standard assures that mill-furnished pipe meets certain chemical properties (A-16 § 2), mechanical properties (§ 3), is inspected during the pipe production process by a PG&E Supplier Quality-designated inspector (§ 4), is hydrostatically and non-destructively tested (§§ 6-7), meets defect repair requirements (§ 8), is marked to facilitate traceability (§ 9), and is shipped in accordance with applicable PG&E standards (§ 10). PG&E A-16 requirements exceed the API 5L standard by calling for lower carbon equivalent requirement (0.40% compared to API at 0.43%), higher Charpy test values,[3] tighter tolerances for defect repairs and 100% inspection on each mill run.

c. Pipe Handling, Storage, and Transportation

(1) Regulatory Requirements

GO 112 provides the general guidance that "[c]are shall be taken in the selection of the handling equipment and in handling, hauling, unloading and placing the pipe so as to not damage the pipe." GO 112

[2] API discontinued the use of 5LX specifications in 1982. All grades of pipe are now incorporated in API 5L specifications.

[3] The Charpy impact test, also known as the Charpy v-notch test, is a standardized high strain-rate test which determines the amount of energy absorbed by a material during fracture. This absorbed energy is a measure of a given material's toughness and acts as a tool to study temperature-dependent brittle-ductile transition.

§ 841.271 (underlining in original). This requirement continued unchanged through the initial adoption of GO 112-B. An amendment to GO 112-B in 1970 incorporated 49 C.F.R. § 192.65, which provided that the transportation of certain pipe by rail must be done pursuant to API standards, or be pressure tested if the pipe were transported before 1970. This requirement was amended in 2010 to provide some additional transportation guidance for pipeline transported by ship or barge, again referring operators to API standards. See 49 C.F.R. § 192.65.

(2) PG&E Standards and Practices

PG&E currently implements requirements for transporting pipelines set forth in 49 C.F.R § 192.65 through Gas Standard and Specification A-14. (P3-00014). PG&E's standards and practices also expand upon regulatory requirements for the safe handling, storage, and transportation of pipe. (P3-00015). PG&E Standard Practice 522.1-2 (1963) (S.P. 522.1-2) established procedures to ensure that pipe was handled and stored in a manner to avoid damage to any part of the pipe or coating. Generally, S.P. 522.1-2 was meant to ensure that pipe did not sustain damage such as grooves, dents, gouges, or flattening while in transit between the mill and the trench. S.P. 522.1-2 (as well as its successors) also provides particular instruction in the stacking, loading and unloading, transportation, and storage of pipe.

PG&E standards articulate special handling instructions when placing the pipe into the trench in order to prevent damage to the pipe and coating. Current Gas Standard and Specification A-36 calls for specific clearances between pipe and trench walls. It requires construction personnel to clear the trench of rocks and other hard substances prior to laying the pipe, and for surrounding the pipe with backfill of sand or other fine materials to protect the pipe and protective coating from rocks and other sharp objects. (P2-309). This standard also calls for pipe to be transported into the trench using specialized lifting equipment to avoid bending, denting, buckling, scratching, or otherwise damaging the pipe.

d. Welder Qualification and Weld Inspection

(1) Regulatory Requirements

Pipeline safety laws have required each utility or operator to establish and qualify a welding procedure for use in constructing girth welds, and further specified that each welder must qualify under the procedure before working on transmission pipe. Generally speaking, natural gas utilities and operators could satisfy the requirement by creating a welding procedure that followed specifications of API Standard 1104, "A Standard for Field Welding Pipe Lines."

Regulations also have required natural gas utilities and operators to inspect welds on pipe intended to operate above 20% SMYS to ensure that the welds conform to standards of acceptability. The method of inspection was not originally specified, but could include nondestructive testing (visual, radiographic, or magnetic particle testing) and destructive testing. In 1961, California natural gas utilities and operators were required to test 100% of welds at tie-ins, infrastructure crossings, taps, and other required areas, 30% of welds in Class 3 and Class 4 locations, and 20% in Class 1 and Class 2 locations, all on a daily sampling basis to ensure that each welder's work was inspected. These standards changed in 1971 to require 100% inspection of welds in Class 3 and 4 locations if practical, but not less than 90%. (RH-32). Pursuant to GO 112-E and the incorporated federal regulations, California utilities and pipeline operators must currently inspect 10% of Class 1 girth welds and 15% Class 2 girth welds all on a daily sampling basis. Every Class 3 and 4 girth weld and each girth weld at an infrastructure crossing must be inspected unless impracticable, and in no case may less than 90% of these welds be inspected. See 49 C.F.R. § 192.243(d).

To pass inspection, welds must be free from certain types of defects specified in federal and state regulations. Tolerances for welding defects were first set out in GO 112 § 829, and are currently found at 49 C.F.R. § 192.241(c) (incorporating API 1104 § 9).

(2) PG&E Standards and Practices

PG&E standards have implemented the welding requirements set forth in state and federal regulations. PG&E issued Standard Practice 1602 (S.P. 1602) in 1963 to establish a uniform welding procedure for constructing girth welds. (P2-1271). This standard also set forth welder qualification requirements, tests, and inspection procedures for welding API 5L and 5LX pipe operating at or above 20% SMYS. These standards now appear in PG&E Gas Standards and Specifications D-22 (2009) (P2-10), D-30.2 (2009) (P2-1282), D-30.4 (2009) (P2-1285), and D-31 (2009) (P2-1270).

PG&E issued Standard Practice 1605 (S.P. 1605) (P2-1286) in 1963 to establish a minimum weld inspection procedure for all gas pipe systems and to satisfy inspection requirements set forth in GO 112. This standard called for welds to be inspected on a sampling basis sufficient to establish the performance of each welder, and in percentages that met the regulatory requirements. Requirements in S.P. 1605 are presently found in PG&E Gas Standard and Specification D-40 (2009) (P2-1296).

(3) PG&E Welding Apprenticeship Program

Certain of PG&E's training programs have been recognized in the past for their quality. (P3-00016). One training program PG&E has historically offered bears special mention. PG&E offers a welding apprenticeship for General Construction Arc Welders and training for Division Gas Fitters. The welding training shop is located in San Ramon. Through the "Power Pathways" program, which connects the Company to six community colleges, PG&E recruits graduates of community college welding programs. In addition to those recruits, field employees can also enter the apprenticeship program. The apprenticeship program is rigorous: It extends over 36 months and involves 6000 hours of in-the-shop and on-the-job training. PG&E now employs a training coordinator dedicated to the welding apprenticeship program who visits the welding apprentices in the field.

e. Initial Testing Requirements

(1) Regulatory Requirements

Regulations did not call for natural gas utilities to pressure test transmission lines until GO 112 in 1961. (RH-2). Federal regulations covering strength testing in 49 C.F.R 192, subpart J were incorporated by GO 112-C (1971) (RH-32) and remain in effect in current GO 112-E (RH-36).

(2) PG&E Standards and Practices

S.P. 1604 called for construction foremen to observe strength test requirements set forth by the responsible pipeline engineers, and record information from the actual test on a "Strength Test Report" to be returned to District Superintendents and other appropriate personnel. *See* S.P. 1604 (1965) (P2-902). This standard also specified the conditions under which strength tests were required and the test medium and pressure to be used. Strength testing requirements are presently set forth in PG&E Gas Standard and Specification A-34, and have been since 1969. The various versions of A-34 have called for strength testing to be carried out pursuant to the design pressure and class location as specified in GO 112. (P2-903).

TAB 13

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6B
OPERATIONS AND MAINTENANCE ACTIONS TO PROMOTE SAFETY ON PG&E'S GAS TRANSMISSION SYSTEM

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A. PG&E Has Sought to Operate and Maintain its Transmission Pipelines to Promote Safety.

This Subchapter responds to Directives 3.A-3.C of the OII. It describes the actions PG&E took within the areas of operations and maintenance (O&M) to promote safety on its gas transmission pipelines between 1955 and 2010.

This Subchapter sets the regulatory context and then describes, for each regulatory topic area, PG&E's operational and maintenance actions and procedures to promote safety. The discussion follows the organization of Subparts L and M of 49 C.F.R. Part 192. Subpart L sets forth the present-day regulatory standards that govern natural gas pipeline operations. Included in the discussion of operations are PG&E's Training and Operator Qualification Programs referenced in Subpart N. Subpart M sets forth the regulatory standards that govern maintenance activities, including repairs. PG&E's response generally tracks major O&M subject areas described in subparts L and M.[1] Although these subparts did not come into effect until 1970, they provide a framework for organizing a discussion of O&M actions and procedures during the entire time period covered by the OII.

1. Overview of O&M Regulatory Requirements

The Commission's adoption of GO 112, effective July 1961, introduced operations and maintenance regulatory requirements. Chapter V of GO 112 mandated the development of and adherence to a "plan covering operating and maintenance procedures" for day-to-day operations and emergencies and established requirements relating to patrolling, corrosion, leak repairs, valve inspection, odorization and operating pressure. In 1970, the Department of Transportation Office of Pipeline Safety (OPS) promulgated federal regulations for pipeline safety. In addition to the types of operational requirements included in GO 112, Subpart L of the new federal regulations addressed "Operations," a subject area that included line surveillance, emergency plans, and investigation of failures. Subpart M added maintenance requirements related to line markers, field repairs and testing

1 PG&E has not discussed every subject area in subpart L (e.g., it has not included a discussion of its procedures for tapping pipelines under pressure) or subpart M. It has, however, addressed most subject areas in subparts L and M.

of repairs, and abandonment of facilities. GO 112-E (and several predecessor GO 112s going back to 1970) adopt Part 192's subparts, including subparts L and M.

2. Operations Activities To Promote Safety

a. Damage Prevention and Public Awareness Programs

PG&E's efforts to prevent third party damage are critical to maintaining the safety of its gas transmission system. In its latest annual report, the Commission's Safety & Reliability Branch declared that in 2007, "the single most common cause of [] reportable gas incidents was excavations." (P3-10,001). The Safety Branch's report from a decade earlier reported that dig-ins caused about 60% of the reportable gas incidents for 1997. (P3-10,002).

Beginning in 1982, 49 C.F.R. § 192.614 required operators to implement programs to prevent damage to pipelines due to excavation. This regulation followed the general program recommendations of the American Petroleum Institute's Recommended Practice 1162. (Prior to 1982, the regulations did not require operators to maintain formal damage prevention programs). Since 1994, § 192.616 has required operators to develop and implement a written continuing public awareness program. Damage prevention and public awareness efforts are discussed together in this section.

PG&E's electronically accessible Damage Prevention Manual provides, in one location, regulatory and company damage prevention requirements, policies, and procedures for gas, electric, and fiber facilities. Principal elements of PG&E's Damage Prevention program include:

- Mark and Locate and the One-Call System
- Installation of Line Markers
- Public Awareness Program
- Collaboration with Outside Groups.

(1) Mark and Locate and the One-Call System

PG&E participates in a statewide "one-call" system—the Underground Service Alert (USA). This system allows contractors, homeowners, municipalities, utilities, and others to call one number (8-1-1) when they are planning to excavate anywhere in California. The USA service then alerts potentially affected utilities. The service generates and transmits to PG&E a “USA ticket” anytime someone is planning to dig near any PG&E facilities (including gas transmission, gas distribution, electric transmission and distribution, and fiber). Every year PG&E receives about 500,000 USA tickets, of which 300,000 require a response by the Company.

The tickets are processed by PG&E’s ticket handling software, which sends the ticket directly to a Company locator to respond. Locator personnel are equipped with mobile computers showing facility maps to allow them to respond quickly and efficiently to the tickets. Each ticket is screened by the locator to determine if PG&E facilities may be in conflict with the excavation, which would require surface marking, and determine if a field meeting with the excavator is necessary.

When surface marking is required due to a conflict, yellow paint is sprayed on the ground to mark the location of the facility, or another appropriate marker is used. After marking, PG&E may then contact the excavators for further information about the planned excavation as required. If work is expected to come within five feet of gas transmission facilities, PG&E’s procedures call for employees to be present at the location while the third party digs around the facility. No power equipment is permitted to operate within 12 inches of the gas transmission line.

PG&E has employed procedures meant to prevent damage to the Company’s pipelines throughout the time period covered by the OII, even if the practices were not set out in a formal damage prevention program. Some of these procedures have been described in correspondence with the Commission. In 1966, for example, the CPUC requested that PG&E describe the “most significant actions taken by PGandE in an effort to minimize the number of accidents and interruptions of gas service, which are or could be caused by others.” (P3-10,003). As PG&E described, its damage prevention procedures at the time included, among other things, providing information about the location of its gas facilities to individuals who requested it before beginning construction; using pipe locators and marking facilities in the field as needed when excavations were to take place; standing by at the project as needed; and exposing pipelines as needed to protect them. PG&E distributed wallet cards to excavators and members of the public with a telephone number to call to locate underground facilities or in the event of an emergency. The Company also exchanged information with governmental agencies and other utilities to avoid potential conflicts with other underground facilities. PG&E Report to CPUC, Operating and Maintenance Procedures for Major Gas Pipelines, section 8 (1966) (1966 O&M Report) (P3-10,004).

In this era, PG&E had a standard practice of requiring that at the time of installation adequate minimum ground cover be provided above gas mains. The amount of cover required might be greater, for example, in "areas where farming or other operations might result in deep plowing." PG&E Report to CPUC, Pipeline Surveillance Procedures and Records and History File Description Pipeline Patrolling, Standard 463-4 (1967 Surveillance Report) (P3-10,005). PG&E had also established an approach for working with landowners to ensure safety when the landowners planned to cultivate or level the ground near older facilities buried close to the surface. 1966 O&M Report, section 6 (P3-10,004). The Company employed a standard for "Use of Company Rights of Way (Fee and Easements) By Others," which addressed safety and legal issues relating to third party activities near pipelines. (P3-10,005).

In 1974, PG&E collaborated with the Pacific Telephone Company to develop an "information clearinghouse plan" that would establish a "one-number call system." (P3-10,006). The "clearinghouse plan" had a call center that would contact participating utilities by teletype about planned excavations that might affect their facilities. PG&E's implementation of an early one-call system in 1974 preceded regulatory requirements for a one-call program by a number of years.

(2) Line Markers

PG&E's transmission lines are installed with above-ground markers identifying their location. (Ex. P3-10,007). The markers include non-metallic marker posts, steel marker posts, pipeline warning decals (in English and Spanish), and aerial pipeline markers (for identification by aerial patrol aircraft). In addition, although not required by regulation, signs are placed at any location where PG&E's transmission lines traverse navigable waterways to alert vessel operators to the presence of the lines.

PG&E has long used "readily identifiable markers" on its pipelines to minimize damage caused by farmers, excavators, or others and to assist PG&E's own employees in finding pipelines in remote places like the desert. (P3-10,004). By 1955, PG&E practices specified the particular type of marker that would be used according to the location on a pipeline; the Company had developed design drawings for those markers, e.g., a "Steel Marker Post for Underground Gas Facilities." (P3-10,005). PG&E used this steel Marker Post line marker design since at least 1955.

(3) Public Awareness Program

An important component of PG&E's damage prevention program is making the public aware of the need to alert PG&E in the event of planned excavations. PG&E's Public Awareness Program is guided by several PG&E procedures:

- Risk Management Procedure 12. RMP 12 sets forth PG&E's plan to enhance public safety and environmental protection through increased public awareness and knowledge. (P2-398).
- Safety Health & Claims (SH&C) Procedure 103, Public Safety Information Program, directs the delivery of information to customers and the public regarding the safe use of electricity and natural gas and safety awareness around the company's gas and electric facilities. (P3-10,008, P3-10,009).