

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 2**  
**RECORD RETENTION REQUIREMENTS AND PRACTICES**

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## CHAPTER 2

### RECORD RETENTION REQUIREMENTS AND PRACTICES

The Duller/North Report criticizes PG&E's records retention standards and practices. Its findings and supporting analyses are scattered across three appendices (Appendices 3, 8, and 9) and several different report sections (6.2.3, 6.3.1, and 6.3.2). Collected together, these findings purportedly support the violations asserted in the Duller/North Supplement.

The Duller/North Supplement asserts a general records management violation (A.1), portions of which touch on records retention topics. In slightly more concrete terms, the Supplement asserts six records retention violations (B.1-B.6) across a varied range of time frames.<sup>1</sup> These six records retention violations are:

1. PG&E's alleged minimal compliance with some of its own retention policies regarding leak survey maps violates others requirements (April 2010 to September 2010).
2. PG&E's alleged minimal compliance with some of its own line patrol report retention policies violates other requirements (dates ranging from September 1964 to September 2010).
3. PG&E's alleged minimal compliance with some of its own line inspection report retention requirements violates other requirements (1994 to September 2010).
4. PG&E's alleged minimal compliance with some of its gas high pressure test record retention polices violates other requirements (1994 to September 2010).
5. PG&E's alleged minimal compliance with some of its record retention policies of transmission line inspections, including patrol maintenance reports, trouble reports and line logs, violates other requirements (dates ranging from September 1964 to April 2010).
6. And, the allegation that at all times between 1955 and 2010, PG&E was aware of the requirement to retain and maintain certain documents for various lengths of time but failed to fully implement the required practices (dates ranging from 1955 to September 2010).

Ms. Felts adds a record retention violation of her own (Violation 17), which relates to PG&E's alleged failure to retain Pipeline History Files (1987 to 2010).<sup>2</sup>

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<sup>1</sup> Duller/North Report at 6-34 – 6-36 and Appendix 9; Duller/North Supplement at 3-4 (Violations B.1-B.6).

<sup>2</sup> Felts Supplement at 12.

1 Chapter 2 responds to these alleged records retention violations (both the  
2 general (A.1) and more specific.<sup>3</sup> It has two parts. Part A summarizes key features  
3 of PG&E's historic records retention standards and practices. We reconstruct  
4 historic retention standards and key developments in PG&E's records storage  
5 processes. Because of the passage of time, this testimony draws mainly from  
6 historic documents describing these standards and events. This part also addresses  
7 the contention that PG&E failed to maintain Pipeline History Files.

8 In Part B, Ms. Dunn evaluates the sufficiency of CPSD's analysis that underpins  
9 the general records retention violation (A.1) and the six specific ones (B.1-B6). Ms.  
10 Dunn shows that the Duller/North Report includes numerous mistakes and  
11 unsupported assumptions that undermine the bases for its asserted violations.

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<sup>3</sup> Duller/North at 3-4 (Violations B.1-B-6); Felts Supplement at 12 (Violation 17).

1 **CHAPTER 2A**  
2 **OVERVIEW OF PG&E’S RECORDS RETENTION STANDARDS AND**  
3 **PRACTICES**

4 PG&E has had some form of records retention program in place since at least  
5 1938. As discussed below, the program has at various times included detailed  
6 retention and disposal requirements (hereafter, “standards”) and retention  
7 schedules, which were revised and refreshed to reflect regulatory changes and  
8 operating needs. The program has had some (albeit basic) audit and oversight  
9 features. It has taken into account how records were used and stored within the  
10 Company’s different organizations.

11 And, as further discussed below, PG&E’s records retention practices reflected  
12 operating realities. Looking backward, PG&E gave thought to legal, regulatory,  
13 fiscal, operational, and historic requirements of the kinds specified in the GARP  
14 Principle of Retention. Beginning in the 1950s, if not earlier, PG&E – like other large  
15 companies – was burdened with growing volumes of paper records that were costly  
16 to store and many of which were no longer useful. It expanded records storage  
17 facilities, automated indexing systems, communicated with the Commission about  
18 regulatory inconsistencies, and studied storage options and alternatives. PG&E’s  
19 records retention and disposal standards and schedules evolved in response to  
20 these records challenges in ways that took account of changing regulatory  
21 requirements and operating needs.

22 **1. Standards and Procedures**

23 At a corporate level, PG&E’s records retention standards evolved across  
24 four successive generations, as summarized in the table below:

**TABLE 2A-1  
PACIFIC GAS AND ELECTRIC COMPANY**

First Generation	December 8, 1938 Letter (Ex. 2-1) and Circular Letter Ex. #642 (Ex. 2-2)	Effective Period: 1938 – 1959
Second Generation	The Standard Practice (SP) 210.4 Series (210.4-1 through 210.4-5) (See, e.g., Ex. 2-3)	Effective Period: 1959 – 1996
Third Generation	Utility Standard Practice (USP) 4 (See, e.g., Ex. 2-4) <sup>4</sup>	Effective Period: 1996 – 2010
Fourth Generation	GOV-7001S (Ex. 2-5)	Effective Period: 2010 to present

1           These standards, and many of their revisions, were submitted to the  
2 Commission as part of the June 20, 2011 filing and appear in the Index to  
3 Chapter 2A at ranges P2-191 through P2- 233.

4           **2. PG&E Maintained Records Retention Standards and Schedules**

5           PG&E has long provided records retention guidance to its business  
6 units.<sup>5</sup> The oldest records retention document located in the course of this  
7 proceeding is a letter dated December 8, 1938, from the Company’s Vice  
8 President and General Manager to the Heads of Departments and Division  
9 Managers. (Ex. 2-1.) The letter enclosed a copy of the Federal Power  
10 Commission (FPC) “Regulations to Govern the Preservation of Records of  
11 Public Utilities and Licensees – Effective August 1, 1938,” and instructed the  
12 Departments and Divisions to maintain records in accordance with the  
13 regulations.

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<sup>4</sup> From 1996 to 1998, the first iteration of the third generation was named Corporate Standard Practice (CSP) 4. (Ex. 2-6.) Upon its scheduled revision date in 1998, the name was changed from “Corporate” to “Utility” to make it clear that the standard applied only to Pacific Gas and Electric Company, and not the holding company, PG&E Corporation, which was formed after the standard was issued.

<sup>5</sup> PG&E retains correspondence with the Commission (then the Railroad Commission of the State of California) regarding the retention and disposal of records that dates to 1915.

1 Similarly, a circular letter dated May 17, 1951 (Circular Letter Ex. #642)  
2 originated from the Company's Vice President and General Manager and  
3 was addressed to the Heads of Departments and Division Managers.<sup>6</sup> (Ex.  
4 2-2.) It enclosed a copy of the FPC "Regulations to Govern the Preservation  
5 of Records of Public Utilities and Licensees," effective August 1, 1938, with  
6 amendments to January 1, 1951. PG&E's files include a copy of 1924  
7 record retention regulations from the Commonwealth of Massachusetts,  
8 suggesting that as early as the 1920s, the Company was abreast of records  
9 retention discussions.<sup>7</sup>

10 Over time, PG&E's guidance included standards and retention  
11 schedules, or allowed for the development of such schedules.<sup>8</sup> The original  
12 SP 210.4-4 (governing records in the Divisions) included a retention  
13 schedule for the Divisions to use. (Ex. 2-8, at GTR0004114.) Later, the  
14 Company delegated responsibility to the Divisions (then referred to as  
15 "Operating Regions") to develop their own schedules, but in doing so made  
16 the Company's Supervisor of Records responsible for providing "staff  
17 assistance to all Regions in all matters pertaining to to [sic] records  
18 retention, destruction, methods and procedures, housekeeping practices,  
19 space layouts, equipment, and other areas of the records management  
20 fields." (SP 210.4-4 (eff. 6/1/86) (Ex. 2-9, at GTR0004210, GTR0004213).)  
21 Similarly, the original SP 210.4-3 (governing records in the General Office  
22 Departments) delegated to the Departments the authority to devise their  
23 own schedules. (Ex. 2-3, at GTR0004111.) When originally promulgated in  
24 1959, SP 210.4-3 provided the Departments with an exemplar schedule to  
25 use to guide their efforts, and advised Departments that they could seek the  
26 assistance of a Records Management Consultant.

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<sup>6</sup> PG&E previously provided Circular Letter Ex. #642 as part of its June 20, 2011 filing. (P2-191.)

<sup>7</sup> Commonwealth of Massachusetts Department of Public Utilities, *Regulations to Govern the Destruction of Records of Gas, Electric and Water Companies and of Municipal Lighting Plants* (Jan. 1, 1924). (Ex. 2-7.)

<sup>8</sup> As explained in Chapter 2A of PG&E's June 20, 2011 filing, historically PG&E used different names for different types of guidance documents, including: Policies, Standards, Design Standards, Guidelines, Work Procedures, Bulletins, Forms and Manuals. Beginning in July 2010, PG&E began a gradual process to convert many of these documents to a standardized naming convention, format, content, and organization. (June 20, 2011 filing at 2A-4, n.1.)

1           In a more recent era, the Company looked to the General Office  
2 Departments and the Divisions to assist in developing records retention  
3 guidance. (SP 210.4-3 (eff. 4/1/94) (Ex. 2-10).) These standard practices  
4 allowed each line of business to supplement, modify, or delete their  
5 respective retention schedules as they believed to be appropriate, in  
6 compliance with applicable regulations. (Ex. 2-10, at GTR0004258.) The  
7 resulting schedules grouped records into categories of documents (e.g.,  
8 Accounting, Human Resources, Operations and Maintenance, etc.) and  
9 provided guidance that drew from numerous regulatory sources, for  
10 example, 18 C.F.R. Parts 125 and 225, promulgated by the FPC (later  
11 known as the Federal Energy Regulatory Commission (FERC)) and  
12 Commission Resolution FA-570 (1976). (Guide to Retention of Company  
13 Documents (Apr. 6, 1994) (Ex. 2-11); Guide to Record Retention (Mar. 14,  
14 2005) (Ex. 2-12); Guide to Record Retention (May 22, 2008) (Ex. 2-13).)

15           The trend of allowing the Departments and Divisions to develop their  
16 own retention schedules continued throughout PG&E's "third generation" of  
17 records retention standards – *i.e.*, the USP 4 series. (See, e.g., Ex. 2-4.)  
18 PG&E's applicable governing standard today, GOV-7001S, similarly does  
19 not provide a schedule for record retention; rather, it is an overarching  
20 records retention policy that continues to allow each line of business to  
21 develop its own records retention schedules. (Ex. 2-5.) Several  
22 Departments, including gas, post their retention schedules on a centralized  
23 PG&E intranet site.

24           PG&E revised and refreshed the retention standards and schedules to  
25 reflect contemporaneous changes in regulatory requirements. The  
26 Company transmitted Circular Letter Ex. #642 to the Departments and  
27 Divisions in 1951 to alert them to changes made through the FPC's 1951  
28 amendments. (Ex. 2-2.) Between 1959 and 1996, the SP 210.4 series of  
29 standards was revised numerous times. Many of those revisions either  
30 refreshed the retention schedules or standards themselves, or alerted  
31 Departments and Divisions to the regulatory changes. The 1964 retention  
32 schedule that PG&E provided to its Divisions (Ex. 2-14) followed the  
33 Commission's adoption in 1962 of amendments to the FPC's records  
34 retention regulations.



1 PG&E's retention schedules also became more sophisticated over time.  
2 The 1964 retention schedule for the Divisions was basic. It consisted of an  
3 alphabetical listing of records types and associated retention periods with  
4 minimal effort to justify the retention periods or define the scope of different  
5 categories of records. (Ex. 2-14.) In contrast, by 1994, the Company's  
6 retention schedule was categorized by topic – e.g., Accounting & Corporate  
7 Records, Human Resources, Electric Supply, Gas Supply, Nuclear Power  
8 Generation, etc., and broke down records into specific sub-categories. (Ex.  
9 2-11). For example, whereas the 1964 schedule contains a single entry for  
10 "Line Inspection Reports" (Ex. 2-14, at GTR0004135), the 1994 schedule  
11 contains two entries: one for for "Electric Transmission & Distribution" and  
12 one for "Gas Transmission & Distribution" (Ex. 2-11, at GTR0004316). The  
13 same is true for "Line Patrol Reports."

14 Technological innovations influenced how PG&E stored records. As  
15 innovations like microfilm storage emerged as an alternative to paper, PG&E  
16 periodically refreshed its definition of a "record" to keep pace. For example,  
17 by 1994, SP 210.4-3 (eff. 4/1/94) defined "Records" as "all memoranda,  
18 documents, correspondence, and other materials, whether in written,  
19 microfilm, microfiche, or computer media form." (Ex. 2-10, at GTR0004258  
20 (emphasis added).) Similarly, by 1996, CSP 4 (issued 7/1/96) added "video"  
21 and "audio" to the definition. (Ex. 2-6, at GTR0004334.) By 1998, USP 4  
22 (issued 10/22/98) defined "Records" as "all memoranda, documents,  
23 correspondence, or other forms of tangible information storage (including  
24 photographs, microfilm, microfiche, video tapes, electronic media, sound  
25 recordings, etc.)." (Ex. 2-4, at GTR0004340 (emphasis added).)

### 26 **3. PG&E Corresponded with the Commission About** 27 **Inconsistencies and Uncertainties That Had Arisen in Retention** 28 **Requirements**

29 Between 1951 and 1976, the Company's retention standards and  
30 schedules placed particular emphasis on FPC/FERC records retention  
31 provisions contained in 18 C.F.R. Part 125 and Part 225. So did the  
32 Commission. During the 1950s and 1960s, the Commission periodically  
33 adopted the FPC records retention regulations and made them applicable in  
34 California without taking into account other records retention requirements in

1 the Commission's own General Orders including, by 1961, General Order  
2 112.<sup>9</sup> This dichotomy persisted until 1974, when Commission staff  
3 (specifically the Finance and Accounts Division) observed a "variance  
4 between the revised FPC regulations and the Commission's General  
5 Orders" and proposed a new Resolution (FA-554) to address the variance.

6 CPUC Resolution No. FA-554, issued in 1974, was the Commission's  
7 first attempt to reconcile the FPC (by then called FERC) records retention  
8 regulations with those that appeared in the Commission's General Orders,  
9 including GO 112-C. (Nov. 4, 1974 CPUC Letter (Ex. 2-18).) But it was not  
10 long before PG&E recognized that FA-554 had itself introduced a number of  
11 uncertainties and inconsistencies. In June 1975, PG&E wrote to the  
12 Commission, explaining in part:

13 However, in some specific instances enumerated by the  
14 resolution [*i.e.*, CPUC Res. No. FA-554], records covered  
15 by certain General Orders were assigned retention  
16 periods that would apply in lieu of the otherwise  
17 applicable FPC rule. Recognizing that this formulation of  
18 retention regulation could cause uncertainty, PGandE set  
19 about a study to determine exactly what retention periods  
20 should be applied to all Company records to assure  
21 compliance with the CPUC and FPC regulations to which  
22 it is subject.

23 The results of this study are disturbing. A number of  
24 uncertainties and inconsistencies appear which cannot  
25 be resolved by the general provisions of Resolution No.  
26 FA-554. Without attempting to be exhaustive, a number  
27 of examples have been collected, and are outlined in the  
28 two-page Appendix B attached hereto. On these and  
29 similar record retention questions PG&E is in need of  
30 further guidance.

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<sup>9</sup> See CPUC Res. No. 157, issued July 22, 1952 (Ex. 2-15); CPUC Res. No. 216, issued January 16, 1956 (Ex. 2-16); and CPUC Res. No. 387 issued October 22, 1963 (Ex. 2-17).

1 (Jun. 16, 1975 PG&E Letter (Ex. 2-19).) Among the examples that PG&E  
2 collected and submitted to the Commission was one relating to FA-554's  
3 treatment of certain GO 112-C records. PG&E wrote in Appendix B to its  
4 June 1975 letter:

5 PUC GENERAL ORDER 112C

6 PUC Resolution FA-554 requires a retention period  
7 of 40 years for annual reports. All record retention  
8 requirements listed in this general order are for the life of  
9 the pipeline. Where does the 40 year retention apply?

10 (Ex. 2-19.) In the wake of this letter, representatives of the Commission and  
11 PG&E met to discuss the ambiguities in FA-554. The Commission asked  
12 PG&E to draft a proposed new resolution providing retention periods for  
13 specific record types of concern to the Commission. PG&E did so, and  
14 circulated the proposed resolution to two other utilities (Southern California  
15 Edison and San Diego Gas & Electric) for feedback. Both utilities endorsed  
16 PG&E's proposed resolution.<sup>10</sup> Subsequently, in August of 1976, the  
17 Commission superseded FA-554 with a new Resolution, No. FA-570, which  
18 was similar (albeit not identical) to PG&E's proposed resolution. (Ex. 2-21.)  
19 FA-570 provided new, comprehensive retention periods for General Order  
20 records, including GO 112-C records.

21 FA-570 marked the first time the Commission addressed  
22 comprehensively the retention of records of the kind required to be  
23 maintained by General Orders, including the then-applicable GO 112-C.  
24 The Commission explained it had made a misstep in 1974 that it now sought  
25 to correct:

26 By Resolution No. FA-554, this Commission adopted  
27 certain retention requirements which supplemented the  
28 Federal Power Commission requirements. The  
29 Commission has reconsidered the matter of adopting the  
30 Federal Power Commission's regulations and based on  
31 the Staff's recommendation concludes that Resolution  
32 No. FA-554 should be modified and that preservation of

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<sup>10</sup> Dec. 5, 1975 letter from PG&E to the Commission, and attachments thereto. (Ex. 2-20.)

1 records by gas and electric utilities under the jurisdiction  
2 of this Commission should be governed by the  
3 regulations of the Federal Power Commission except as  
4 modified herein.

5 .....  
6 IT IS ORDERED that the revised regulations for the  
7 preservation of records made effective by Federal Power  
8 Commission Order No. 450 [*i.e.*, the 1972 amendments  
9 to 18 C.F.R. Part 225], except as modified by the specific  
10 retention periods for the records contained in this  
11 Resolution, are adopted by the Commission for all gas  
12 and electric companies operating in this State under its  
13 jurisdiction. Records shall be retained for the periods  
14 required by the FPC Order or this Resolution, whichever  
15 is the longer period, and may be disposed of after the  
16 expiration of such retention periods.

17 (Ex. 2-21, at GTR0002273 (emphasis added).)

18 Within months of FA-570's adoption, in November 1976, PG&E revised  
19 its records retention standards for its General Office Departments and  
20 Divisions – SP 210.4-3 and SP 210.4-4, respectively – to reflect the  
21 Commission's adoption of FA-570. (Ex. 2-22, at GTR0004158; Ex. 2-23, at  
22 GTR0004166.) FA-570 may have been the last instance in which the  
23 Commission comprehensively addressed records retention, although  
24 regulatory activity in this area continues. As recently as October 2007, the  
25 National Association of Regulatory Utility Commissioners promulgated  
26 model records retention regulations to be used as guidelines by the states in  
27 developing regulations to govern the preservation of records of electric, gas  
28 and water utilities.<sup>11</sup>

29 This discussion illustrates several points that the Duller/North Report  
30 fails to address. Historic variances may arise between records retention  
31 requirements contained in FPC/FERC regulations and the Commission's

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<sup>11</sup> National Association of Regulatory Utility Commissioners, *Regulations to Govern the Preservation of Records of Electronic, Gas and Water Utilities* (Rev. Oct. 2007). (Ex. 2-24.)

1 General Orders, including GO 112-C. It was not until the mid-1970s that the  
2 Commission attempted to address those variances. PG&E had a sufficiently  
3 vigorous records retention program during this era to undertake a study of  
4 the different regulatory requirements and explain to the Commission how  
5 those requirements had created inconsistencies and uncertainties. PG&E  
6 communicated to the Commission in 1975 its clear understanding that GO  
7 112-C records were generally “life-of-the-facility” records. PG&E quickly  
8 refreshed its retention standards in response to regulatory developments  
9 (e.g., the adoption of FA-570). The Commission devoted some attention to  
10 the subject of records retention in the 1950s, 1960s and 1970s, but does not  
11 appear to have considered records retention for utilities since that era.

#### 12 **4. The Corporate Retention Standards Included Audit and Oversight** 13 **Features.**

14 PG&E agrees that it needs to incorporate better and stronger audit and  
15 oversight features into its records retention program. However, that does  
16 not mean, as the Duller/North Report suggests, that throughout the past  
17 PG&E’s retention program lacked audit and oversight features.

18 To ensure compliance with the 1951 amendments to the FPC  
19 regulations, Circular Letter Ex. #642 designated the General Office  
20 Department Heads and Division Managers to supervise the preservation,  
21 indexing, and destruction of records. (Ex. 2-2.) It required each Division  
22 and General Office Department to index its records according to a  
23 classification schedule set forth in the letter. And, it required those same  
24 Divisions and General Office Departments to send a copy of their index to  
25 the office of the “General Auditor” to be maintained as a master index. (Ex.  
26 2-2, at GTR0004110.)

27 As new generations of standards superseded older ones, audit and  
28 oversight features changed. Throughout its life cycle, the SP 210.4-4 series  
29 of standards included an audit provision which provided that the Division  
30 Records Management Advisor (later Regional Records Management  
31 Advisor) should check periodically to see that records were destroyed in  
32 accordance with the retention periods set forth in the Records Schedule.  
33 (See, e.g., Ex. 2-23, at GTR0004167; Ex. 2-9, at GTR0004213.) Beginning  
34 no later than the late 1980s, changes in retention standards suggest

1 increased oversight by the Corporate Secretary and the Law Department.  
2 For example, in this era, the Corporate Secretary assumed overall  
3 responsibility for issuing, updating, and monitoring compliance with the  
4 retention standards. (Corporate Records (Ex. 2-25), at GTR0004228.)  
5 Retention standard changes also reflect that the General Counsel assumed  
6 a role in providing legal guidance regarding records retention legal  
7 requirements. (Ex. 2-25, at GTR0004229.)

8 The Duller/North Report's further suggestion that PG&E has not audited  
9 its records retention program is inaccurate. As early as April 1950, the  
10 Company decided to have "traveling auditors" review the condition of  
11 records in the Divisions to determine if responsible parties had been  
12 complying with the FPC's 1938 records retention regulations.<sup>12</sup>

13 Moreover, the Commission staff has regularly audited and inspected the  
14 gas safety records maintained in PG&E's Divisions. In describing its Natural  
15 Gas Safety Program, the Utilities Safety Reliability Branch (USRB)  
16 emphasizes its review of a gas utility's operation and maintenance records  
17 as part of its gas audit and oversight activities:

18 The USRB enforces Federal Pipeline Safety Regulations  
19 through its natural gas safety program. The USRB  
20 administers its natural gas safety program by auditing the  
21 facilities of investor-owned natural gas utilities in  
22 California for compliance with the applicable codes. *The*  
23 *audit consists of reviewing operation and maintenance*  
24 *records, evaluating emergency procedures, and*  
25 *performing random field inspections of the natural gas*  
26 *facilities.* Investor-owned utilities are generally audited  
27 once every two years; however, the utility may be audited  
28 more frequently depending on the results of the audit.

29 (CPUC Website, Natural Gas Safety Program, [http://www.cpuc.ca.gov/PUC/](http://www.cpuc.ca.gov/PUC/aboutus/Divisions/Consumer+Protection/Utilities+Safety+Branch/Natural+Gas+Safety/index.htm)  
30 [aboutus/Divisions/Consumer+Protection/Utilities+Safety+Branch/Natural+Ga](http://www.cpuc.ca.gov/PUC/aboutus/Divisions/Consumer+Protection/Utilities+Safety+Branch/Natural+Gas+Safety/index.htm)  
31 [s+Safety/index.htm](http://www.cpuc.ca.gov/PUC/aboutus/Divisions/Consumer+Protection/Utilities+Safety+Branch/Natural+Gas+Safety/index.htm) (last visited June 20, 2012) (emphasis added) (Ex. 2-  
32 27).) The description of what the Commission staff audits ("reviewing

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<sup>12</sup> PG&E letter dated April 4, 1950 to the Chairman of the Coordinating Committee. (Ex. 2-26.)

1 operational and maintenance records, evaluating emergency procedures  
2 and performing random field inspections of the natural gas facilities”)  
3 captures the staff’s historic audit emphasis. Historically, the Commission  
4 staff’s audits emphasized a review of records maintained at PG&E facilities,  
5 usually Division and District offices, that demonstrate that a specified gas  
6 safety compliance action, e.g., a leak survey or a line patrol, has occurred.  
7 If for the past almost 50 years PG&E’s Divisions and Districts have been  
8 failing to retain maintenance and operations records of the kind discussed  
9 by Dr. Duller and Ms. North, the Commission staff would have brought those  
10 failings to PG&E’s attention long before now.

11 As PG&E explained in a data request response, it performed an internal  
12 audit of electronic data management practices in 2008. (PG&E’s Response  
13 to Records OII Data Request 25 Q 8(b) (Ex. 2-28).) The audit identified that  
14 although the then-existing records retention and disposal standard (USP 4)  
15 defined officer-level accountability for implementing data retention and  
16 disposal procedures, the Corporate Secretary lacked sufficient controls to  
17 ensure compliance. (Ex. 2-28.) The audit further found that many “business  
18 leaders, system owners, and Compliance Champions” do not have any data  
19 retention procedures in place, do not monitor compliance with their data  
20 retention policies or periodically confirm that the specified retention periods  
21 are still valid, and have experienced issues concerning obsolete data in key  
22 systems they use. (Ex. 2-28.) The audit recognized that, by April 15, 2009,  
23 the Corporate Secretary would establish an action plan to address these  
24 issues and that, by September 30, 2009, it would begin an “annual  
25 communications campaign” to inform officers of the requirements in USP 4  
26 and begin annual surveys of officers to obtain written confirmations from  
27 them regarding compliance with USP 4 as well as to track plans for resolving  
28 any shortcomings they identify. (Ex. 2-28.) Consequently, the Corporate  
29 Secretary’s office began an annual “Compliance Certification” process,  
30 whereby every September, the Corporate Secretary’s office would send a  
31 copy of the operative record retention standard to each line of business.  
32 (PG&E’s Response to Records OII Data Request 23 Q 35 (Ex. 2-29).)  
33 Each line of business would then respond by either acknowledging that it

1 was in compliance, or that it was not in compliance but that it would develop  
2 a plan of action for becoming compliant.<sup>13</sup>

3 In response to the September 2009 compliance certification email from  
4 the Corporate Secretary's office, Transmission & Distribution (which at the  
5 time consisted of both gas and electric) determined that it should revise its  
6 guidance on record retention under USP 4 (the operative standard at the  
7 time). The result was the revised "Records Retention and Disposal  
8 Guidance for Transmission & Distribution Systems" which became effective  
9 in April 2010 (Ex. 2-33).

## 10 **5. The Corporate Standards Included Process-Centric Elements.**

11 PG&E's records retention standards historically reflected the way the  
12 business actually worked. First, the SP 210.4 series of standards reflected  
13 the business' organizational structure. SP 210.4-1 addressed accounting  
14 records; SP 210.4-2 addressed records of company subsidiaries; SP 210.4-  
15 3 addressed records of General Office Departments; and SP 210.4-4  
16 addressed records of Divisions. This separation of standards by function,  
17 particularly the separation between SP 210.4-3 and SP 210.4-4, reflected  
18 the historic reality of how much of the day-to-day maintenance and  
19 operations work of the Company was done regionally in Divisions and  
20 Districts.

21 Second, the standards reflected how records moved through the  
22 organization. In the case of PG&E's Departments, records were historically  
23 maintained in the Company's General Office until they were no longer  
24 frequently consulted. At that point, the Departments had the ability to  
25 centrally archive older records at the Bayshore Records Center and recall  
26 them for use, as necessary. Dating almost from the time that the Bayshore  
27 Records Center was constructed, SP 210.4-3 captured this process. The  
28 first revision to SP 210.4-3, effective March 1, 1961, came shortly after the

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**13** The CP&S's consultants misunderstand the compliance certification process, asserting that, despite PG&E's statement that Record Retention and Disposal Standard GOV-7001S is to be issued annually in September, the version presented to the Commission in October 2011 was dated October 2010. A new version of the standard is not issued every year; rather, the current standard is re-circulated every year in connection with the compliance process. (Ex. 2-29.) The 2010 version of GOV-7001S is still the current version. (Ex. 2-5.)



1 newly constructed Bayshore Records Center (see discussion below) had  
2 opened in South San Francisco near Martin Station. (Ex. 2-30.) The 1961  
3 revisions included instructions to the Departments for transferring records to  
4 the Records Center, procedures for requesting records back once they had  
5 been transferred, and provisions ensuring that the Departments would retain  
6 the final word before the Records Center disposed of any record.<sup>14</sup>

7 In contrast, early versions of SP 210.4-4 made no provision for Division  
8 records to be archived centrally at the General Office. (Ex. 2-8; Ex. 2-23).  
9 This too reflected the operating reality that Divisions historically functioned  
10 with a high-degree of autonomy and took responsibility for their own facilities  
11 and records, many of which were used infrequently, but when used needed  
12 to be readily available locally. Instead, SP 210.4-4 provided that the records  
13 would be stored locally, but that the Supervisor of Records would be  
14 responsible for providing staff assistance to all Divisions in matters  
15 pertaining to records retention, destruction, methods and procedures,  
16 housekeeping practices, space layouts, equipment, and other areas of the  
17 records management field. (Ex. 2-23, at GTR0004167.) Eventually, SP  
18 210.4-4 provided that information on transferring records to records storage  
19 facilities could be obtained by contacting the Supervisor of Records. (Ex. 2-  
20 31, at GTR0004244.)

## 21 **6. PG&E Corporate Records Retention Schedules Addressed** 22 **Contemporaneous Legal Requirements**

23 CPSD's consultants assert that PG&E misscheduled different kinds of  
24 documents in violation of ASME § B31.8; GO 112, 112-A and 112-B; and 49  
25 C.F.R. Part 192.709. In several instances their allegations merely highlight  
26 the difficulty in trying to find fault with policies and schedules issued and  
27 maintained so long ago.

28 Dr. Duller and Ms. North are critical of the retention periods for "Line  
29 Patrol Reports" listed in PG&E's 1994, 2005, and 2008 retention schedules.  
30 Yet each of those schedules provide that line patrol reports shall be retained  
31 for the life of the facility for numbered gas transmission lines and three years

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<sup>14</sup> The Office of Corporate Secretary would later, in 1962, assume responsibility for administering the Records Center.

1 for all other lines. (Ex. 2-11, at GTR0004316; Ex. 2-12, at GTR0004420; Ex.  
2 2-13, at GTR0004479.) The CPSD acknowledged its mistake in discovery  
3 responses served after the Duller/North Report was issued: “CPSD notes  
4 that a violation would exist with the requirement to keep any non-numbered  
5 Gas Transmission Line for only three years. CPSD would make this addition  
6 as errata to Appendix 9 of Dr. Duller’s and Ms. North’s report and Appendix  
7 8 of Ms. Felts’ report. (This requirement is to also keep numbered gas  
8 transmission lines for the life of the facility.)” (CPSD’s Response to Records  
9 OII Data Request 8-Q4 (Ex. 2-32).)

10 Dr. Duller and Ms. North are also critical of PG&E’s 1994, 2005, and  
11 2008 retention schedules for requiring that “Line Inspection Reports” be  
12 retained for only three years, in violation of the ASME standards and 49  
13 C.F.R. Part 192. It would seem, however, that PG&E’s mistake (if  
14 attempting to take account of a federal regulation in a retention schedule  
15 can be considered a mistake) was to schedule a category of records  
16 described in the FERC records retention regulations. The 1994, 2005, and  
17 2008 retention schedules addressing “Line Inspection Reports” each  
18 reference “FERC 23D.” That is a reference to Part 225.3, Subsection (d)  
19 (“Records of general inspection and operating tests”) of Section 23  
20 (“Transmission and distribution—Gas”). It too specifies a three-year  
21 retention period. (Ex. 2-11, at GTR0004316; Ex. 2-12, at GTR0004420; Ex.  
22 2-13, at GTR0004479.)

23 Dr. Duller and Ms. North also criticize PG&E’s 2010 schedule for  
24 mandating retention of “Leak Survey Maps” for only nine years, when Part  
25 192.709(c) has required since 1996 that such records be kept for five years  
26 or until the next leak survey, whichever is greater. (Ex. 2-33, at  
27 GTR0002478.) Even assuming that “Leak Survey Maps” qualify as a record  
28 of a “patrol, survey, inspection, and test” under Part 192.709(c), Dr. Duller  
29 and Ms. North have to stack several layers of assumptions on top of one  
30 another to conclude that a nine-year retention period is insufficient to meet a  
31 five-year (or until the next leak survey) retention period. PG&E performs  
32 leak surveys of its transmission lines annually for Class 1 and 2 lines and  
33 semi-annually for Class 3 and 4 lines. (UO Standard S4110: Leak Survey  
34 and Repair of Gas Transmission and Distribution Facilities – Attachment 1

1 (Ex. 2-34), at GTR0118239.) And, the Commission historically has regularly  
2 performed audits of Division and District leak records, including audits of two  
3 Districts per year.

4 In any event, PG&E's retention schedules from 1994, 2005, 2008, and  
5 2010, all include entries for "Leak Survey Inspections" and/or "Leak Survey  
6 Logs" with mandated retention periods of life of the facility or in some cases  
7 longer. (Ex. 2-11, at GTR0004316; Ex. 2-12, at GTR0004420; Ex. 2-13, at  
8 GTR0004479; and Ex. 2-33, at GTR0002478.) With respect to those  
9 records, the retention schedules complied with – and after 1996 exceeded –  
10 Part 192.709(c), which provides that a record of each patrol, survey,  
11 inspection, and test must be retained for the life of the facility (from 1970 to  
12 1996) or for at least five years or until the next survey or inspection (but not  
13 map) is completed, whichever is longer (from 1996 to the present).

14 The Duller/North Report attempts to read PG&E's historic records  
15 retention schedules in a vacuum and without any reference to context.  
16 There is no acknowledgement in the report that the CPSD was regularly  
17 auditing gas pipeline safety records maintained in PG&E's Divisions and  
18 Districts during the period of the alleged violations. Nor is there any  
19 acknowledgement that the Commission's records retention resolutions were,  
20 at least prior to 1976, focused on the FPC regulations. In 1964, the  
21 Commission had itself just recently adopted the FPC's Part 225 retention  
22 schedules through CPUC Resolution No. 387 issued on October 22, 1963  
23 (Ex. 2-17), but did so without referencing General Order 112 or any other  
24 General Order. As discussed, the Commission did not undertake the effort  
25 of harmonizing the FPC's records regulations and the Commission's  
26 General Order retention provisions until the mid-1970s.

27 The above examples illustrate why PG&E's historic records retention  
28 schedules need to be read contextually and with the then-applicable  
29 retention requirements in mind. One of the hazards of alleging a records  
30 retention schedule violation over a span of more than 55 years is that it is  
31 difficult to resolve ambiguities by reference only to the decades-old retention  
32 schedules. The task becomes even more difficult when little account is  
33 taken of the FPC and FERC regulations, and when no reference is made to  
34 an environment in which those records were audited year after year.

1           **a. Records Transmittal, Storage and Destruction**

2           Reading PG&E's retention schedules in isolation, CPSD's  
3           consultants formed the view that PG&E historically treated the subject of  
4           records retention largely as a cost-saving exercise.<sup>15</sup> Again, their  
5           analysis lacks historical context.

6           In 1958, PG&E's management approved the construction of the  
7           original Bayshore Records Center; construction began in 1959 and was  
8           completed in 1961. (Pacific Gas and Electric Company Records Center  
9           History (Ex. 2-35).) As we have seen, beginning in 1961, SP 210.4-3  
10          was revised to create a procedure for General Office Departments to  
11          transfer older records to the Records Center. (Ex. 2-30, at  
12          GTR0004117.) Records previously stored at other off-site locations  
13          were also consolidated at the Records Center. Records previously  
14          stored at 530 Bush Street were transferred to the Records Center in  
15          1965. (Ex. 2-35.) Plant accounting records stored in Sacramento were  
16          transferred there in 1967. (Ex. 2-35.) Records from 345 Mission Street  
17          were transferred there in 1970. (Ex. 2-35.)

18          Within a few years of when it opened, the Records Center struggled  
19          to make room for the growing volume of paper records. The original  
20          Bayshore Records Center reached capacity in 1967. (Ex. 2-35.) A  
21          1967 expansion of the Records Center doubled its capacity, but by  
22          1971, the expanded Bayshore facility had again reached capacity. (Ex.  
23          2-35.) The Company used an additional facility (known as the Sugar  
24          House) at the Potrero Power Plant for records storage and later in the  
25          mid-1970s began using the 33rd floor at the Company's headquarters to  
26          store records. (Ex. 2-35.) Despite these efforts the records storage  
27          problem grew. The Company undertook at least two studies in this era  
28          to determine solutions, including the feasibility of microfilming increasing  
29          numbers of records.<sup>16</sup> (Evaluation of Feasibility: Microfilming Vital  
30          Records Housed in the Records Center (Ex. 2-36).) In 1983, the

---

<sup>15</sup> Duller/North Report at 6-33.

<sup>16</sup> A study of the records storage problem done in the mid-1970s indicated that in 1974 the Records Center took in 6,589 cubic feet of new records but only disposed of 2,965 feet. (Ex. 2-36.)

1 Company completed a further expansion of the existing Records Center,  
2 known as the Western Addition of the Records Center, to accommodate  
3 the growth in the volume of records being archived.<sup>17</sup> (Ex. 2-35.) At  
4 about this same time, PG&E developed a computer system that allowed  
5 for the tracking of records when they entered, left or were transferred  
6 among PG&E storage facilities. (P2-1469.) The system also allowed for  
7 the Records Center to generate periodic reports, a task that formerly  
8 took numerous hours to complete. That system was transferred to a PC  
9 desk top system in 1985. (Ex. 2-35.)

10 Today, the Bayshore Records Center still functions as a repository,  
11 but in a more limited sense. In 2011, as part of the initial phase of the  
12 MAOP Validation project, numerous records, including gas transmission  
13 records, were transferred out of the facility. PG&E's Emeryville facility  
14 now serves as a central repository for many (but not all) gas  
15 transmission pipeline construction and testing records.

16 **b. The Retention of Pipeline History Files**

17 In her supplemental report, Ms. Felts asserts that PG&E's inability to  
18 locate "Pipeline History Files" violates Public Utilities Code Section 451,  
19 ASME § B31.8, and PG&E's internal guidance requiring retention of  
20 engineering records. She refers to Sections 4.1.1 and 4.1.2 of the Felts  
21 Report for supporting analysis and contends that the violations arose in  
22 1987 and continued through 2010. The Duller/North Report also  
23 criticizes PG&E for not retaining Pipeline History Files, suggesting that  
24 the failure to account for the files today is evidence of the "subjective"  
25 way in which PG&E implemented its retention standards.<sup>18</sup>

26 The Pipeline History Files that the CPSD's consultants describe  
27 would have been created pursuant to former Standard Practice 463.7.  
28 (PG&E's Response to Records OII Data Request 34 Q 1 (Ex. 2-37).)  
29 SP 463.7 addressed the subject: "Pipeline History Files, Establishing  
30 and Maintaining." (Ex. 2-38.) The standard was meant to provide "a

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<sup>17</sup> So great were the records storage problems during this era, that the Company entertained the idea of lobbying to change the regulations for storage mandated by FERC and the Commission.

<sup>18</sup> Duller/North Report at 6-37 and 6-47.

1 current and uniform history record of pipelines (and mains) that have a  
2 Maximum Allowable Operating Pressure (MAOP) resulting in a hoop  
3 stress equal to or greater than 20% of the Specified Minimum Yield  
4 Strength (SMYS).” (Ex. 2-38.)

5 In its original iteration, SP 463.7 gave responsibility for establishing  
6 and maintaining Pipeline History Files to supervisors out in Division  
7 offices and to the Pipeline Operations Department, a predecessor  
8 organizational structure to PG&E’s current gas transmission Districts.  
9 The Supplement to SP 463.7 described the data that the history file  
10 should include. (Ex. 2-38.)

11 Available versions of SP 463.7 suggest that the standard imposed  
12 two reporting requirements on each responsible Division or Department.  
13 The first required the Division or Department to submit to the Manager  
14 of Gas System Design a completed initial copy of the 8-letter size form  
15 entitled “Pipeline Survey” and to annually submit updated “Pipeline  
16 Survey” Sheets. (Ex. 2-38.) It imposed the further obligation on  
17 Divisions to submit annually, before February 1, to the Manager of Gas  
18 Distribution, a completed copy of Form 75-352 “Annual Report for  
19 Pipeline and Mains Operating At or Over 20% SMYS” for each pipeline  
20 and main covered by the standard. The form (Exhibit A to SP 463.7) is  
21 identified as a GO 112-B form, indicating that it was an annual report  
22 then required under GO 112-B.<sup>19</sup> (Ex. 2-38.) As for recordkeeping, SP  
23 463.7 required that “[h]istory records for numbered transmission lines  
24 shall be filed by line number, with all pertinent inclusions of data shown  
25 in paragraphs 5 and 6, indexed for ready reference, and cross-

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**19** General Order 112-B imposed annual reporting requirements relating to the surveillance of pipelines and mains and the operation and maintenance studies for pipelines operating above 20% SMYS. (GO 112-B, sections 401.5 and 401.6 (eff. 1967).) SP 463.7 suggests that PG&E compiled the Form 75-352’s submitted by the Divisions and Pipeline Operations Department and submitted them to the Commission as part of its annual report. (Pacific Gas and Electric Company Pipeline Surveillance Procedures, Operating and Maintenance Studies, and Location Class Changes (Mar. 1969).) The Commission’s reporting requirements relating to the surveillance of pipelines and mains (Section 401.5) were short-lived. They were removed in 1971 when the Commission adopted GO 112-C. The requirement to file reports summarizing operating and maintenance studies (Section 401.6; later Section 141.4) lasted longer. It was retained through GO 112-D, before being removed with the adoption of GO 112-E (eff. 1995).

1 referenced to other permanent files, such as GM or Work Order files.”  
2 (Ex. 2-38.)

3 Former SP 463.7 appears to have taken effect in 1969 and been  
4 operative until no later than October 1987. A letter dated October 9,  
5 1987 from the Organization Planning and Development Department to  
6 Officers and General Office Department Heads lists SP 463.7 among  
7 several Standard Practices that “[w]e have been asked to cancel.” (Ex.  
8 2-39.) A May 3, 1984 memo from the San Joaquin Gas Superintendent  
9 to San Joaquin Division District Managers suggests that SP 463.7  
10 remained in effect as of at least that date. (Ex. 2-40.)

11 In the words of Dr. Duller and Ms. North, the Pipeline History Files  
12 were “really a secondary source of information,” and in this regard they  
13 appear to be right.<sup>20</sup> The “Pipeline Survey Sheets” – a main output of  
14 the SP 463.7 standard – contained a summary of data about the  
15 pipeline reduced to a single sheet of paper. SP 463.7 also required the  
16 Divisions to keep in the Pipeline History Files selected documents  
17 relating to the numbered transmission lines, but these documents were  
18 themselves copies of underlying documents, as SP 463.7 makes clear.  
19 (Ex. 2-38.) SP 463.7 speaks in terms of those document files as being  
20 cross-referenced to “other permanent files, such as GM or Work Order  
21 Files.” (Ex. 2-38.) This is a reference to job files of the kind that PG&E  
22 uses today as part of the MAOP records verification and MAOP  
23 validation effort.

24 It is true, as Ms. Felts says, that SP 463.7 required that the Pipeline  
25 History Files be maintained for the “life of the facility,” but that  
26 requirement arose by operation of SP 463.7, not by operation of law.  
27 When SP 463.7 was rescinded no later than October 1987, its “life of the  
28 facility” requirement was rescinded along with it. Once SP 463.7 was  
29 rescinded, the Divisions, Departments, and Manager of Gas System  
30 Design would have been holding onto secondary sources of information  
31 and copies of original documents found elsewhere, such as in job files.

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<sup>20</sup> In discovery, the CPSD similarly acknowledged that the Pipeline History Files were “derived from a variety of primary sources such as the job folders[.]” (CPSD’s Response to Records OII Data Request 8 Q 1.)

1 At that point, SP 463.7 documents would have been subject to disposal  
2 under the Company's records retention standards.<sup>21</sup>

3 The Pipeline Survey Sheets – a key output of SP 463.7 – were  
4 retained even after SP 463.7 was rescinded. An example of a Pipeline  
5 Survey Sheet appears below. It contains a plan view scale map  
6 showing the location of the pipeline, accompanied by tabular information  
7 such as the following:

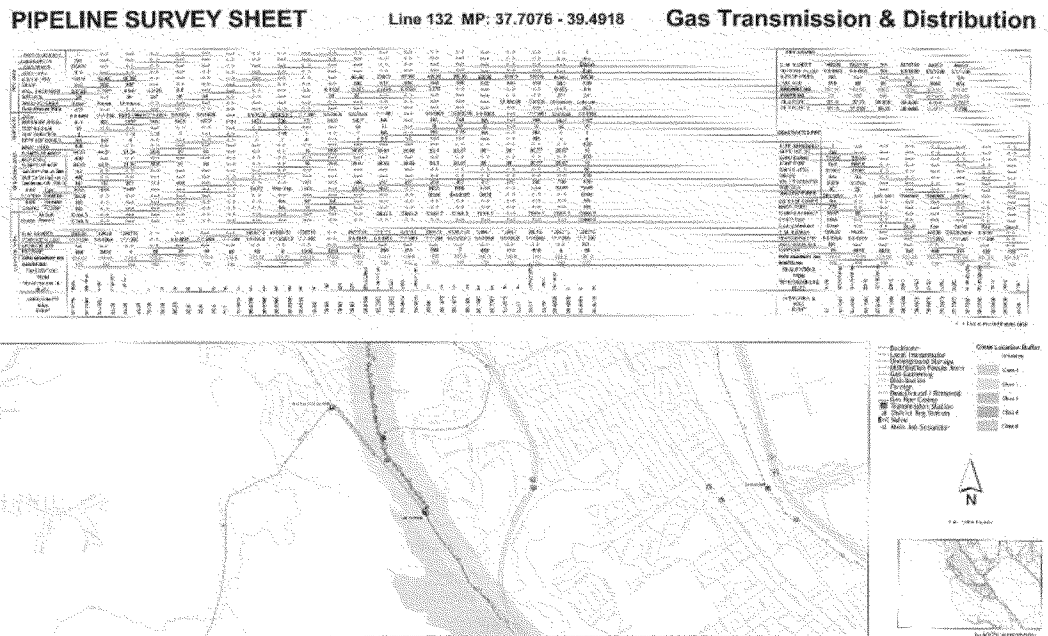
- 8 • pipe data (joint efficiency, girth welds, long seams, joint type, SMYS,  
9 grade, wall thickness, size – OD, manufacture, design pressure);
- 10 • test data (data, pressure, test medium, test duration, depth of  
11 cover);
- 12 • operating data (MAOP, percent SMYS at MAOP, MOP, percent  
13 SMYS at MOP, pipe coating type and condition);
- 14 • pipe casing diameter and footage; and
- 15 • location data (class as built and present, GM number, year installed,  
16 footage, pipe segment number, route number, stationing from  
17 transmission line plats, approximate point).

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**21** For example, SP 210.4-3 (eff. 4/1/94) addresses duplicate records in the following terms: "Duplicate copies of records should be destroyed as soon as they have served their intended purpose and proper retention of the original document has been verified." (Ex. 2-10, at GTR0004265.)



**FIGURE 2A-1  
PACIFIC GAS AND ELECTRIC COMPANY  
PIPELINE SURVEY SHEET**



1                   The Pipeline Survey Sheets would later be used in the 1990s to  
2                   populate the initial gas transmission GIS.

3                   In retrospect, the Company wishes it had retained the Pipeline  
4                   History Files. Those files would have likely enhanced the Company's  
5                   ability to respond to the NTSB's January 3, 2011 recommendations and  
6                   the Commission's directives to aggressively and diligently search for  
7                   design basis records needed to confirm MAOP. But in asserting that  
8                   PG&E violated the law by not retaining copies of records maintained  
9                   under a now-abolished standard, the CPSD's consultants confuse the  
10                  desirable with the mandatory.

11                  **c. The Retention of Patrol, Survey, Inspection, and Test Records**

12                  Many of the Duller/North records retention violations share a  
13                  common thread: they assert that PG&E's corporate records retention  
14                  standards and schedules did not prescribe sufficient retention periods  
15                  for the kinds of line patrol, survey, inspection and test records formerly  
16                  required to be maintained by GO 112 (incorporating ASA §§ B31.8 and  
17                  851.5) and 49 C.F.R. 192.709.<sup>22</sup>

<sup>22</sup> Duller/North Supplement at Section II.B.1–II.B.5.

1           Missing from the Duller/North analysis, however, is any substantive  
2 discussion of the utility standards that actually govern how PG&E’s gas  
3 organization retained records in connection with these activities. In its  
4 June 20, 2011 filing, PG&E provided an attachment that detailed  
5 records-related utility standards, work procedures and bulletins.  
6 Included in that attachment were standard practices, bulletins, and  
7 forms governing activities of the kind covered by Section 851.5 and Part  
8 192.709. (See, e.g., SP 460.2-1 (Patrolling Pipelines and Mains) (P2-  
9 1240); SP 460.21-4 (Routine Inspection for Gas Leakage) (P2-1149);  
10 SP 460.2-2 (Physical Inspection: Pipelines, Mains, and Services) (P2-  
11 1325).) Those standard practices, bulletins, and forms included  
12 provisions governing the creation and retention of records. (See  
13 generally P2-1149 to P2-1244.) It was these “Gas Standards” – more  
14 so than corporate retention schedules – that drove the records decisions  
15 about pipeline records made by personnel in PG&E’s gas organization.

16           As Maura Dunn explains in greater detail in her Expert Report, the  
17 omission is significant. Included within PG&E’s standard practices were  
18 requirements that respond to many of the Duller/North Report’s specific  
19 allegations.  
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**CHAPTER 2B**  
**PG&E'S RECORDS RETENTION POLICIES MET APPLICABLE**  
**REGULATORY RECORDKEEPING REQUIREMENTS**

Maura Dunn, a records management expert, responds to assertions contained in the Duller/North Report about PG&E's records retention policies that form the basis for the alleged violations that appear in Section II.B of the Duller/North Supplement. Her response is contained in the Expert Report of Maura L. Dunn, MLS, CRM PMP, which is incorporated here by reference.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 3**  
**PG&E'S USE OF RECORDS**

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1 **CHAPTER 3**  
2 **PG&E'S USE OF RECORDS**

3 This chapter addresses PG&E's use of gas transmission pipeline records. It  
4 primarily responds to Ms. Felts' allegations that records are missing, incomplete  
5 or inaccessible, and that these shortcomings impacted PG&E's gas pipeline  
6 safety efforts, and particularly its Integrity Management Program.<sup>1</sup> This chapter  
7 addresses the following violations asserted in the Felts Supplement:

- 8 16. Job Files Missing and Disorganized  
9 18. Design and Pressure Test Records Missing  
10 19. Weld Maps and Weld Inspection Reports Missing or Incomplete  
11 20. Operating Pressure Records Missing, Incomplete or Inaccessible  
12 21. Pre-1970 Leak Records Missing, Incomplete or Inaccessible  
13 22. Post-1970 Leak Records Missing, Incomplete or Inaccessible  
14 23. Records to Track Salvaged and Reused Pipe Missing  
15 26. 1988 Weld Failure – No Report  
16 27. The 1963 Weld Failure – No Report

17 This chapter also addresses the three violations alleged in Part II.C of the  
18 Duller/North Report. Those violations relate to PG&E's Gas Pipeline  
19 Replacement Program (C.1), the maintenance of records that relate to risks  
20 associated with earthquakes (C.2), and the collection of data relating to historic  
21 gas pipeline leaks (C.3).

22 This chapter has seven parts. In Part A, John S. Zurcher addresses how  
23 pipeline records have been used in the gas pipeline industry, particularly with the  
24 advent of risk assessment and integrity management processes.

25 Part B provides a brief historical overview of the development of PG&E's  
26 gas transmission system. This overview initially appeared in Chapter 1A of  
27 PG&E's June 20, 2011 submission.

28 Part C addresses PG&E's historic use of engineering, construction,  
29 operations, and maintenance records, including allegations about PG&E's use  
30 and tracking of reconditioned pipe, its numbering and indexing of job files, and  
31 its handling of material failure reports.

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<sup>1</sup> Felts Report at 26-47.



1           Part D addresses two related topics: records relating to PG&E's ground  
2 movement program, and PG&E's decades old Gas Pipeline  
3 Replacement Program.

4           Part E addresses specific allegations contained in the Felts Report about  
5 PG&E's Integrity Management program.

6           Part F specifically addresses how leak records have historically been  
7 maintained and used.

8           Part G responds to allegations in the Felts Report concerning PG&E's GIS.

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**CHAPTER 3A**  
**EXPERT TESTIMONY OF JOHN ZURCHER REGARDING**  
**HISTORICAL RECORDKEEPING PRACTICES IN THE**  
**NATURAL GAS PIPELINE INDUSTRY**

5

**1. QUALIFICATIONS AND MATERIALS REVIEWED**

6

**a. Qualifications**

7 I am a gas pipeline consultant with extensive experience in pipeline  
8 design, construction, operations, maintenance, integrity management  
9 and pipeline safety. I am a managing director and co-founder of the  
10 Blacksmith Group (Blacksmith), and a principal of Process Performance  
11 Improvement Consultants, a Blacksmith subsidiary. Through both of  
12 these positions, I provide consulting services to pipeline operators in  
13 areas including risk management and regulatory compliance. I also  
14 provide consulting services to industry trade associations and research  
15 organizations, particularly in the areas of industry standards, pipeline  
16 safety regulations, and best practices in risk and integrity management.  
17 I also work with pipeline operators to audit their regulatory compliance  
18 plans, help them interpret pipeline safety and integrity federal  
19 regulations, and tailor their programs to meet these standards. In my  
20 consulting practice, I have conferred extensively with pipeline operators  
21 concerning their practices, both currently and historically.

22 My professional experience in the gas pipeline industry spans thirty-  
23 five years. I have been extensively involved in pipeline design and  
24 safety. Prior to co-founding Blacksmith, I served as the Vice President  
25 of the Hartford Steam Boiler Inspection and Insurance Company's  
26 (HSB) Pipeline Group. At HSB, I counseled pipeline operators in areas  
27 such as pipeline integrity management, risk management, and  
28 emergency response protocols. I was also consulted for my expertise in  
29 the areas of pipeline operations, safety regulations, and maintenance  
30 processes. Before joining HSB, I was the Manager of Pipeline Safety at  
31 Columbia Gas Transmission. In this role, I oversaw the company's  
32 regulatory compliance, risk management, and emergency response  
33 programs. Among other positions, I have also served as Tenneco  
34 Energy's Director of Pipeline Services, where I was responsible for

1 pipeline integrity and safety projects. I also served as Manager of  
2 Engineering at Panhandle Eastern Corporation, where I focused on  
3 compliance with regulatory and consensus standards, led design and  
4 development of the company's first geographic information system (GIS)  
5 database, and was responsible for the company's engineering records  
6 systems relating to operations, maintenance, and construction. At  
7 Panhandle Eastern, I was also responsible for quality assurance (QA)  
8 for the company's design and construction programs. In addition, I was  
9 the Manager of Engineering at Colorado Interstate Gas Company,  
10 where I ensured that all facilities were built and maintained in  
11 accordance with government regulations and consensus codes  
12 and standards.

13 I have actively participated in industry-related professional  
14 organizations for most of my career. I was Chairman of the Gas Piping  
15 Technology Committee's Transmission Division, and Chairman of the  
16 Gas Technology Institute's Integrity Maintenance and Systems  
17 Operations Group for eight years, respectively. I served as Chairman of  
18 the Interstate Natural Gas Association of America (INGAA) Pipeline  
19 Safety Committee for nearly a decade. I have also served on an INGAA  
20 Task Force charged with developing methods to systematically improve  
21 pipeline integrity management practices, and co-led the drafting of the  
22 Integrity Management Standard for natural Gas Transmission Pipelines,  
23 published by the American Society of Mechanical Engineers (ASME)  
24 in 2002.

25 I have been extensively involved in the creation of pipeline-related  
26 rules and standards throughout my professional career. For the past 30  
27 years, I have been a member of ASME's B31.8 Section Committee; this  
28 Committee revises and issues interpretations of ASME B31.8 – an  
29 industry standard covering the design, fabrication, inspection, testing,  
30 and other safety aspects of the operation and maintenance of gas  
31 transmission and distribution systems. I was one of the lead authors of  
32 the original B31.8S, published in 2002, and I have continued to update it  
33 over time. In connection with my work on behalf of the Gas Technology  
34 Institute, I directed interviews of those responsible for drafting the 1955

1 edition of B31.8 (then-titled B31.1.8-1955) code provisions as well. As a  
2 member of the B31.8 Committee, I have also become very familiar with  
3 the practices of many companies operating gas pipelines.

4 I am a member of the National Association of Corrosion Engineers  
5 (NACE), and have served on a number of committees within that  
6 organization. I have assisted NACE, the American Society for  
7 Nondestructive Testing, and the American Petroleum Institute in  
8 coordinating their standards with those created by the ASME.

9 Moreover, I have worked with INGAA to help ensure that rules drafted  
10 by the Federal Office of Pipeline Safety reflect the practical realities of  
11 pipeline operations.

12 In 1995, I was appointed by the Secretary of Transportation to the  
13 Department of Transportation (DOT) Technical Pipeline Safety  
14 Standards Committee – an appointment I held for two terms. I have  
15 been called to testify on behalf of the gas industry before the United  
16 States Congress on matters related to pipeline safety. Furthermore, I  
17 was a member of the DOT Risk Management Quality Action Team, and  
18 the DOT Mapping Quality Action Team.

19 I earned a Bachelor of Science in Electrical Engineering from the  
20 University of Colorado in 1977, and a Master of Science in Business  
21 Administration from the University of Northern Colorado in 1981. My  
22 curriculum vitae is included as Appendix A to this Chapter.

#### 23 **b. Materials Reviewed**

24 My analysis and conclusions are based on, among other things, a  
25 review and analysis of data and records concerning the physical assets  
26 and operations of PG&E's gas transmission Line 132; materials relating  
27 to PG&E's Integrity Management program; sworn interviews and  
28 testimony regarding the San Bruno accident and the operation of  
29 PG&E's Integrity Management program, including from third-parties; the  
30 National Transportation Safety Board report on the accident; testimony  
31 prepared by the CPUC's Consumer Protection and Safety Division  
32 (CPSD); testimony prepared by John Gawronski on behalf of the City  
33 and County of San Francisco; the report and testimony of Margaret Felts

1 on behalf of the CPSD; and a visual examination of segments of gas  
2 transmission Line 132, including portions of Segment 180.

3 My analysis and conclusions are also based on third-party  
4 publications and studies regarding the gas pipeline industry and data  
5 reported to third-parties by gas pipeline operators, including, but not  
6 limited to, incident data reported to the DOT and valve data reported to  
7 INGAA. In addition, my analysis and conclusions are based upon my  
8 discussions with gas pipeline operators concerning their practices over  
9 the years in operating and testing their pipelines.

## 10 **2. ANALYSIS AND CONCLUSIONS**

### 11 **a. Missing or Incomplete Records for Pipelines Installed Prior to 1970** 12 **are Common in the Gas Pipeline Industry**

13 The federal pipeline safety regulations set forth in 49 CFR Part 192  
14 (Part 192) became effective in November of 1970. Nearly two-thirds of  
15 onshore natural gas transmission pipelines in service today were  
16 installed prior to this date. These pipelines were generally installed and  
17 had their maximum allowable operating pressure (MAOP) established  
18 under the ASA B31.1 standard (for pipelines installed from 1933-1951),  
19 the ASME B31.8<sup>2</sup> standard (for pipelines installed in and after 1952), or  
20 the internal standards maintained by individual operators.

#### 21 **(1) Impact of the Grandfather Clause on Operator Recordkeeping** 22 **Practices and Record Utilization**

23 Based on my experience in the industry, I believe that after Part  
24 192 took effect, many operators generally established the MAOP  
25 for some portion of their natural gas pipelines installed prior to 1970  
26 through the method articulated in Section 192.619(c) (the  
27 grandfather clause). The grandfather clause provided that  
28 “notwithstanding” the provisions of 192.619(a) and (b) (which,  
29 briefly summarized, provided that pipelines must be operated at an  
30 MAOP derived from the lowest of three specific measures),  
31 operators were permitted to rely upon records establishing the  
32 highest operating pressure to which the pipeline was subjected

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<sup>2</sup> Originally titled ASA B31.1.8-1952.

1 between 1965 and 1970 to establish the MAOP. After this point,  
2 operators may have consulted records relating to their  
3 grandfathered pipes (such as strength tests or design  
4 specifications) for purposes of maintenance, establishing class  
5 location or performing integrity management assessments.  
6 However, after establishing a pipe's MAOP under the grandfather  
7 clause operators did not generally revisit these historical records in  
8 connection with the MAOP for those pipes.

9 PHMSA has recognized the historical impact of the grandfather  
10 clause on industry recordkeeping practices. In a May 7, 2012  
11 advisory bulletin regarding operators' verification of records,  
12 PHMSA indicated that "[t]he third method, often referred to as the  
13 'grandfather clause,' allows pipelines that had safely operated prior  
14 to the pipeline safety MAOP regulations to continue to operate  
15 under similar conditions *without retroactively applying*  
16 *recordkeeping requirements* or requiring pressure tests" (emphasis  
17 added). (PHMSA Advisory Bulletin, 77 Fed. Reg. 26822, 26823  
18 (May 17, 2012) (Ex. 3-1).) PG&E's well-publicized and wide-  
19 ranging efforts to locate strength test pressure and material records  
20 for its formerly grandfathered pipes should be evaluated against the  
21 historical de-emphasis of such records for purposes of  
22 establishing MAOP.

## 23 **(2) Historical Recordkeeping in the Natural Gas Industry**

24 Among other requirements, the new regulations introduced in  
25 Part 192 in 1970 mandated that operators maintain certain records  
26 relating to the design, construction, operation, and maintenance of  
27 transmission pipeline systems, including records sufficient to  
28 establish the MAOP for a given transmission pipeline. However,  
29 common sense and historical perspective suggest that the quality  
30 of records maintained by pipeline operators will vary with the age of  
31 the pipe in question. Over the years, many operators misplaced or  
32 discarded various underlying source materials reflecting pipeline  
33 characteristics or operating history after using such materials to  
34 establish a pipeline's MAOP. Many operators have also been party

1 to reorganizations, changes in ownership structure and the  
2 acquisition and divestiture of various assets, further complicating  
3 efforts to maintain complete and accurate historical records. In my  
4 experience, it is very common for pipeline operators to have  
5 missing or incomplete records for various pipelines or pipe  
6 segments in their respective systems, particularly for pipelines  
7 installed prior to 1970.

8 **b. Prior to 2004, Pipeline Records Were Not Generally Utilized to Ensure**  
9 **the Structural Integrity of Natural Gas Pipelines**

10 Prior to the 2004 effective date of the 2002 Pipeline Safety  
11 Improvement Act and subsequent regulations, which I discuss in greater  
12 detail below, the industry viewed the primary purpose of pipeline records  
13 retained by operators as a way to document and verify compliance with  
14 regulations and the completion of certain safety-related actions such as  
15 the design and construction of pipe according to certain specifications,  
16 the completion of routine pipeline patrols, the conduct of leak surveys or  
17 the repair of any detected leaks within a specified timeframe. Operators  
18 were *not* generally required to utilize such records for the purpose of  
19 determining the condition of their pipelines or of specific pipe segments.  
20 While a limited number of operators had started to experiment with  
21 records-based “risk management” practices prior to the era in which the  
22 integrity management principles discussed below were adopted,  
23 operators did not generally utilize pipeline records for purposes of  
24 ensuring the systematic, comprehensive and integrative structural  
25 integrity of their pipelines.

26 **c. The Development of Integrity Management Programs Enhanced**  
27 **Operators’ Integration and Utilization of Pipeline Data**

28 In the wake of the Bellingham and Carlsbad pipeline accidents of  
29 1999 and 2000, respectively, government regulators and the gas  
30 pipeline industry worked together to develop a system to manage  
31 structural threats that might impact the safe operation of gas  
32 transmission pipelines. Arguably the most significant pipeline safety  
33 legislation in decades, Congress enacted the Pipeline Safety  
34 Improvement Act of 2002, in which specific regulations relating to

1 integrity management (Integrity Management) programs were born. The  
2 Integrity Management rules did not materially alter the nature of  
3 historical pipeline data that operators were required to maintain. Rather,  
4 the rules provided operators with a structure for integrating this historical  
5 pipeline data into a comprehensive assessment of the integrity of  
6 pipelines in service and provided guidance regarding the creation and  
7 maintenance of certain records specific to the Integrity  
8 Management process.

9 **(1) The Integrity Management Regulations Recognized the Inherent**  
10 **Limitations of Pipeline Records and Introduced the Assessment**  
11 **Method for Evaluating Risk in Light of these Limitations**

12 The Integrity Management rules developed in the early 2000s  
13 were in part motivated by the evolving understanding among  
14 industry participants and government regulators that historical  
15 records, while informative, did not always provide enough  
16 information relating to the current state of many pipelines in  
17 operation, and that the then-current operations and maintenance  
18 requirements could not always ensure the safe operation of  
19 pipelines. The Integrity Management rules were drafted with the  
20 expectation that existing pipeline records would provide information  
21 sufficient to make reasonable, conservative assumptions about the  
22 present condition of pipe in operation, but that additional measures  
23 were required to account for a variety of threats. For example, pipe  
24 located in highly-corrosive soil that has experienced periods of  
25 inadequate cathodic protection would suggest to an operator that  
26 the pipe might have sustained corrosion, but could not state the  
27 volume of metal loss on the pipe at issue or the extent of corrosion  
28 on other similar segments. The Integrity Management rules thus  
29 required operators to conduct integrity assessments of their  
30 pipelines in order to validate existing assumptions and/or provide  
31 information that would either change or confirm the assumptions  
32 and, potentially, lead to additional assessment, examination,  
33 evaluation, and remediation. These ongoing Integrity Management  
34 assessments were intended in part to address known and



1 anticipated gaps in operators' knowledge about their  
2 pipeline systems.

3 **(2) The Integrity Management Regulations Took into Account the**  
4 **Well-Recognized Nature of Incomplete Pipeline Records**  
5 **Throughout the Gas Industry**

6 Through incorporation of ASME B31.8S (titled Managing  
7 System Integrity of Gas Pipelines) into Part 192, the federal  
8 rulemaking process recognized and sought to account for the well-  
9 known limitations of record-keeping throughout the industry. While  
10 ASME B31.8S provides that “[c]omprehensive pipeline and facility  
11 knowledge is an essential component of a performance-based  
12 integrity management program,” it also allows an operator to use  
13 the prescriptive process where the operator lacks sufficient data.  
14 (ASME B31.8S § 4.1.) This is reflected more strongly in the case of  
15 operators such as PG&E implementing prescriptive Integrity  
16 Management programs, who are to gather the “[l]imited data sets”  
17 articulated in Appendix A. (§ 4.2.1.) For example, for a  
18 manufacturing threat assessment, this data includes (a) pipe  
19 material, (b) year of installation, (c) manufacturing process, (d)  
20 seam type, (e) joint factor, and (f) operating pressure history.  
21 (§ 4.2.) For both the prescriptive and performance-based  
22 programs, ASME B31.8S contemplated that the assessment  
23 process would augment existing records by providing information  
24 from inspection, examination, and evaluation data. (§ 4.3.)

25 ASME B31.8S specifically recognizes that operators may not  
26 possess complete historical records, and articulates steps  
27 permitting operators to substitute conservative assumed values  
28 where pre-existing documentation is lacking. In the case of  
29 manufacturing threats, operators are further permitted to reference  
30 sources such as the *History of Line Pipe Manufacturing in North*  
31 *America* to fill in missing pipe specifications. (§ A4.2.)

1           **d. Ms. Felts' Critiques of PG&E's Recordkeeping and Regulatory**  
2           **Compliance are Inaccurate and Unfounded**

3           I have reviewed and analyzed the report of Margaret Felts submitted  
4           in this proceeding. Ms. Felts offers a critique of PG&E for its alleged  
5           failure to maintain records relating to pipeline operating pressure history,  
6           x-ray records, and weld maps. Based upon my professional experience  
7           in the industry and knowledge of pipeline safety and integrity  
8           management regulations, I disagree with Ms. Felts' conclusions.

9           As a preliminary matter, Ms. Felts does not identify any  
10          recordkeeping requirements in the Integrity Management rules or within  
11          ASME B31.8S that require an operator to maintain historical records of  
12          the sort listed above, nor am I personally aware of any such  
13          requirements based on my extensive experience in the industry. For  
14          example, operators are not required to maintain records of  
15          over-pressure events on transmission lines unless such events  
16          exceeded 110% of MAOP or 75% of SMYS. The Integrity Management  
17          rules do require retention of pressure history records for the specific  
18          types of pipe enumerated in 49 C.F.R. §§ 192.917(e)(3) and (e)(4). For  
19          those pipeline segments identified as subject to manufacturing threats  
20          specific to the pipe seam and operating in a high consequence area  
21          (HCA), the rules require that an operator limit the maximum pressure to  
22          no greater than the highest operating pressure in the five years prior to  
23          identification of the HCA, or, in the alternative, to conduct a hydro test of  
24          the pipe in question.

25          The rules requiring operators to implement Integrity Management  
26          programs mandated compliance by December 17, 2004, meaning that  
27          PG&E was required to limit operating pressure on pipes operating in  
28          HCAs to no greater than the highest pressure experienced since 1999.  
29          Missing or incomplete operating pressure data for 1999 would not have  
30          a discernable negative impact on PG&E's determination and  
31          assessment of a manufacturing threat under this rule. If a pipeline  
32          reached its highest historical operating pressure in 1999, and PG&E  
33          lacks documentation of such an event, the consequence is that PG&E  
34          has subsequently operated the pipeline at a maximum pressure *lower*

1 than that to which the pipe has previously been subjected. If a pipeline  
2 operated throughout 1999 at a pressure *below* its highest historical  
3 operating pressure, then data to that effect would not inform PG&E's  
4 establishment of the highest operating pressure for that pipe.

5 Ms. Felts' claims regarding the consequence of missing or  
6 incomplete records of x-ray film, girth weld inspection reports and weld  
7 maps are similarly inaccurate. Federal regulations do not currently  
8 require, and have not historically required, operators to subject all girth  
9 welds on their system to x-ray inspection, nor am I aware of any  
10 requirement that operators maintain film of those girth weld x-rays that  
11 they do conduct. For Integrity Management purposes, operators utilize  
12 information or conservative assumptions regarding the vintage and  
13 method of welding employed on their pipelines, given that particular  
14 construction methods such as acetylene girth welding have proven  
15 susceptible to ground movement regardless of the size or quantity of  
16 imperfections in the girth weld. Operators often derive such knowledge  
17 or conservative assumptions regarding the welding method employed  
18 from records relating to construction of the pipeline in question.

19 I have also reviewed and considered Ms. Felts' statements  
20 regarding PG&E's use of reconditioned pipe in its system. Again, I  
21 disagree with Ms. Felts' conclusions. The use of reconditioned pipe  
22 without specific inspection practices was common within the gas  
23 industry into the late 1960s. Ms. Felts accurately states that since the  
24 1970 enactment of part 192.13, reusing pipe has been an acceptable  
25 practice when the salvaged pipe is subjected to the requisite inspection  
26 and testing to affirm its structural integrity prior to reinstallation. Absent  
27 evidence of structural damage revealed during the inspection, or known  
28 concerns regarding potential manufacturing defects (such as particular  
29 historical vintages of A.O. Smith pipe identified in the 1980s as subject  
30 to potential defects), pipe can reasonably be reconditioned and  
31 reinstalled regardless of its age. While Ms. Felts asserts that it would be  
32 "prudent" for operators to track the age of reconditioned pipe in their  
33 systems, Ms. Felts does not cite any historical regulation requiring such

1 a practice, nor am I aware of any such regulation for pipe installed prior  
2 to 1970.

1 **CHAPTER 3B**  
2 **PG&E'S GAS TRANSMISSION SYSTEM**

3 This section, which was filed as Chapter 1A of PG&E's June 20, 2011 filing,  
4 provides an overview of PG&E's transmission system, including its  
5 historical development.

6 Natural gas has been distributed by pipeline in some areas of the country for  
7 over a hundred years. (GTH-48.)<sup>3</sup> Pipeline systems expanded to meet demand  
8 during strong economic cycles and in response to population changes. More than  
9 sixty percent of the Nation's gas transmission pipelines were installed before federal  
10 regulations took effect in 1970. (GTH-61.) Some gas transmission and distribution  
11 utilities, such as PG&E, which began as small operations, grew through mergers or  
12 acquisitions to service a larger territory. Their systems changed character as  
13 interstate transportation of natural gas became more prevalent following World War  
14 II. The transmission systems of these companies tend to be heterogeneous,  
15 meaning that their pipeline systems are of different age, materials, diameter,  
16 pressure, and specifications.

17 The term heterogeneous aptly characterizes PG&E's transmission system.  
18 PG&E's service territory is large; and its pipeline construction, maintenance and  
19 operations activities stretched across a large part of California. A significant portion  
20 of PG&E's existing transmission system was installed before extensive pipeline  
21 safety regulation, before pipeline recordkeeping regulations, and before  
22 technological changes that have improved modern data management and retrieval  
23 processes. The existing pipeline system is diverse in terms of its specifications and  
24 its age. For these reasons, it is difficult to generalize about the system's design and  
25 construction or PG&E's historic maintenance and operations practices.

26 **1. An Overview of PG&E's Existing Transmission System**

27 PG&E serves 15 million natural gas and electric customers (4.3 million  
28 individual gas accounts) in northern and central California. Its service  
29 territory covers 70,000 square miles.

30 The system comprises approximately 6,750 miles of pipeline operating  
31 at pressures greater than 60 pounds per square inch gauge (psig),  
32 approximately 40 miles of gas gathering pipeline, and more than 42,000

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<sup>3</sup> All references to attachments can be found in the June 20, 2011 filing.

1 miles of distribution pipe that operate at a pressure of 60 psig or less. Of the  
2 6,750 miles of gas transmission pipe, approximately 5,800<sup>4</sup> miles meet the  
3 definition of a Department of Transportation (DOT) Gas Transmission  
4 pipeline. See 49 C.F.R. § 192.3. By comparison, Southern California Gas  
5 Company, the nation's largest natural gas transmission and distribution  
6 utility by customer count, has approximately 3,989 miles of high pressure  
7 gas transmission pipeline. (GTH-49.)

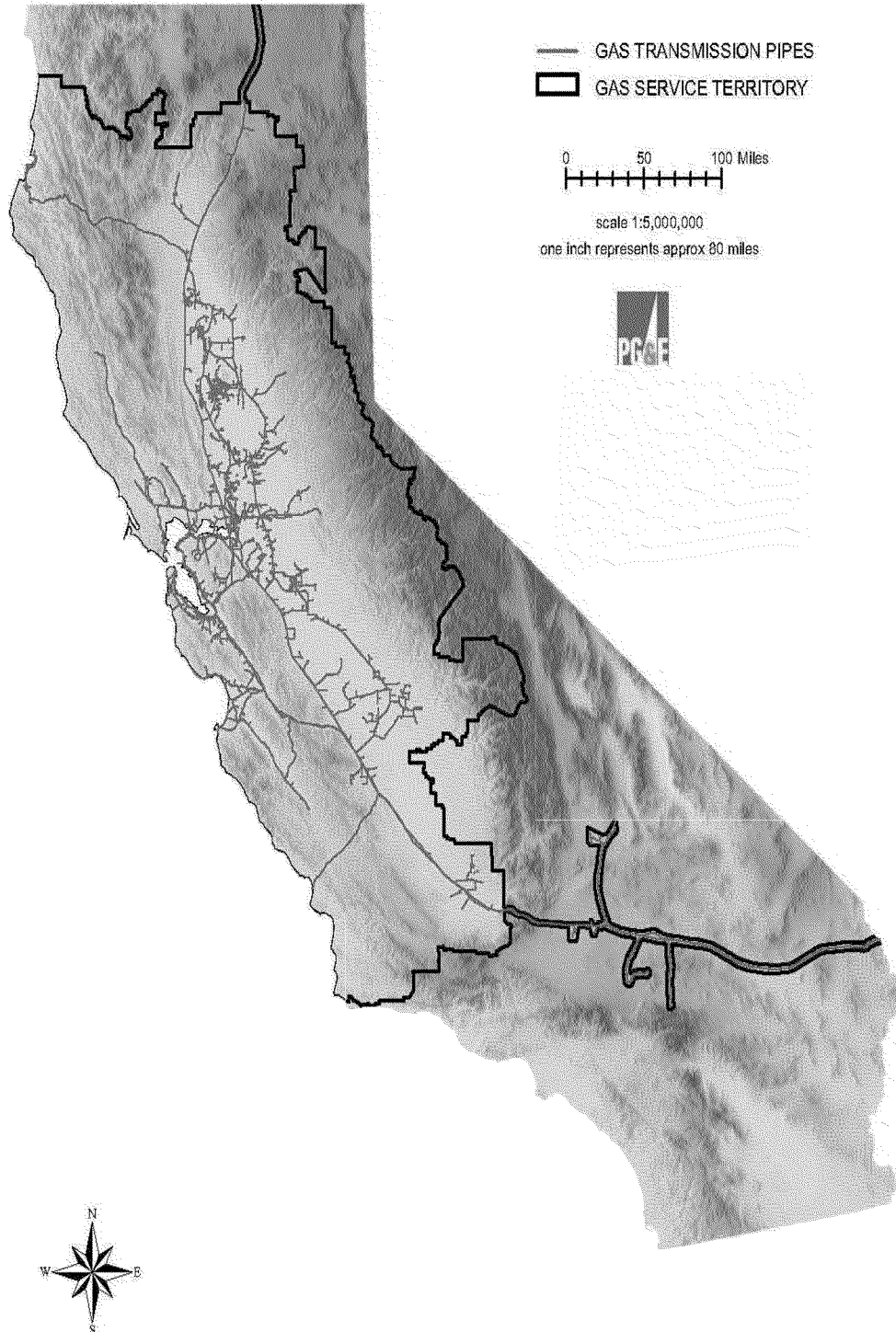
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<sup>4</sup> See 2009 PHMSA F 7100.2-1 forms, Pacific Gas and Electric Co (operator #15007) and Standard Pacific Gas Line, Inc. (operator #18608) (GTH-60).

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**FIGURE 3B-1  
PACIFIC GAS AND ELECTRIC COMPANY  
PG&E GAS TRANSMISSION PIPES**

## **PG&E GAS TRANSMISSION PIPES**



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PG&E operates both backbone and local transmission lines. Backbone lines are larger diameter pipelines that receive and carry gas from interstate

1 sources. Local transmission lines deliver gas to local distribution networks,  
2 from which the gas is delivered to most customers.

3 As the map below depicts, PG&E's backbone lines extend virtually the  
4 entire length of the state.

5 **FIGURE 3B-2**  
6 **PACIFIC GAS AND ELECTRIC COMPANY**  
7 **PG&E'S BACKBONE SYSTEM**



8 PG&E's backbone lines extend approximately 850 miles from Topock,  
9 California in the south, to Malin, Oregon in the north. Lines 400 and 401  
10 make up the northern facilities of the system, Lines 300 A&B the southern  
11 facilities, and Lines 107, 114, 131 and 303 the Bay Area Loop. These  
12 backbone lines are large diameter pipelines (30" to 42") with Maximum  
13 Allowable Operating Pressures (MAOP) between 475 and 1,140 psig.

14 Combined, the backbone system consists of approximately 2,000 miles  
15 of pipeline, representing 35 percent of PG&E's gas transmission system.  
16 There are eight compressor stations along the backbone, five supporting L  
17



1 400/401/402 and three supporting L 300A&B. These facilities help move  
2 gas from the various interstate receipt points to customers throughout  
3 PG&E's service territory. The backbone system is primarily maintained by  
4 PG&E gas technicians and mechanics assigned to PG&E maintenance  
5 facilities, including those at Topock, Hinkley, Kettleman City, Tracy, Los  
6 Medanos, McDonald Island, Willows, Burney, Rio Vista and Milpitas.

7 PG&E's backbone gas transmission pipeline system is designed to  
8 transport up to 3.1 billion cubic feet per day of natural gas from interstate  
9 pipeline receipt points at the northern and southern California borders, Malin  
10 and Topock, respectively, to metropolitan areas and customers within the  
11 San Francisco Bay Area, Sacramento and San Joaquin Valley. In 2009,  
12 roughly 50% of PG&E's natural gas supply was received at Malin, Oregon  
13 from either Canada or the Rocky Mountain areas. (GTH-50.) Approximately  
14 40% of PG&E's natural gas supply originated in the Southwest and was  
15 received at Topock, California. Natural gas reserves within California,  
16 mostly from the Sacramento Valley, accounted for only 6 percent of PG&E's  
17 supply. The small remainder was received at the Nevada/California border  
18 from the Rocky Mountain area. These relative percentages vary from year-  
19 to-year depending on gas market conditions.

## 20 **2. Local Transmission System**

21 PG&E's local transmission system consists of approximately 3,600 miles  
22 of DOT defined gas transmission pipelines. The local transmission facilities  
23 include PG&E's non-backbone numbered transmission lines, distribution  
24 feeder mains, and PG&E's six-sevenths interest in the Stanpac Line. To a  
25 significant extent, local transmission lines are maintained by personnel  
26 working out of one of PG&E's numerous division offices located throughout  
27 PG&E's service territory.

28 Other DOT defined pipeline segments operated by PG&E include  
29 underground storage field gathering lines, high pressure customer lines,  
30 local gas gathering and station piping, totaling approximately 200 miles.  
31 PG&E maintains large gas storage facilities at McDonald Island, Los  
32 Medanos and Pleasant Creek. PG&E also has interconnections with  
33 additional storage facilities at Wild Goose and Lodi. These storage facilities

1 contribute to the management of the supply of natural gas during peak  
2 demand periods.

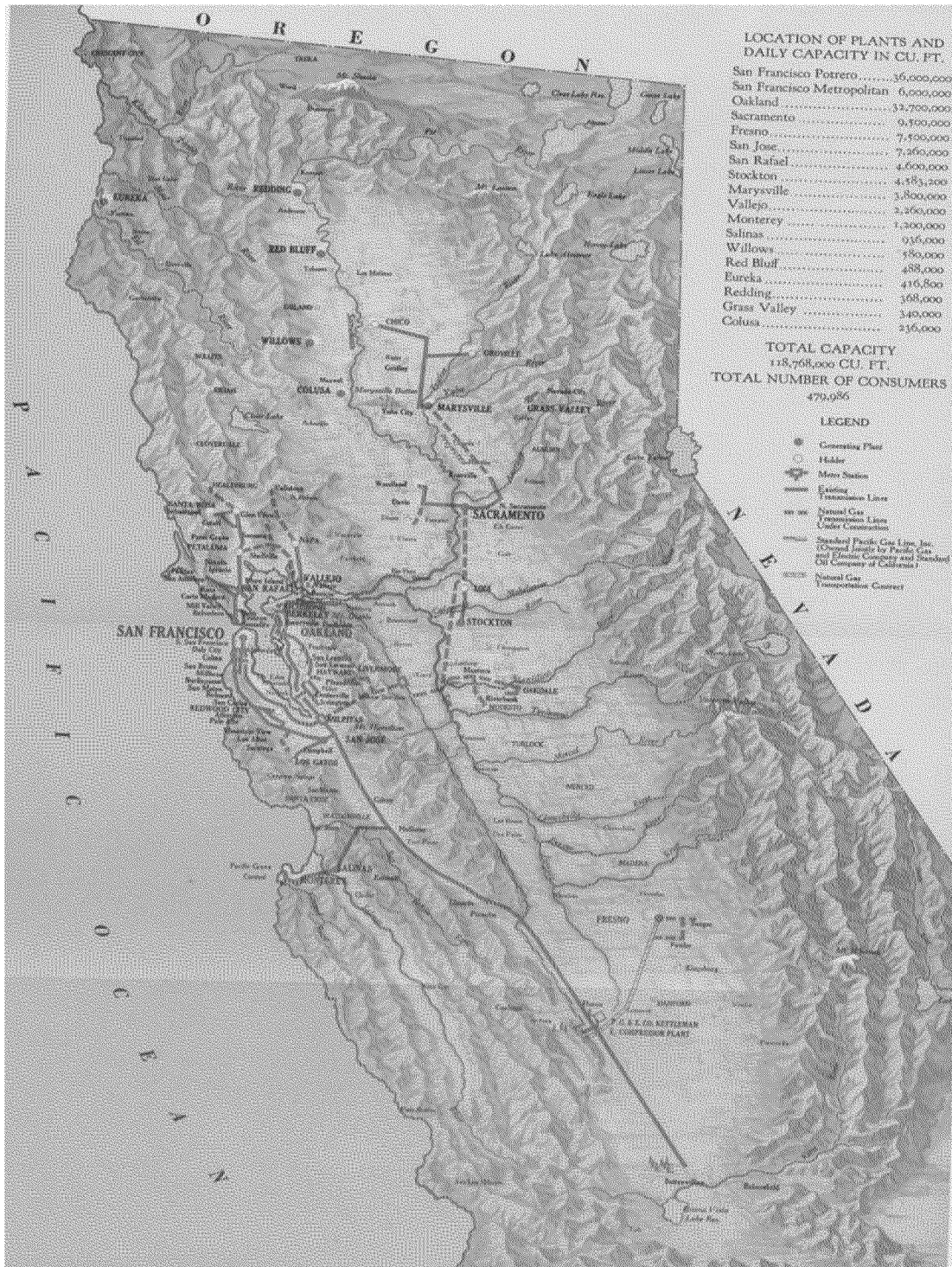
3 **a. The Growth of PG&E's Gas Transmission System**

4 **(1) Early Natural Gas Transmission Lines**

5 PG&E's present-day natural gas transmission system has its  
6 beginnings in the late 1920s. In that era, large natural gas reserves  
7 were identified and extracted at Buttonwillow and Kettleman Hills.  
8 (GTH-1.) In January 1929, PG&E began construction of pipelines  
9 that brought natural gas from these fields to various locations,  
10 including the Milpitas metering station. At Milpitas, a pipeline was  
11 constructed along the eastern shore of the Bay to Oakland and  
12 Richmond, while the main corridor was run 44 miles to San  
13 Francisco. (GTH-51.) Before 1950, all of PG&E's gas supply  
14 originated from sources in California. (GTH-52.) The transmission  
15 system in these early days was comparatively small, as the map of  
16 PG&E's gas transmission system in 1929 depicts.

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**FIGURE 3B-3  
PACIFIC GAS AND ELECTRIC COMPANY  
PACIFIC GAS & ELECTRIC GAS TRANSMISSION SYSTEM 1929**



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The transmission system expanded and became increasingly integrated in the 1930s to bring additional sources of gas supplies to new customers. By the end of 1930, 183,000 customers in San Francisco had converted to natural gas from heating oil or other

1 sources. (GTH-53.) During the 1930s, additional natural reserves were  
2 discovered and extracted at the McDonald Island and Rio Vista fields.  
3 (GTH-51.) Transmission lines were constructed to expand system  
4 capacity and transport gas from those fields to population centers. By  
5 1936, for example, PG&E had installed a second transmission line from  
6 Milpitas to San Francisco. (RH-132.); (GTH-2.)

### 7 **3. The Post World War II System Expansion**

8 In the 1940s and 1950s, California's population and industrial base grew  
9 significantly. Between 1940 and 1953, the population in the forty-six  
10 California counties PG&E served grew 73%, from 3,281,874 in 1940 to  
11 5,675,000 in 1953. (GTH-7.) In 1940, there were 658,830 PG&E gas  
12 customers in California. (GTH-3.) By 1953, PG&E increased its gas  
13 customers by 81 percent to 1,194,098. (GTH-7.) Defense and other  
14 industries also expanded, placing increased demands on the system.

15 PG&E's transmission system grew to keep pace with increased  
16 demand. In 1947, PG&E began to purchase natural gas from the Southern  
17 California and Southern Counties Gas Companies. (GTH-51.) In 1950,  
18 PG&E had completed construction on a 34 inch diameter, 503 mile long gas  
19 transmission line running from Milpitas to Topock, California to connect to a  
20 third-party interstate line transporting gas from Texas and New Mexico.  
21 PG&E's Milpitas to Topock line had the capacity to deliver 400 million cubic  
22 feet of gas daily from fields in Texas and New Mexico. (GTH-5.) At the  
23 time, the Topock-Milpitas pipeline was the largest diameter pipeline ever  
24 constructed for the transmission of natural gas. (GTH-54.) In the few short  
25 years between 1947 and 1952, the source of PG&E's natural gas supplies  
26 shifted. In 1947, 100% of those supplies came from California fields. By  
27 1952, that figure would shrink to less than 50%. (GTH-6.) Today, it is less  
28 than 10%.

29 In addition to expanding its transmission system, PG&E grew by  
30 acquiring smaller utilities, including gas distribution utilities. (GTH-55.)  
31 PG&E merged with the San Joaquin Light and Power Corporation in 1938,  
32 and Pacific Public Service Company in 1954. In other instances, the  
33 company purchased the facilities of other utilities. Thus, for example in  
34 1944, it purchased the butane-air system owned by Coast Counties Gas and

1 Electric Company in Arcata and subsequently converted the system so that  
2 it could supply natural gas.

3 So great was the demand for natural gas that just as PG&E was  
4 completing the 503 mile Topock-Milpitas pipeline in 1950, it initiated plans to  
5 parallel a portion of the line with an additional 34-inch diameter pipe and to  
6 install additional compressor units to increase supply. Construction on the  
7 second line began in 1952 and, by 1957, the Company had paralleled the  
8 entire 503 miles. (GTH-11.) Daily capacity of the completed Topock-  
9 Milpitas pipeline nearly tripled since its first use in 1950. (GTH-56.) By  
10 1957, 70% of PG&E's gas supply originated from fields in Texas and New  
11 Mexico. (GTH-11.) This extraordinary post-World War II expansion of gas  
12 pipeline facilities, including the installation of the two Topock-Milpitas lines,  
13 was part of what was then the largest gas and electric system expansion  
14 ever undertaken by any utility in the United States. (GTH-51.)

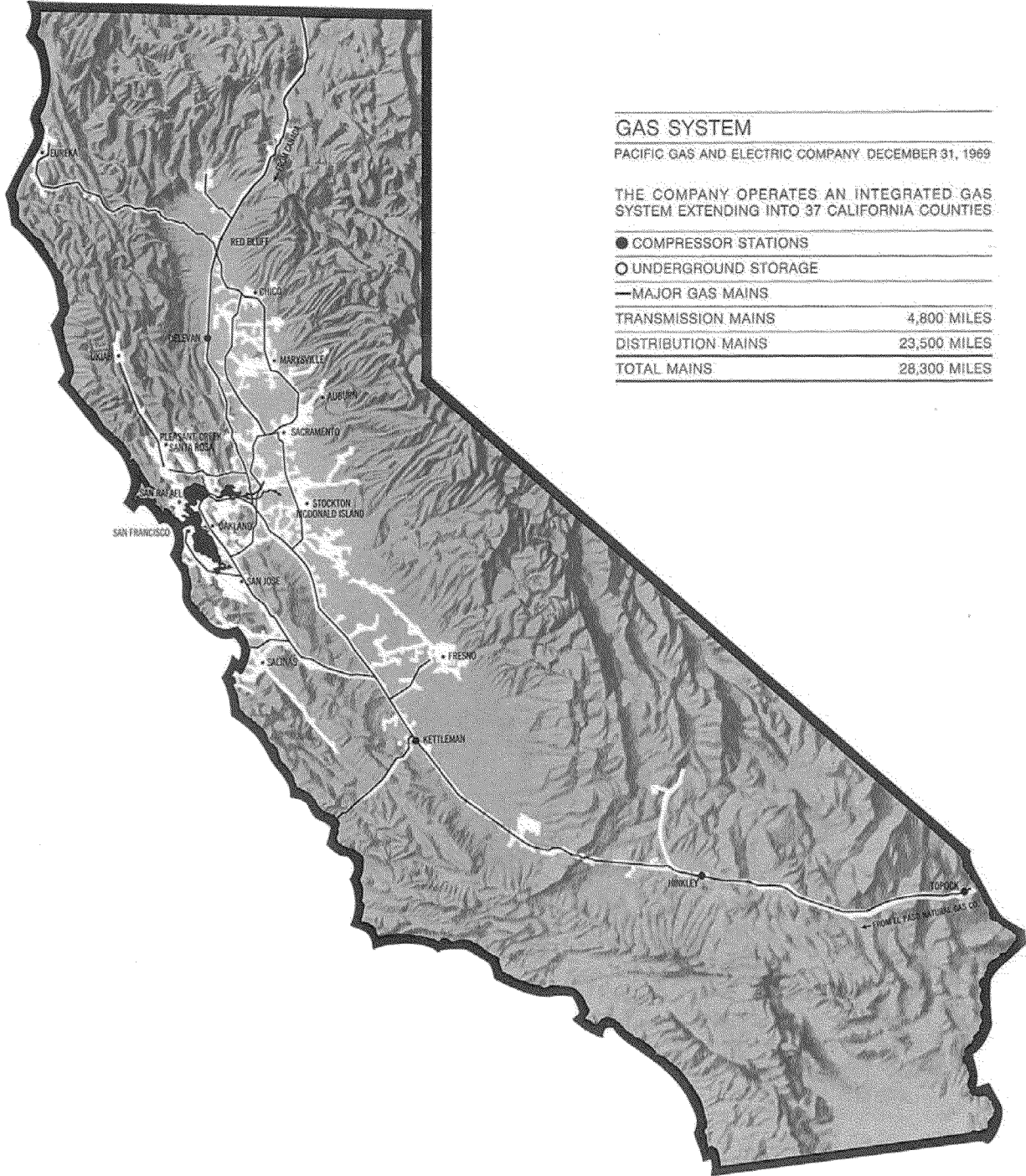
15 PG&E continued to expand its gas facilities throughout the 1950s. In  
16 1956, the Company started work on several major projects. It converted a  
17 partially depleted gas field in Yolo County into the Company's first natural  
18 gas underground storage area. It constructed an 83-mile line in a southerly  
19 direction to Sacramento. It built a 175-mile line from northern Sacramento  
20 Valley to Eureka, traversing the Coastal Mountain Range. In addition, new  
21 reserves of natural gas in Northern California were discovered. (GTH-10.)  
22 PG&E's wholly-owned subsidiary, Natural Gas Corporation of California,  
23 drilled two additional wells and formulated plans for additional drilling in  
24 1957 on leaseholds adjacent to the successful wells.

25 The next year, in 1958, PG&E bought the McDonald Island field, located  
26 about 50 miles east of San Francisco. (GTH-12.) The field included eleven  
27 wells and an 18-inch main that connects the field to the PG&E main gas  
28 transmission system. To meet peak demands, the field could put up to 400  
29 million cubic feet per day of gas into the system. (GTH-15.) Construction of  
30 Line 400, which connected California to Alberta, Canada, was complete by  
31 1961. The 36-inch diameter line stretched 1,400 miles from Alberta to  
32 California. It provided the capacity to transport a maximum of 454 million  
33 cubic feet of gas per day, representing over 20% of PG&E's total natural gas  
34 supply in 1961.

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Thus, on the eve of the first federal pipeline safety regulations in 1970, PG&E's transmission system had expanded significantly over the years to include 4,800 miles of transmission mains. The following map depicts the system as it existed in 1969.

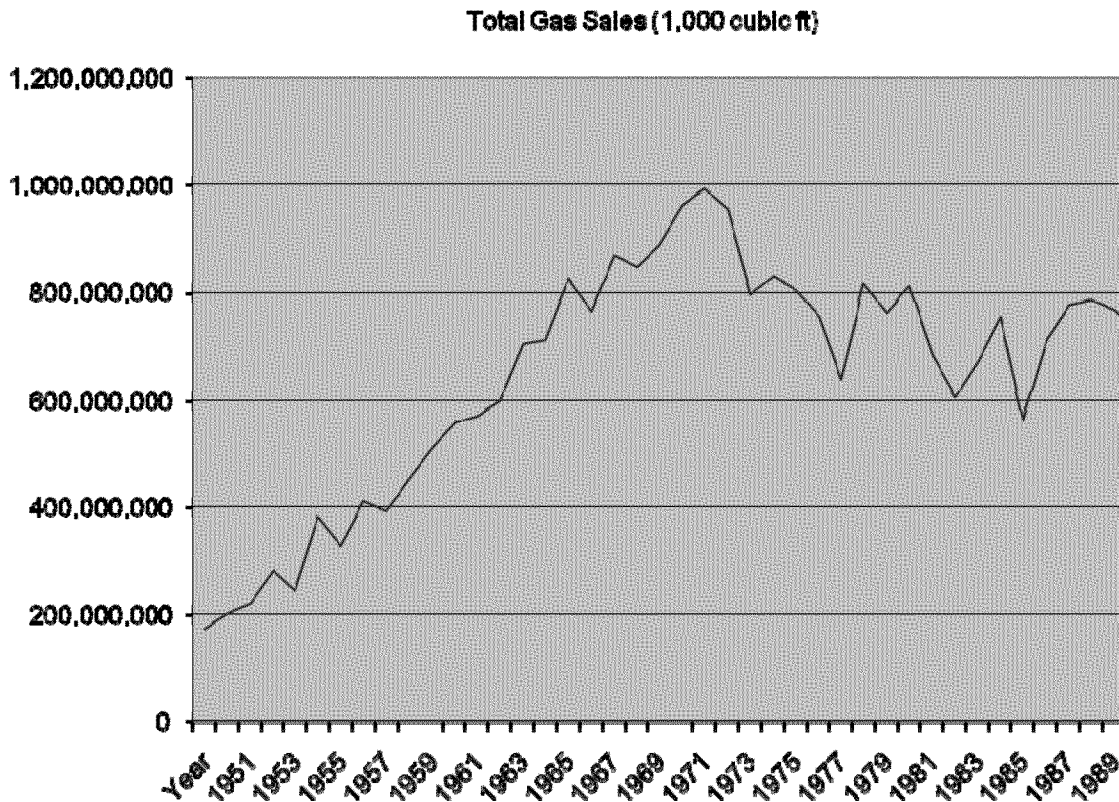
**FIGURE 3B-4  
PACIFIC GAS AND ELECTRIC COMPANY  
PG&E GAS TRANSMISSION SYSTEM 1969**



8

1 The gas transmission system continued to expand after 1970, but at a  
 2 slower rate than seen in previous years. In the 1970s, the Company  
 3 contended with a shortage of gas supply resulting in rising natural gas  
 4 prices. By 1975, PG&E paid an average price of 97 cents per thousand  
 5 cubic feet for its natural gas representing a 205% increase over the price in  
 6 1970. (GTH-29.) The gas shortage and rise in prices were among the  
 7 factors that contributed to a reduction in the customer demand for natural  
 8 gas. As the chart below depicts, the upward trend in the volume of gas  
 9 sales began to flatten and then fall in the early 1970s:<sup>5</sup>

10 **FIGURE 3B-5**  
 11 **PACIFIC GAS AND ELECTRIC COMPANY**  
 12 **PG&E'S TOTAL GAS SALES (1948-1990)**



13 Facing limited gas supplies and increased prices, PG&E expanded its  
 14 capability to make greater use of its underground gas storage fields. PG&E  
 15 built additional wells and completed additional pipelines connecting its  
 16 McDonald Island gas storage fields to the PG&E's gas system. (GTH-28.)  
 17

<sup>5</sup> In the mid-1970s, declining gas supply forced moderate curtailments of sales to low priority gas users. (GTH-29.)

1 The 1980s were marked by several significant events. Natural gas  
 2 prices started to fall by 1983. (GTH-37.) The national gas market  
 3 underwent restructuring. (GTH-40.) As described in more detail in Chapter  
 4 6C, PG&E formalized a program to replace existing transmission and  
 5 distribution lines. (GTH-57.) Most of the work occurred in San Francisco  
 6 and the East Bay, with work also occurring in cities such as Sacramento,  
 7 San Jose and Fresno. In the late 1980s and early 1990s, PG&E began new  
 8 pipeline facility construction. In 1991, PG&E opened its newly reconstructed  
 9 Milpitas Gas Terminal. (GTH-58.) In this same era, PG&E expanded its  
 10 ability to obtain gas supplies from Canada by constructing Line 401.  
 11 (GTH-59.) Completed in 1993, Line 401 parallels Line 400.

12 PG&E has several recent and ongoing local transmission projects to  
 13 meet increased population growth, particularly in the Central Valley. In  
 14 recent years, some of the fastest growing regions in the United States, e.g.,  
 15 Placer, south Sacramento, and Fresno counties, are located in PG&E's  
 16 service territory. PG&E recently completed construction on Line 406, a  
 17 fourteen mile pipeline in Yolo County, and is now turning to work on Line  
 18 407 from Yolo to Roseville. PG&E also expects to soon obtain increased  
 19 supplies from the proposed Ruby Pipeline, owned and operated by El Paso  
 20 Corporation, which is expected to supply over 1 billion cubic feet per day of  
 21 gas from Opal, Wyoming to Malin, Oregon. (GTH-50.)

22 **TABLE 3B-1**  
 23 **PACIFIC GAS AND ELECTRIC COMPANY**  
 24 **MILES BY SIZE**

Miles of Gas Transmission Pipelines at year end 2009, as reported in PHMSA F7100.2-1. Miles by nominal pipe size.

<b>Line No.</b>	<b>Unknown</b>	<b>4" of Less</b>	<b>Over 4" Thru 10"</b>	<b>Over 10" Thru 20"</b>	<b>Over 20" Thru 28"</b>	<b>Over 28"</b>	<b>Total</b>
Transmission	0.12	395.78	1,453.28	1,425.79	545.62	1,956.37	5,776.96
Gas Gathering	6.93	22.30	12.67	0.08	0.00	0.00	41.98
<b>Total</b>	<b>7.05</b>	<b>418.08</b>	<b>1,465.95</b>	<b>1,425.87</b>	<b>545.62</b>	<b>1,956.37</b>	<b>5,818.94</b>



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**TABLE 3B-2  
PACIFIC GAS AND ELECTRIC COMPANY  
MILES BY DECADE**

Miles of Gas Transmission Pipelines at year end 2009, as reported in PHMSA F7100.2-1. Miles by pipe by decade of installation.

<b>Line No.</b>	<b>Unknown</b>	<b>Pre- 1940</b>	<b>1940 – 1949</b>	<b>1950 – 1959</b>	<b>1960 – 1969</b>	<b>1970 – 1979</b>	<b>1980 – 1989</b>	<b>1990 – 1999</b>	<b>2000 – 2009</b>	<b>Total</b>
Transmission	35.93	267.22	435.94	1,970.67	1,173.66	356.77	549.69	794.17	192.90	5,776.96
Gas Gathering	7.88	0.00	0.42	3.95	16.06	5.41	6.84	1.41	0.01	41.98
<b>Total</b>	<b>43.82</b>	<b>267.22</b>	<b>436.36</b>	<b>1,974.62</b>	<b>1,189.72</b>	<b>362.18</b>	<b>556.53</b>	<b>795.58</b>	<b>192.91</b>	<b>5,818.94</b>

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Thus, approximately 67% of PG&E’s current natural gas transmission system was installed prior to federal regulations taking effect in 1970. This compares to a nationwide average figure of about 61%. Federal pipeline safety laws did not require newly installed gas transmission lines to be piggable until 1994. See 49 C.F.R. § 192.150. More than 83% of PG&E’s existing transmission system was installed before 1990. This compares with an industry average of approximately 80%.

Approximately 70% of PG&E’s transmission lines run through Class 1 and Class 2 locations – generally described as less populated areas. Figure 1A-6.3 below depicts the distribution of PG&E transmission miles according to class location:

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**TABLE 3B-3  
PACIFIC GAS AND ELECTRIC COMPANY  
MILES BY CLASS LOCATION**

Miles of Gas Transmission Pipelines at year end 2009, as reported in PHMSA F7100.2-1. Miles by pipe by Class Location.<sup>(a)</sup>

<b>Line No.</b>	<b>Class 1</b>	<b>Class 2</b>	<b>Class 3</b>	<b>Class 4</b>	<b>Total</b>
1 Transmission	3,484.86	583.91	1,704.47	3.71	5,776.96
2 Gas Gathering	41.93	0.00	0.05	0.00	41.98
3 <b>Total</b>	<b>3,526.79</b>	<b>583.91</b>	<b>1,704.52</b>	<b>3.71</b>	<b>5,818.94</b>

<sup>(a)</sup> Class 3 and class 4 locations are highly populated areas as defined in 49 CFR § 192.5. "A class location unit is defined as an area that extends 660 feet on either side of the centerline of a continuous 1-mile length of pipeline." Class 3 is a class location unit containing 46 or more buildings intended for human occupancy. Class 4 is any class location unit where buildings of 4 or more stories above ground are prevalent.

4           As this overview of PG&E's gas transmission system illustrates, PG&E's  
5           system is large, long-standing, and diverse. The history of PG&E's  
6           expansion over the last century illustrates its incredible growth in the middle  
7           part of the last century to serve California's ever-increasing need for natural  
8           gas. PG&E's transmission system has evolved from one reliant entirely on  
9           intrastate gas sources to one that receives almost all of its gas from  
10          interstate sources and transports it throughout a large part of California.  
11          PG&E's pipeline construction, maintenance, and operation activities span a  
12          long period of time. Its pipelines are diverse in terms of their sizes, age, and  
13          characteristics. These considerations influence how PG&E has historically  
14          used gas pipeline records, as discussed further below.

1 **CHAPTER 3C**  
2 **HOW PG&E HAS HISTORICALLY USED GAS PIPELINE RECORDS**

3 **1. Records Relating to Reconditioned Pipe**

4 Violation 23 in the Felts Supplement alleges PG&E failed to maintain  
5 records to track the reuse of reconditioned pipe. It alleges that these  
6 practices violated Section 451 (1954 to 2010) and PG&E’s internal policies  
7 (1994 to 2010). The allegations rest on a series of claims, many of which  
8 lack foundation: (1) the reconditioned pipe in PG&E’s system “may not be  
9 satisfactory for continued service;”<sup>6</sup> (2) PG&E had a tracking system for  
10 salvaged and reused pipe through its accounting records, but “at some time  
11 in the past, PG&E apparently lost track of these records;”<sup>7</sup> and (3) in 1979,  
12 in what appears to be an intentional effort to eliminate records that show the  
13 use of salvaged pipe,” PG&E modified its mapping standards.<sup>8</sup>

14 As explained below, the reuse of reconditioned pipe is not new to  
15 PG&E, the Commission, or the gas industry. PG&E long maintained  
16 practices for using reconditioned pipe, including practices that take into  
17 account the reuse of pipe with known manufacturing threats. Its practices  
18 were consistent with the Commission’s past understandings and industry  
19 practices. While PG&E did not in the past capture data identifying  
20 reconditioned pipe in the gas transmission system in its databases, industry  
21 standards from the past did not require it to do so or even suggest the  
22 practice. Today, PG&E gathers reconditioned and reused pipe data through  
23 its MAOP validation efforts. Other actions – such as hydro testing – provide  
24 a further measure of safety.

25 **a. The Use of Salvaged and Reconditioned Pipe is Not New to PG&E, the**  
26 **Commission or the Gas Industry**

27 PG&E’s past practices address the use of reconditioned pipe. In  
28 Standard Practice 520.6-11, Materials and Storages: Handling of Scrap,  
29 effective as of April 15, 1964, PG&E established a procedure for  
30 separating salvageable from scrap pipe. (Standard Practice (SP) 520.6-

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6 Felts Report at 43.

7 Felts Report at 45.

8 Felts Report at 45.

1 11, Materials and Supplies – Handling and Storage of Scrap (April 15,  
2 1964) (Ex. 3-2).) In Standard Practice 522.1-1, Reconditioning of  
3 Reusable Pipe Removed from Service (Plant Account), effective as of  
4 October 1, 1960, the Company set forth billing procedures for  
5 reconditioning and provided that all reconditioning work would be  
6 undertaken at the Decoto Pipe Yard in Union City. (Standard Practice  
7 (SP) 522.1-1 Reconditioning of Resusable Pipe Removed from Service  
8 Plant (Plant Account) (Ex. 3-3).)

9 In a 1988 document entitled “Reconditioned Pipe A.O. Smith Pipe  
10 Analysis and Policy Gas Operations,”<sup>9</sup> PG&E sets forth the process for  
11 reconditioning A.O. Smith Pipe. That process is likely representative of  
12 the processes PG&E used when reconditioning other types of pipe and  
13 consists of ten steps intended “to assure a high level of certainty that the  
14 reconditioned pipe was in excellent condition when reinstalled.” The  
15 steps were arranged in the following sequence:

- 16 1. Pipe was removed from the ground and sent to Decoto Pipe Yard  
17 for reconditioning.
- 18 2. Pipe was heated and all coating was removed.
- 19 3. Pipe was externally sandblasted.
- 20 4. Pipe surface was visually inspected for corrosion and pitting.
- 21 5. Longitudinal seams were visually inspected inside and outside.
- 22 6. Sections of pipe were removed and discarded if they contained  
23 dents, excessive pitting, corrosion affecting the wall thickness,  
24 defects in the longitudinal seam, or any other unsafe condition.
- 25 7. Oxyacetylene girth welds were removed and pipe ends were  
26 rebeveled.
- 27 8. Bell ends were removed and pipe ends were rebeveled.
- 28 9. Pipe was wrapped.
- 29 10. Pipe was placed in stock for future use.

30 Reconditioning and reusing pipe has been an accepted practice  
31 within the gas industry and among regulators. It was a common practice  
32 throughout the industry at least through the 1960s. “Reusing pipe is an

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<sup>9</sup> Reconditioned Pipe A.O. Smith Pipe Analysis and Policy Gas Operations (1988)  
(Ex. 3-4).

1 acceptable practice as long as the salvaged pipe is inspected and tested  
2 as necessary to confirm the integrity of the pipe for reuse within the  
3 design requirements for the new installation.”<sup>10</sup> As late as 1971, the  
4 Minneapolis Gas Company sought clarification from the OPS regarding  
5 the use of reconditioned pipe under Section 192.63.<sup>11</sup> The company  
6 explained its practice for reconditioning pipe and asked: “Is it  
7 permissible to salvage pipe and fittings when the original markings or  
8 purchase specifications are not available?” In responding, the OPS  
9 acting director did not even suggest that the use of reconditioned pipe  
10 was illegal or inappropriate.

11 The Commission staff has also reviewed and approved for filing  
12 numerous past PG&E gas transmission construction projects in which  
13 PG&E advised the Commission prior to construction that it intended to  
14 install reconditioned pipe. The chart below summarizes at least some of  
15 those filings:

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<sup>10</sup> Felts Report at 44.

<sup>11</sup> Letter from Minneapolis Gas Company to OPS Re Reconditioned Pipe (March 19, 1971) (Ex. 3-5).

**TABLE 3C-1  
PACIFIC GAS AND ELECTRIC COMPANY**

<b>Date PG&amp;E Notified Commission</b>	<b>Date Commission Responded</b>	<b>Job Description</b>	<b>Reconditioned Pipe Description</b>	<b>Pressure Test Description</b>
June 25, 1964 <b>12</b>	July 3, 1964 <b>13</b>	Relocation and reconstruction of Line 109 and 132 due to interstate freeway construction	PG&E: "30' O.D. x .375 wall API 5LX Gr. X52 (reconditioned from Main #132)"	"The reconstructed pipelines will be hydrostatically tested. The minimum test pressure will be 600 psi, equal to 1.5 times the maximum design pressure of 400 psi."
June 29, 1965 <b>14</b>	July 22, 1965 <b>15</b>	Proposed construction of 8 mile, 16-inch pipeline extension from feeder Main 301	PG&E: "This pipe was salvaged and reconditioned from Transmission Main #100, originally installed in 1929.  PUC: "Since the pipe material used is salvage and reconditioned pipes from Main No. 100 originally installed in 1929, with 33,000 minimum yield and 80% joint efficiency, the maximum allowable operating pressure under Section 107 of General Order No. 112-A will be 412 psig.	"The new pipeline will be hydrostatically tested. The minimum pressure will be 618 psig, equal to 1.5 times the maximum design pressure of 412."
Unknown	August 6, 1982 <b>16</b>	Installation of 3,664 feet of 24-inch pipe on Line 21 in Petaluma	PUC: "Recondition, Lower and Anchor 10,400 feet of 16 inch Transmission Line 114"	"We have received your letter of June 4, 1982 concerning this project, which involves new construction using water as a test medium."

**12** Letter from John C. Morrissey, PG&E, to Public Utilities Commission (June 25, 1964) (Ex. 3-6).

**13** Letter from Public Utilities Commission to John C. Morrissey, PG&E (July 3, 1964) (Ex. 3-7).

**14** Letter from John C. Morrissey, PG&E to Public Utilities Commission (June 29, 1965) (Ex. 3-8).

**15** Letter from William W. Dunlop, Public Utilities Commission to John C. Morrissey, PG&E (July 22, 1965) (Ex. 3-9).

**16** Letter from John E. Johnson, Public Utilities Commission, to Daniel E. Gibson, PG&E, Regarding Reconditioned, Lower and Anchor 10,400 feet of 16-inch Transmission Line 114 (August 6, 1982) (Ex. 3-10).

1 PG&E does not in all instances know where reconditioned pipe has  
2 been placed in its transmission system. In the building of its Pipeline  
3 Features List (PFL), PG&E has been gathering this information where it  
4 is available. But the fact that an operator does not know where it has  
5 placed reconditioned pipe would come as no surprise to policymakers  
6 from an earlier era. In the years leading up to the initiation of the  
7 proceeding in which the Commission adopted GO 112, the Commission  
8 had circulated to California operators a staff proposal to impose pipeline  
9 safety regulation. The staff proposal included a provision that provided:  
10 “No used pipe or pipe of unknown specification shall be used in a  
11 pipeline which is designed to operate at pressures of 300 psig or  
12 more.”<sup>17</sup> PG&E submitted comments in response, explaining that the  
13 ASA standards set forth “complete and adequate procedures” to qualify  
14 pipe for reuse and contended that, “[w]ith proper inspection, repair and  
15 test, re-use of this material should be permitted.”<sup>18</sup> Subsequently, the  
16 Commission transmitted to the industry a revised staff draft that omitted  
17 the language that would have prohibited the use of reconditioned pipe or  
18 pipe of unknown specification. When, in December 1960, the  
19 Commission adopted GO 112, it substantially adopted the ASME  
20 standards governing the use of reconditioned pipe.<sup>19</sup>

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<sup>17</sup> Letter from California Public Utilities Commission to Natural Gas Utilities and Interested Parties, with the enclosed Proposed Rules Governing Design, Construction, Testing, Maintenance and Operation of Gas Transmission Pipeline, Section 221 (February 21, 1957) (Ex. 3-11).

<sup>18</sup> Letter from John C. Morrissey, PG&E, to Public Utilities Commission, enclosed with Comments on Staff’s Draft of Proposed Gas Transmission Line General Order, at 3-4 (April 29, 1957) (Ex. 3-12).

<sup>19</sup> ASME B31.8 (1958) included a provision sanctioning the use of salvaged and conditioned pipe. “Removal of a portion of an operating line, and reuse of the pipe in the same line, or at a line operating at the same, or lower pressure, is permitted, subject only to the restrictions of paragraphs A, F and I in 811.27.” Paragraphs A, F and I contained guidelines regarding inspection, surface defects and hydrostatic testing. To this day, ASME B31.8 Section 817 provides for the reuse of properly reconditioned pipe.

1           **b. CPSD Presents No Evidence to Support its Allegation that the**  
2           **Reconditioned Pipe in PG&E’s System is Unsatisfactory for**  
3           **Continued Use**

4           In her report, Ms. Felts alleges that in “the process of reviewing  
5           PG&E records it has become apparent that PG&E has salvaged and  
6           reused transmission pipe now operating in its system that may not be  
7           satisfactory for continued service.”<sup>20</sup> In making this allegation, she cites  
8           to authorization, accounting, transfer and shipping documentation rather  
9           than the sort of documents that would be used to maintain detailed  
10          material specification.<sup>21</sup> The cited documents cannot support the  
11          conclusion that pipe is unsatisfactory.

12          To the extent that Ms. Felts has identified weld reports showing the  
13          reconditioning of pipe, she has assumed that such pipe actually was  
14          reused (as opposed to only being sent to the yard for reconditioning). It  
15          also does not specify the date the pipe was installed. Pipe installed  
16          after July 1961 (if not earlier) would have been hydro tested to a  
17          pressure at least 1.25 times its design strength. Ms. Felts has also not  
18          addressed information PG&E has produced showing the process the  
19          Company used before reusing pipe. Additionally, based on its current  
20          understanding of its past practices and industry standards, PG&E  
21          believes that as part of the reconditioning process, it removed all field-  
22          made girth welds.

23           **c. Felts’ Allegation that PG&E Lost Records Pertaining to Salvaged Pipe**  
24           **is Unsubstantiated**

25          Ms. Felts also maintained that PG&E lost records indicating the  
26          location of where it had reconditioned pipe. PG&E has not, as best it is  
27          aware, lost records about reused pipe. Where older records of this kind  
28          are lacking, it more likely is because they were not created. Many job  
29          files, however, include records that sometimes demonstrate the use of  
30          reconditioned pipe. These records include job estimates, shipping  
31          notices and journal entries or vouchers.

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<sup>20</sup> Felts Report at 43.

<sup>21</sup> PG&E’s Response to Records OII Data Request 4-Q22.



1           **d. CPSD Misreads PG&E’s Standard – PG&E Did Not Intentionally**  
2           **Eliminate Records Regarding the Use of Reconditioned and**  
3           **Reused Pipe**

4           Ms. Felts further alleges that PG&E deliberately destroyed a  
5           tracking system it maintained for reconditioned pipe: “In 1979, in what  
6           appears to be an intentional effort to eliminate records that show the use  
7           of salvaged pipes, PG&E’s drafting instructions in Mapping Standards  
8           410.21-1, section II.3, state ‘salvaged and abandoned mains – to be  
9           removed from plat sheets.’”<sup>22</sup> Ms. Felts misunderstands the standard.  
10          Standard 421.21-1 informs the making and maintaining of distribution  
11          plats. It gives direction to erase outdated information and revise plats to  
12          reflect street name changes. The section of the standard that the CPSD  
13          quotes (see above) provides in full: “Salvaged and Abandoned Mains.  
14          To be removed from plat sheets. Consult with supervisory personnel for  
15          local operating procedures. S.P. 463 Abandonment of Gas Mains and  
16          Services.”<sup>23</sup> Information of this kind is removed to avoid confusion. In  
17          many instances, information about abandoned pipe was maintained in  
18          abandoned line books. The section instructs mappers to remove  
19          abandoned and disused mains from distribution plat sheets. It does not,  
20          contrary to Ms. Felts’ allegations, instruct mappers to deliberately  
21          destroy records showing the use of reconditioned and reused pipe in  
22          active pipelines.

23          **2. Construction Records (Job Files)**

24          The Felts Report alleges (Violations 16) that from 1987 to 2010, PG&E’s  
25          job files were missing and disorganized, in violation of Section 451, ASME  
26          B31.8, and PG&E’s records retention policies.<sup>24</sup> Her report further alleges  
27          violations (dating to the 1930s) because PG&E cannot locate certain post-

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<sup>22</sup> Felts Report at 45.

<sup>23</sup> Standard Practice (SP) 420.21-1: Mapping Standards, Gas Department 1"= 100 Plat Sheets, at Section II.3 (Ex. 3-13).

<sup>24</sup> Felts Supplement at 12.

1 installation pressure test records.<sup>25</sup> The CPSP asserts violations relating to  
2 PG&E's management of its job files. The Duller/North Supplement charges  
3 (Violation II.A.1) that from 1955 to 2010, PG&E lacked traceable, verifiable  
4 and complete pipeline records in violation of ASME B31.8, Section 451, Part  
5 192.709, and GO 112, 112A, and 112B Section 107.<sup>26</sup>

6 The allegations are wide-ranging and tied only loosely to stated  
7 violations.<sup>27</sup> Nonetheless, the Felts and Duller/North reports appear to  
8 place at issue: (a) missing strength test pressure records; (b) the process  
9 by which PG&E numbers pipeline construction jobs; and (c) the existence of  
10 duplicate and decentralized job folders and poor retrieval process. Each  
11 subject is address below.

12 **a. Strength Test Pressure Records**

13 The Felts Supplement alleges (Violation 18) that PG&E is missing  
14 post-installation strength test pressure records. PG&E's efforts to locate  
15 strength test records have been the subject of numerous filings in the  
16 OIR 11-02-019 proceeding. (E.g., March 15, 2011 filing, March 21,  
17 2011 filing, May 10, 2011 filing, June 10, 2011 filing, August 26, 2011  
18 filing, January 13, 2012 filing, and May 14, 2012 filing.) The detailed  
19 contents of those filings do not need to be restated here. PG&E has  
20 taken unprecedented steps to validate the MAOP of pipelines, including  
21 the strength testing of 152 miles of pipeline for segments for which the  
22 records indicate the segments have common characteristics with the  
23 records for the ruptured segment of Line 132. Southern California Gas  
24 Company, San Diego Gas and Electric Company and Southwest Gas  
25 Company have determined that they too lack or are missing strength  
26 test pressure reports for portions of their lines and are taking actions to  
27 address those records gaps. As Mr. De Leon (Chapter 1.A), Mr. Howe

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<sup>25</sup> The violation also asserts that PG&E is missing design basis records and references Section 4.3 of the Felts Report for supporting analysis. But except to mention design basis records, Section 4.3 focuses exclusively on post-installation strength test pressure records. Accordingly, PG&E's response does as well.

<sup>26</sup> Duller/North Supplement at 2.

<sup>27</sup> In support of Violation I.A.1 the Duller/North Report cites generally to Chapters 6 and 7 of their testimony. Together, Chapters 6 and 7 run more than 80 pages in length.

1 (Chapter 1.B), and Mr. Zurcher (Chapter 3.A) explain, the problem of  
2 missing or incomplete pipeline records, particularly for vintage pipe, is  
3 not confined to California operators.<sup>28</sup>

4 **b. The Job Numbering Process**

5 The Duller/North Report alleges that PG&E's job numbering  
6 processes led to significant records gaps and data quality issues.<sup>29</sup>

7 The Duller/North Report points to job numbering in PG&E's ECTS  
8 system. ECTS is a document repository PG&E has used to support its  
9 MAOP Validation efforts. The way job numbers appear in ECTS does  
10 not reflect PG&E's historic job numbering system, or indicate PG&E's  
11 future records management direction. ECTS data is being continuously  
12 uploaded to Documentum. Documentum (not ECTS) will be the  
13 forward-looking repository for job file information.

14 The weakness of the inferences Duller/North draw from the ECTS  
15 records shows itself through examples. In the Duller/North report at  
16 Table 6-13, they identify "alpha text only" as a job numbering system. It  
17 was not a historic job numbering system, but a data field introduced in  
18 the course of the MAOP validation effort. Similarly, an alpha prefix of  
19 "P00427" identifies a work break down structure (WBS) number. WBS  
20 was a project management control process that PG&E retained to  
21 manage large projects.

22 Even where the Duller/North Report zeros in on PG&E's historic job  
23 numbers, it misapprehends how job numbers were created. Many jobs  
24 begin not as full-fledged construction projects but as smaller work  
25 orders. PG&E's divisions historically have used a four-digit system for  
26 numbered work orders of the kind that reflect smaller jobs. That  
27 numbering system is very different from the one PG&E uses when

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<sup>28</sup> The date range of violations is too broad in any event. Ms. Felts asserts that PG&E lacks post-installation pressure test records dating to the 1930s. PG&E cannot possibly be "missing" a post-installation pressure test from the 1930s or 1940s. The means to conduct post-installation hydrostatic pressure tests was not widely available in the pipeline industry until the early 1950s. (Shires, T. M. et al, *Development of the B31.8 Code and Federal Pipeline Safety Regulations Implications for Today's Natural Gas Pipeline System*, Volume 1, GRI-98/0367.1, Appendix E, at E-9 (December 1998) (Ex. 3-14).

<sup>29</sup> E.g., Duller/North Report at Sections 6.4.2 and 6.4.9.

1 initiating larger pipeline jobs. The latter system is chronological. A five-  
2 digit job number, for instance, would indicate an older job – one  
3 conducted in the 1930s. A longer number generally reflected a job  
4 constructed closer in time to the present day.

5 Another example of how historic job numbers originated in PG&E’s  
6 system was through acquisition of facilities from another utility. The MIR  
7 or Main Installation Record found on some job files is a prefix for 3 and 4  
8 digit numbers for old Coast Counties Gas and Electric facilities. These  
9 are different from other types of job numbers reflecting their  
10 different origin.

11 Both the Duller/North and Felts reports identify sequence gaps in job  
12 numbering, and infer that these gaps evidence a “missing” gas  
13 transmission job file.<sup>30</sup> The inference lacks support. PG&E issues job  
14 numbers across the enterprise, which includes jobs for Gas Distribution,  
15 Hydro, Electric Distribution and Transmission, vehicle purchases, as  
16 well as all lines of business. Gaps between one gas transmission job  
17 number and another may reflect intervening gas distribution, electric,  
18 hydro and other projects – not necessarily missing gas  
19 transmission jobs.

20 The Duller/North Report additionally alleges that PG&E’s treatment  
21 of any variation in a job number as a unique job number creates data  
22 quality problems that cascade throughout PG&E’s information systems.  
23 But Dr. Duller and Ms. North confuse historic job numbering conventions  
24 with the recent activities involved in the processing of job file documents  
25 as part of the MAOP Validation efforts. These are transitory post-  
26 September 2010 developments intended to support the MAOP  
27 Validation effort, and do not represent “data quality problems.”

28 While the explanations above address the CPSD’s  
29 misunderstandings of PG&E’s job numbering schemes, we  
30 acknowledge that there are gaps in our job records, and are addressing  
31 those gaps through the MAOP Validation project.

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<sup>30</sup> Duller/North Report, Table 6-14, at 6-59; Felts Report at 32.

1           **c. Duplicate and Decentralized Job Files and PG&E’s Retrieval Process**

2           Dr. Duller and Ms. North see in the existence of duplicate and  
3           dispersed job folders poor records management practices.<sup>31</sup>

4           Specifically, the Duller/North Report asserts that PG&E did not maintain  
5           a comprehensive index or single master source of information, and that  
6           information was poorly catalogued.<sup>32</sup>

7           PG&E has historically performed gas transmission pipeline  
8           construction work in field locations across a 70,000 square mile service  
9           territory. Construction records have been paper-based. Larger  
10          construction projects require project engineers, project managers, field  
11          engineers, estimators, mappers, and construction foreman to use and  
12          retain copies of these paper records. Each of these individuals may  
13          reside in different physical locations hundreds of miles from one  
14          another. Understandably, their files were dispersed and at least partly  
15          duplicated one another. After jobs were completed, engineers in San  
16          Francisco (later Walnut Creek) needed records of the job, as did local  
17          divisions or districts, leading to further duplication and decentralization.  
18          PG&E acknowledges that even though there were procedures in place,  
19          they were not always consistently followed. The fact that copies of job  
20          file documents were located in field offices is not only understandable,  
21          but makes sense, given limited technology, emerging purpose needs,  
22          functional distinctions between divisions and districts, and the size of  
23          PG&E’s service territory.

24          PG&E also acknowledges that prior to San Bruno, it did not have a  
25          system-wide index of all its pipeline job files. What it did have were  
26          distribution and transmission plat sheets that served as graphically  
27          displayed indices. They served the operational and maintenance needs  
28          of those who used them on a day-to-day basis in the field. In addition,  
29          SAP and GIS both provide significant job file information, but neither  
30          system was comprehensive. (PG&E’s Response to Records OII  
31          Request 25-Q3 (Ex. 3-15).) Other tools existed, such as Docutrak and  
32          EDMS, but they too were not comprehensive. As a result, PG&E relied

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<sup>31</sup> E.g., Duller/North Report at 6-45.

<sup>32</sup> E.g., Duller/North Report at 6-79.

1 heavily on a sometimes cumbersome retrieval process that involved the  
2 potential of several searches for relevant documents.

3 The inefficiencies in the job files retrieval process were the by-  
4 product of a paper-based and decentralized records management  
5 structure that had served the Company well in an earlier era but has  
6 outlived its usefulness. PG&E's GTAM initiative (discussed in Chapter  
7 1.D above) will take advantage of information management  
8 improvements to allow PG&E to create and maintain a centralized data  
9 management system that will allow for the more efficient retrieval of  
10 source documents relating to PG&E's pipeline system.

### 11 3. **Weld Information/Failure Reports**

12 The Felts Supplement alleges two Section 451 violations relating to weld  
13 failure records: (1) 1963 weld failure – no Failure Report (Violation 27); and  
14 (2) 1988 weld failure – no Failure Report (Violation 26). In the case of the  
15 violations, she maintains that each violation runs from the date of the  
16 missing report through 2010. For the analysis supporting these alleged  
17 violations, Ms. Felts points to Section 4.4 of her report.

18 Section 4.4 of the Felts Report does not address either a 1963 or 1988  
19 weld failure. Except for a brief reference contained in Footnote 154, Section  
20 4.4 does not address the topic of weld failure reports at all. Instead it  
21 addresses "weld maps and weld inspection reports."<sup>33</sup> The brief reference  
22 to weld failure reports in Footnote 154 states:

23 An additional source of weld quality data is technical  
24 reports resulting from metallurgical analysis of pipe welds  
25 that are either suspect or that failed. PG&E performs  
26 these analyses at its San Ramon ATS facility and also  
27 contracts out to various labs. The records experts for this  
28 OII, Paul Duller and Alison North estimate that  
29 approximately 17% (13,228) of the analytical  
30 investigation reports are missing.

31 In her Supplement, Ms. Felts added the following language to footnote 154:

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<sup>33</sup> Felts Report at 35.

1 During the OII, PG&E was repeatedly asked to produce  
2 the technical reports for Line 132 weld failure that  
3 occurred in 1963 and 1988 (OII\_DR\_041-Q05). PG&E  
4 has not produced the report on the 1963 weld failure.  
5 However, on March 7, 2012, nine months after the issue  
6 arose, PG&E produced a cover letter reporting the results  
7 of the analysis of the 1988 longitudinal weld failure, but  
8 still failed to produce the report referenced in the letter.  
9 (OII\_DR\_041-Q05Supp01Atch01).”<sup>34</sup>

10 Though not entirely clear, Violations 26 and 27 appear to be supported by  
11 footnote 154 (as supplemented with two additional sentences) and appear to  
12 reference missing metallurgical reports prepared either by a consultant or  
13 PG&E’s ATS organization.

14 **a. The 1963 Incident**

15 On January 2, 1963, there was a fire and explosion on Line 109  
16 near the intersection of Alemany Boulevard and Nevada Street in San  
17 Francisco. A sample of the broken pipe and weld joint was removed for  
18 analysis. We believe that at one time, it maintained a metallurgical  
19 report relating to the 1963 incident. As indicated in a letter dated as of  
20 March 13, 1963 from PG&E to the Commission (P7-7094 (Ex. 3-16)),  
21 We understand that a third-party metallurgist was retained to produce a  
22 report on the quality and probable causes of the fracture of the  
23 circumferential weld at issue in the 1963 incident in San Francisco. We  
24 believe this is because the letter indicates the report was being  
25 transmitted to Commission staff. We have not located a copy of the  
26 transmitted report (which at this point would be almost 50 years old).  
27 Apparently, Commission staff has been unable to locate it in its files  
28 either. We have located and provided in this proceeding a significant  
29 amount of detailed correspondence between the Company and the  
30 Commission regarding the 1963 incident. (Ex. 3-16.) Without question,  
31 PG&E would also like to locate the consultant’s metallurgical report it  
32 previously provided to the Commission. However, absent an allegation

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<sup>34</sup> Felts Supplement at 17 (italics removed).

1 that a report of this kind must be maintained for the life of the facility  
2 (CPSD makes no such allegation), the failure to retain a report the  
3 Company shared with the Commission fifty years ago does not rise to  
4 the level of a Section 451 violation.

5 **b. The 1988 Weld Inspection Report**

6 Ms. Felts represents that PG&E produced “a cover letter reporting  
7 the results of the analysis of the 1988 longitudinal weld failure, but still  
8 failed to produce the report referenced in the letter.”<sup>35</sup> In fact, PG&E  
9 produced three memoranda, two of which reference attached  
10 documents. As explained below, the assumption that Ms. Felts seems  
11 to draw from this correspondence – an ATS report is missing –  
12 illustrates the hazards of trying to assert a violation based on cold record  
13 review of events that occurred a long time ago.

14 The first of the three memoranda PG&E produced as part of its  
15 supplemental response to Data Request 41, Question 5, was the  
16 memoranda dated December 1, 1988.<sup>36</sup> It is addressed to Golden  
17 Gate (one of PG&E’s regional offices) from Gas System Design. Gas  
18 System Design writes to Golden Gate Region:

19 “I have received the Material and/or Equipment –  
20 Problem or Failure Report that you prepared describing  
21 the failure of the longitudinal welding on 30-inch steel  
22 pipe. This report has been assigned to [name redacted]  
23 of the Pipeline System Engineering of Gas System  
24 Design Department. The evaluation for this report is  
25 expected to be completed by April 1989.”

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<sup>35</sup> Felts Supplement at 17.

<sup>36</sup> Letter from Gas System Design to Golden Gate (December 1, 1988) (PG&E’s Supplemental Response to Records OII Data Request 41-Q5) (Ex. 3-17).




FIGURE 3C-1  
PACIFIC GAS AND ELECTRIC COMPANY

Confidential-Provided Pursuant to  
Public Utilities Code Section 563

GasTransmissionSystemRecords01\_DR\_CFCUC\_041-Q05Supp01Atch01

Date: December 1, 1988 File #: 460.21  
Re: GOLDEN GATE  
From: GAS SYSTEM DESIGN  
Subject: Failure of Longitudinal Welding on  
30-Inch Steel Pipe

 [REDACTED]  
I have received the Material and/or Equipment - Problem or Failure Report that you prepared describing the failure of the longitudinal welding on 30-inch steel pipe. This report has been assigned to [REDACTED] of the Pipe Line System Engineering of Gas System Design Department. The evaluation for this report is expected to be completed by April 1989.

If you have any questions concerning this report, please contact me on Ext. [REDACTED]

[REDACTED]  
[REDACTED] : cm  
cc: [REDACTED] (w/attachment)  
RON MORRIS

- 1 The second memorandum is dated March 1, 1989.<sup>37</sup> It is
- 2 addressed to Gas System Design from Technical and Ecological
- 3 Services (then known as T&ES, a predecessor organization to the
- 4 Applied Technology Services (or ATS)) organization referenced in Felts'

<sup>37</sup> Letter to Gas System Design (March 1, 1989) (Ex. 3-17).

1 footnote 154. The first paragraph of the March 1, 1989 memorandum  
2 references an attachment. It reads:

3 "A section of the 30" Bunker Hill transmission line (132)  
4 was removed for failure analysis because of a pinhole  
5 leak in the longitudinal seam weld (*see attached*  
6 *materials failure report*). X-ray, dye, penetrant, and  
7 magnetic particle inspections were performed on the  
8 submitted section, but these do not locate the leak. The  
9 X-ray and subsequent metallographic examination  
10 identified several weld shrinkage cracks but they did not  
11 extend through wall. The cracks are pre-service defects,  
12 i.e., they are from the original manufacturing of the pipe  
13 joint." (Italics added.)

FIGURE 3C-2  
PACIFIC GAS AND ELECTRIC COMPANY

Confidential- Provided Pursuant to  
Public Utilities Code Section 583

GasTransmissionSystemRecordsOII\_DR\_CPUC\_041-Q05Supp01Atch01

Memorandum

Date: March 1, 1989 Ref: 4152  
To: GAS SYSTEM DESIGN  
From: TECHNICAL AND ECOLOGICAL SERVICES  
Subject: Bunker Hill 30" Transmission Line Failure



A section of the 30" Bunker Hill transmission line (132) was removed for failure analysis because of a pinhole leak in the longitudinal seam weld (see attached materials failure report). X-ray, dye penetrant, and magnetic particle inspections were performed on the submitted section, but these did not locate the leak. The X-ray and subsequent metallographic examination identified several weld shrinkage cracks, but they did not extend through wall. The cracks are pre-service defects, i.e., they are from the original manufacturing of the pipe joint.

Overall, the X-ray inspection showed the weld to be of low quality, containing shrinkage cracks and voids, lack of fusion, and inclusions. Although the actual leak could not be found, it is likely that it was related to one of the weld defects. With the leak removed, the remaining pipe should be fully operational again.

If you have any further questions, please contact myself or [redacted] at [redacted] or [redacted].

033102/kar29  
xc: RDKerr/CBSScott  
Attachment

02/28 (rev 148)

1 The third memorandum is dated March 20, 1989.<sup>38</sup> This is a  
2 memorandum to the Golden Gate Region from Gas System Design. It  
3 provides in substance:

<sup>38</sup> Letter from Gas System Design to Golden Gate Region (March 20, 1989)  
(Ex. 3-17).

1  
2  
3  
4  
5  
6

“Thank you for bringing to our attention the problem with the longitudinal weld on the 30-inch steel pipe. The Gas System Design Department has finished processing the Material and/or Equipment – Problem or Failure Report you submitted (GSD received date 11/28/88). A copy of the completed report is attached.”

**FIGURE 3C-3  
PACIFIC GAS AND ELECTRIC COMPANY**

Confidential- Provided Pursuant to  
Public Utilities Code Section 583

GasTransmissionSystemRecordsOH\_DR\_CPUC\_041-Q05Supp01Atch01

**Memorandum**

Date: March 20, 1989  
To: GOLDEN GATE REGION  
From: GAS SYSTEM DESIGN  
Subject: Failure of Longitudinal Weld on  
30-Inch Steel Pipe

PG&E

Thank you for bringing to our attention the problem with the longitudinal weld on the 30-inch steel pipe. The Gas System Design Department has finished processing the Material and/or Equipment – Problem or Failure Report you submitted (GSD received date 11/28/88). A copy of the completed report is attached.

If you have any questions concerning this report, please contact me on Ext. [REDACTED]

cc: [REDACTED]  
[REDACTED]  
[REDACTED]  
[REDACTED]

Attachment: [REDACTED]

460.21

4/20/89

1 Among the documents PG&E provided as part of its Supplemental  
2 Response to Records OII Data Request 41, Question 5, was a  
3 document captioned: "Material and/or Equipment – Problem or Failure  
4 Report."<sup>39</sup> The top portion of the document bears a banner indicating it  
5 was "TO BE COMPLETED BY FOREMAN AND/OR LOCAL  
6 ENGINEERING STAFF." That portion is completed in hand and dated  
7 October 27, 1988. The bottom portion of the document bears the  
8 banner: "FOR USE BY GAS SYSTEM DESIGN DEPARTMENT." It  
9 bears a stamp reflecting it was received by Gas System Design on  
10 November 28, 1988, and assigned to the same person referenced in  
11 Gas System Design's initial December 1, 1988 memorandum to Golden  
12 Gate Region. In the section identified as "FOR USE BY GAS SYSTEM  
13 DESIGN DEPARTMENT" is a row labeled: "Evaluation, comments and  
14 actions by Gas System Design." In that row, there appears a  
15 handwritten note: "Failed section of pipe was inspected. See the  
16 attached T & ES Letter dated March 1, 1989." The reference to the "T &  
17 ES Letter dated March 1, 1989" appears to be a reference to the second  
18 memorandum described above that was prepared by Technical and  
19 Ecological Services. This bottom portion of the Material and/or  
20 Equipment – Problem or Failure Report" is dated approved as of "March  
21 20, 1989," suggesting that this is the same document that was attached  
22 to the third memorandum described above.

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<sup>39</sup> Material and/or Equipment – Problem or Failure Report (March 20, 1989)  
(Ex. 3-17).

**FIGURE 3C-1  
PACIFIC GAS AND ELECTRIC COMPANY**

Confidential- Provided Pursuant to  
Public Utilities Code Section 583

GasTransmissionSystemRecordsOil\_DR\_CPUC\_041-Q05Supp01Atch01

75-229  
REV. 10/85

S.P. 460.21-7  
Attachment 1

**MATERIAL AND/OR EQUIPMENT - PROBLEM OR FAILURE REPORT**

**NOTE:** Do not use this form for reporting failures or accidents which result in death, injury, and/or property damage. Also, this form should not be used for reporting corrosion leaks in pipe, or replacement due to normal wear.

TO BE COMPLETED BY FOREMAN AND/OR LOCAL ENGINEERING STAFF

See Attachment 2 of S.P.460.21-7 for Instructions

1. Failed material or equipment LONGITUDINAL WELD ON 20" T.L. 132
  2. Location (address) where failure occurred BANKER HILL DRIVE SAN MATEO City, Co. SAN MATEO
  3. Material or equipment details and description of problem or failure  
A PINHOLE LEAK WAS FOUND ON THE LONGITUDINAL WELD ON 20" T.L. 132.
  4. Service information: Date installed 1948 Other information GM 98015
  5. Disposition of failed material Delivered to [redacted] G.A.R. Gas Manager on 11-9-88.
  6. Person to contact for information [redacted] Telephone [redacted]
  7. Reported by: [redacted] Location Promisla Region G.G. Date 10-27-88
  8. Noted by Regional office: By [redacted] Date 881116
- SEND ORIGINAL TO MANAGER GAS SYSTEM DESIGN DEPARTMENT - ROOM 2667, 77 BEALE STREET
- FOR USE BY GAS SYSTEM DESIGN DEPARTMENT      DATE RECEIVED
- |                   |          |
|-------------------|----------|
| GAS SYSTEM DESIGN |          |
| PCH               | FRJ Date |
| JRG               | RMB      |
| RCE               | ED       |
| JAC               | CH       |
| SYC               | REMARKS  |
| RFD               | DATE     |
| DCR               | INITIALS |
9. Review assigned to: [redacted] - CRS 11/29/88
10. Copies distributed to: (Gas Dist.)
11. Evaluation, comments and action by Gas System Design:  
FAILED SECTION OF PIPE WAS INSULATED. SEE THE ATTACHED LETTER DATED 3/1/89
12. Evaluation completed by: [redacted] Telephone [redacted] Date 3/15/89
13. Approved by: [redacted] Date 3-20-89

**FEEDBACK\***

14. By: OEA Date 3/20/89 Method Letter

To: \_\_\_\_\_

\* **IMPORTANT:** Feedback must be provided on all Material Problem or Failure Reports, either by letter or copy of completed report. Distribution should be made as outlined in the Guidelines (Supplement to S.P. 460.21-7).

1                    When Ms. Felts refers to "a cover letter reporting the results of the  
2 analysis of the 1988 longitudinal weld failure, but still failed to produce  
3 the report referenced in the letter[,]" it is unclear what report she  
4 believes PG&E failed to produce. Of the two memoranda that reference  
5 a report, the memoranda dated March 1, 1989 appears to reference and

1 attach the material failure report initially prepared by the Golden Gate  
2 Region which reported the leak. “A section of the 30” Bunker Hill  
3 transmission line (132) was removed for failure analysis because of a  
4 pinhole leak in the longitudinal seam weld (see attached materials  
5 failure report).” (Ex. 3-17.) This makes sense because among the  
6 documents that PG&E produced was a version of the Material and/or  
7 Equipment – Problem or Failure Report for the 1988 leak with only the  
8 top part completed.

9 The March 20, 1989 memorandum from Gas System Design to the  
10 Golden Gate Region similarly references the material failure report  
11 prepared by the Golden Gate Region. But this time it states it is  
12 attaching the completed report. Again this is consistent with the  
13 documents PG&E produced. Those documents, as discussed above,  
14 include a Material and/or Equipment – Problem or Failure Report, with  
15 both the top and bottom sections completed.

16 Conceivably, Ms. Felts believes that there is a report that was  
17 prepared by the Technical & Ecological Services group that PG&E has  
18 been unable to produce. But that belief rests on the assumption that the  
19 documents that have been described, taken together or apart, reference  
20 a Technical and Ecological Services report separate from March 1, 1989  
21 memorandum. That assumption is difficult to corroborate these many  
22 years later. An equally (if not more) plausible assumption is that where  
23 the completed version of the Material and/or Equipment – Problem or  
24 Failure Report attaches the “T & ES letter dated March 1, 1989,” it is  
25 attaching the only report that T & ES prepared from its analysis of the  
26 section of 30 inch pipe that failed in 1988. Certainly, there is one other  
27 instance from this era T&ES appeared to provide its report by letter  
28 without any supporting laboratory results or other analysis. (P7-7076.)

29 We regret that we were unable to locate and produce these 1988  
30 leak documents sooner than we did. Even so, we located them. Ms.  
31 Felts’ Violation 27, which asserts PG&E still has not located the  
32 metallurgical report for the 1988 leak, rests on an assumption that more  
33 probably than not is inaccurate. Indeed, Ms. Felts searches for the  
34 existence of a record that likely was never written.

1  
2

## CHAPTER 3D EARTHQUAKE RISKS AND THE GPRP

3

### 1. The Use of Records in Assessing Seismic Risks

4           The Duller/North Supplement charges that, from 1992 to 2010, PG&E  
5 violated ASME B.31.8 and Section 451 because it lacked the “necessary  
6 accurate and readily locatable gas transmission line records” needed to  
7 “precisely identify which of its pipelines were more prone to extensive  
8 damage during some earthquakes and thereby ensure safe pipeline  
9 operation.”<sup>40</sup> For supporting analysis, the Duller/North Supplement refers  
10 to Section 6.7 of the Duller/North Report. Section 6.7 consists of a self-  
11 described “short section that links earthquakes, pipelines and records  
12 management.”<sup>41</sup> The section is indeed short: it amounts to a page and a  
13 half, much of it block quotations from a 1992 FEMA report on earthquake  
14 resistant pipeline construction methods. There is no mention of any facts in  
15 the discussion – just quotations from the FEMA report and broad  
16 conclusory statements.

17           PG&E’s June 20, 2011 filing included an extended discussion of the  
18 efforts PG&E takes to address risks from ground movement, including  
19 earthquakes. (June 20, 2011 filing, Chapter 6C, at 6C-22-24.)<sup>42</sup> PG&E has  
20 long recognized its responsibilities as an operator in a seismically active  
21 territory. Although many of its current efforts post-date the 1989 Loma  
22 Prieta earthquake, PG&E evaluated seismic hazards before then. Only a  
23 few days before Loma Prieta, in fact, PG&E gave a presentation on seismic  
24 hazards that could affect the Bay Area transmission system.<sup>43</sup>

25           After the earthquake, PG&E’s Geosciences Department performed a  
26 comprehensive seismic review of the pipeline system.<sup>44</sup> Between  
27 approximately 1990 and 1992, PG&E added liquefaction and landslide

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<sup>40</sup> Duller/North Supplement at 5 (footnote omitted).

<sup>41</sup> Duller/North Report at 6-91.

<sup>42</sup> PG&E incorporates this section of Chapter 6C from the June 20, 2011 filing by reference.

<sup>43</sup> Golden Gate Region Gas Department, Seismic Study of Gas Transmission Lines: Project Review Meeting Phase 1 Results (October 13, 1989) (Ex. 3-18).

<sup>44</sup> PG&E, Program for Reducing Earthquake Vulnerability of Gas and Electric Systems by the Year 2000 (December 1990) (“1990 Program”) (Ex. 3-19).



1 hazards to its gas transmission corridor maps for its three peninsula  
2 transmission lines. It relocated piping under fault crossings to avoid  
3 ruptures in the event of future earthquakes and aligned the piping so that it  
4 would experience less stress during ground movements. Additionally,  
5 PG&E used piping materials and welding techniques that could withstand  
6 greater stress levels and, in certain instances, installed shut-off and one-  
7 way valves.

8 In about 2005, PG&E launched system-wide digital geo-hazard maps.<sup>45</sup>  
9 Through the use of extensive seismic information provided by the U.S.  
10 Geological Services in combination with other data, the Geosciences  
11 Department was able to develop a detailed and specific fault crossing list for  
12 all of the company's pipe segments. In 2006, PG&E adopted its Gas  
13 Transmission Earthquake Plan and Response Procedure, RMI-04. (P3-  
14 27406.)

15 More recently, PG&E has extended its Dynamic Automated Seismic  
16 Hazard (DASH) program to gas transmission. The Geosciences  
17 Department uses DASH to run detailed scenarios involving eight possible  
18 Bay Area earthquakes and generate annual reports. Each scenario includes  
19 a "Shake Map" and list of high risk gas pipes and stations associated with  
20 that potential earthquake.<sup>46</sup>

21 The Geosciences Department quantifies the relative priorities of the  
22 different scenarios using a value algorithm that factors in fault crossing,  
23 liquefaction, slope stability, pipe age, HCA designations, and the Shake  
24 Map. The DASH program also automatically calculates the prioritization for  
25 pipeline segments after an actual earthquake and electronically sends the  
26 information to emergency response personnel. That report specifies what  
27 segments have the highest response priority and thus helps personnel in the  
28 field prioritize their investigations.

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<sup>45</sup> Letter from Christopher S. Hitchcock, William Lettis & Associates, Inc., to Stuart Nishenko Regarding Transmittal and Documentation of Revised GIS Hazard Layers (Liquefaction and Landslide Hazards) for CGT Gas Transmission System (November 9, 2005) (Ex. 3-20).

<sup>46</sup> Gas Transmission DASH Report Scenario Event, M7.0 – Scenario – Rodgers Creek (June 6, 2012).

1           The gas system’s greatest vulnerability in an earthquake is the potential  
2 for extensive leakage in the portions of the distribution system that are in  
3 liquefaction zones and that are relatively weak because of brittle pipe, weak  
4 pipe joints or girth welds, or corroded pipe. (Ex. 3-19.) In the 1989 Loma  
5 Prieta Earthquake, PG&E had three transmission line failures (compared to  
6 over 80 transmission line failures in the 1971 San Fernando earthquake  
7 mentioned in the Duller/North Report).<sup>47</sup> The more extensive damage  
8 during the Loma Prieta earthquake was to the cast iron distribution system  
9 in the Marina District of San Francisco. The least resistant elements of the  
10 gas system were the focus of the Company’s GPRP program, which was  
11 implemented in 1985 to replace aging pipe throughout PG&E’s system.

12           Section 6.7 of the Duller/North Report does not address the sufficiency  
13 of any of these efforts by PG&E to manage the risks associated with ground  
14 movement, including earthquakes. Nor does it identify how any of the data  
15 analysis and management tools developed by PG&E as part of these efforts  
16 are in any way deficient. Nor does it identify the specific regulations that  
17 PG&E violated: the Duller/North Report points generally to Section 451 and  
18 the ASME standards, but fails to cite a single provision governing ground  
19 movement preparedness that PG&E failed to meet.

20           The Duller/North Report references a 1992 FEMA study, but that study  
21 highlighted the experience in the 1971 San Fernando Valley earthquake in  
22 which the most serious pipeline damage was to an oxyacetylene welded  
23 pipeline installed about 1930. Line 132 is not pipe installed in this era and  
24 its girth welds are not of this type.

## 25       **2. Gas Pipeline Replacement Program**

26           The CPSD also alleges PG&E violated Section 451 in carrying out its  
27 Gas Pipeline Replacement Program (GPRP). In short, the CPSD alleges  
28 that PG&E excluded Line 132 from the GPRP by using the wrong year as  
29 the upper limit for its GPRP – 1947 instead of 1948 – when assessing the  
30 excavation threat to gas transmission pipelines. The CPSD concludes: “If  
31 Line 132 had been included in this program and replaced the San Bruno

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<sup>47</sup> Donald Ballantyne, *The ShakeOut Scenario* (Supplemental Study prepared for the U.S. Geological Survey and California Geological Survey), at 1 (May 2008) (Ex. 3-21).

1 rupture and fire could have been avoided.”<sup>48</sup> However, this claim is without  
2 merit, as Segment 180 and sections of Line 132 built in 1948 did not meet  
3 other criteria in the GPRP, and would not have been replaced regardless of  
4 the cutoff date.

5 PG&E launched the GPRP in 1985. The purpose of the program (as it  
6 related to transmission) was to replace transmission pipe that were welded  
7 using oxyacetylene (Oxy-butt), bell-bell chill ring (BBCR), or bell and spigot  
8 (BLSP) girth welds. These girth welds were particularly susceptible to  
9 ground movement-related failure (e.g., earthquake, landslide). A report  
10 prepared by a former employee (and cited by the CPSD) indicates that the  
11 scope of GPRP was limited to replacing transmission pipe installed in 1947  
12 and prior years.<sup>49</sup>

13 Despite the fact that Line 132, Segment 180, was constructed in 1956, it  
14 would not have been a candidate for replacement under the GPRP. The  
15 girth welds on Segment 180 were constructed using the beveled-edge  
16 configuration, and the weld was made using the shielded metal arc welding  
17 process. This configuration and welding method is superior to Oxy-butt,  
18 BBCR, and BLSP girth welds, and does not exhibit the same susceptibility to  
19 ground movement-related failure. Therefore, even if the scope of the GPRP  
20 program included pipe constructed during 1956, Segment 180 would not be  
21 considered for replacement. Similarly, the 30-inch diameter portion of Line  
22 132 built in 1948 on GM 98015 was constructed using the same beveled-  
23 edge shielded metal arc welding technique. Regardless of the upper limit of  
24 pipe replacement under GPRP, neither Segment 180, nor any other section  
25 of Line 132 constructed in 1948 using 30-inch pipe, would have been  
26 considered for replacement under the GPRP.

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<sup>48</sup> Duller/North Supplement at 4.

<sup>49</sup> Duller/North Report at 6-49.

1 **CHAPTER 3E**  
2 **INTEGRITY MANAGEMENT AND RECORDS**

3 In several sections of her revised testimony, Ms. Felts faults us for missing  
4 records and inaccurate information in GIS, claiming that these recordkeeping issues  
5 prevent us from operating a functional integrity management program.<sup>50</sup> However,  
6 and as discussed in the testimony of John Zurcher (Chapter 3A), the integrity  
7 management rules and ASME B31.8S (adopted by reference) were drafted in full  
8 contemplation of the fact that operators would not possess complete records,  
9 particularly for pipelines that had been built prior to state and federal recordkeeping  
10 requirements or that were acquired from another operator. In consideration of the  
11 anticipated data gaps, the rules were drafted with provisions for the use of  
12 conservative, assumed values, and provided operators with prescriptive measures to  
13 be taken when data elements were unavailable. (Chapter 3.A.) Additionally, Ms.  
14 Felts identifies several record types (x-ray film, weld maps, and operating pressure  
15 history for the life of the pipeline) that are not required to be maintained under 49  
16 C.F.R. Part 192, and that are not required data elements under integrity  
17 management rules. While we acknowledge the importance of thorough and  
18 complete data gathering, and have implemented several processes to enhance the  
19 quality of our pipeline specification, maintenance, and operational data, we do not  
20 believe that any of Ms. Felts' charges prevented us from maintaining a functional  
21 integrity management program.

22 **1. Most Information in Pipeline History Files Exists in Pipeline**  
23 **Survey Sheets, GIS, or Job Files**

24 Ms. Felts claims that our integrity management program suffers due to  
25 the fact that we no longer maintain pipeline history files, and contends that  
26 we are missing an unspecified number of job files. PG&E discusses CPSD  
27 allegations regarding job files in Chapter 3.C. above. Due to the duplication  
28 of the pipeline history file data in other locations, including in hard copy  
29 pipeline survey sheets and electronically in our GIS, neither of these  
30 assertions affect our integrity management program.

31 As discussed more fully in Chapter 2.A above, pipeline history files  
32 were, as the Duller/North Report characterized them, "really a secondary

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<sup>50</sup> Felts Report §§ 4.1, 4.4 and 4.5.

1 source of information,”<sup>51</sup> as the information in the pipeline history files was  
2 centralized in pipeline survey sheets, and subsequently imported into our  
3 GIS database, which serves as a primary source of information in the  
4 integrity management program. Additionally, the documents in pipeline  
5 history files were themselves copies of other documents located in GM or  
6 Work Order job files. Our integrity management program has been able to  
7 rely on the data in GIS (itself sourced from pipeline survey sheets) and,  
8 where necessary, job files. Where information is not available in GIS or in  
9 job files, federal rules and ASME B31.8S provide for the use of  
10 conservative, assumed values.

## 11 **2. Weld Maps, X-Ray Film and Inspection Records Are Not** 12 **Necessary for Integrity Management Program**

13 Ms. Felts asserts that our integrity management program was deficient  
14 because we do not maintain all weld maps and weld inspection records.  
15 The premise of her assertion is that these records comprise “key pipeline  
16 data for the integrity management risk assessment model.”<sup>52</sup> In the Felts  
17 Supplement, CPSD alleges violations of 49 C.F.R. sections 192.241 and  
18 192.243, Section 451, Article II Section 13(b), and ASME Section B31.8.<sup>53</sup>  
19 These violations span from 1930 to 2011. The regulations regarding weld  
20 inspection practices, as well as corresponding recordkeeping requirements  
21 have changed over this 81 year period, as have PG&E’s practices to comply  
22 with these requirements. Contrary to Ms. Felts’ beliefs, weld inspection  
23 reports are not key data for integrity management risk assessment models,  
24 but rather play a limited role in the assessment of construction threats.

25 Prior to 1961, neither industry standards nor government regulations  
26 specifically required records of weld inspections to be kept for any period of  
27 time. Prior to 1955, industry standards merely called for visual inspection of  
28 welds for general workmanship concerns, with provisions for destructive  
29 testing of welds where a “reasonable doubt” regarding the excellence of  
30 workmanship existed. (E.g., ASA B31-1935 § 524, ASA B31.1-1942 § 524,  
31 ASA B31.1-1951 § 524.) In 1955, the ASA Standard Code for Pressure

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<sup>51</sup> Duller/North Report at 6-47.

<sup>52</sup> Felts Report at 35.

<sup>53</sup> Felts Supplement at 13.

1 Piping, Section 8, was amended to provide, for the first time, for the non-  
2 destructive testing of girth welds through radiographic, magnetic particle, or  
3 other acceptable method. (ASA B31.1.8-1955 § 828(a).) This code left the  
4 number and location of welds to be examined to the discretion of the  
5 operating company, and did not specify any recordkeeping requirement.

6 General Order 112, implemented in 1961, introduced the first  
7 recordkeeping requirement related to girth weld inspections. GO 112 called  
8 for a percentage of girth welds to be made on a sampling basis, with the  
9 frequency of inspection based on the class location, status as a tie-in, tap, or  
10 repair weld, or presence at a river, highway, or rail crossing. (GO 112  
11 § 206.1 (1961).) The General Order also indicated that “[a] record shall be  
12 made of the results of the tests and the method employed[.]” but did not  
13 specify any retention period. The inspection frequency and recordkeeping  
14 requirements were further modified in 1971 by General Order 112-C, which  
15 adopted federal regulations set forth in 49 C.F.R. Part 192. This included  
16 section 192.243(f), which increased the weld inspection frequency, requiring  
17 all welds in Class 3 and 4 locations to be non-destructively inspected. This  
18 section also specified that a record be made showing by milepost, station, or  
19 geographic feature, the number of girth welds made, the number tested, and  
20 the number and disposition of rejects. General Order 112-C stated, for the  
21 first time, that this type of record should be retained for the life of the  
22 pipeline. (49 C.F.R. § 192.243(f).) This requirement persists in the federal  
23 regulations through the present day.

24 Following implementation of General Order 112, we implemented  
25 Standard Practice 1605 in 1963 to comply with the new regulatory  
26 requirements for weld inspection and documentation procedures. This  
27 Standard Practice called for us to inspect, through radiographic or other  
28 methods, at least the minimum percentage of girth welds set forth by GO  
29 112. It also required inspection results to be recorded on a standard  
30 inspection report, which was to be maintained for the life of the pipeline  
31 facility in the pipeline construction job file. (P2-1286.) Standard Practice  
32 1605 was renamed as Gas Standard and Specification (GS&S) D-40 in  
33 1976 (P2-1287), and has been updated as necessary to ensure that PG&E’s  
34 girth weld inspection standards meet regulatory requirements. The revision

1 of D-40 in effect in September 2010 was provided as P2-1296 to PG&E's  
2 June 20, 2011 Response.

3 As suggested by Standard Practice 1605 and GS&S D-40, our practice  
4 has been to conduct inspections of girth welds on a frequency that meets or  
5 exceeds minimum requirements set forth in regulatory requirements.  
6 Results of these inspections were summarized on standard weld inspection  
7 reports that listed the location, commonly by geographic reference, the  
8 number of welds inspected, and the number and disposition (e.g., repair,  
9 replace) of welds that did not meet code requirements regarding weld  
10 acceptability in effect at the time. (E.g., API 1104.) In response to  
11 Commission directives issued in this proceeding, we reviewed tens of  
12 thousands of weld inspection reports that had been gathered as part of our  
13 MAOP Validation effort, eventually producing several thousand of these  
14 documents that were responsive to Paragraph Seven of the Commission's  
15 directives. (P7-0048 through P7-6935.) Contrary to Ms. Felts' conclusions  
16 that "few weld records can be found in PG&E job files,"<sup>54</sup> the volume of  
17 documents reviewed (and identified as a unique document type in PG&E's  
18 ECTS database) demonstrates that our practice has been to retain these  
19 types of records.

20 Ms. Felts also faults us for failing to retain weld maps, claiming that such  
21 records would "normally be a source of key pipeline data for the integrity  
22 management risk assessment model" and "would provide invaluable  
23 information to PG&E in its current efforts to locate and evaluate welds."<sup>55</sup>  
24 Ms. Felts includes a sample weld map, but the report does not provide any  
25 description or indication of what information present on the map we would  
26 use in our integrity management program.<sup>56</sup> Weld maps provide very  
27 limited information, other than limited geographic information relating to  
28 each girth weld. Weld maps are not identified in 49 C.F.R. Part 192 as a  
29 record type that must be created, reviewed, or retained as part of any  
30 construction, maintenance, or integrity management process. Furthermore,

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<sup>54</sup> Felts Report at 34.

<sup>55</sup> Felts Report at 35.

<sup>56</sup> Felts Report at 35, Figure 4.

1 Ms. Felts cannot point to any recordkeeping requirement relating to weld  
2 maps. (PG&E's Response to Records OII Data Request 4-Q37 (Ex. 3-22).)

3 From an integrity management perspective, information relating to the  
4 integrity of girth welds is relevant to consideration of the presence of a  
5 construction threat. Construction threats, such as wrinkle bends, stripped  
6 threads or broken couplings, and brittle girth welds (such as those  
7 constructed with oxyacetylene), do not present an integrity issue on their  
8 own. However, the presence of a construction threat in conjunction with the  
9 potential for outside forces (ground subsidence, earthquake, landslide)  
10 increases the integrity concern. (E.g., ASME B31.8S Appendix A § 5.3.) To  
11 address this concern, we integrate data relating to the ground movement  
12 potential along with information relating to pipe characteristics that may  
13 indicate the presence of a construction threat. The pipe data includes  
14 information relating to the type of girth welds (oxyacetylene vs. shielded  
15 metal arc welding) used, and the joint configuration (e.g., bell-bell chill-ring).  
16 This information provides more useful input into our integrity management  
17 threat identification process, as the type of weld or joint used is a better  
18 indicator of the girth weld's propensity to fail under ground movement-  
19 induced loading. Consistent with ASME B31.8S guidance, we perform non-  
20 destructive examinations of girth welds when they are exposed during the  
21 direct examination phase of in-line inspections or direct assessments to  
22 determine whether ground movement or other outside force has caused  
23 damage to the girth welds, and make repairs or replacements as necessary.  
24 (ASME B31.8S Appendix A § 5.5.)

### 25 3. **PG&E Maintains Operating Pressure History that Predates** 26 **Integrity Management**

27 Ms. Felts' claim that the lack of complete operational pressure history for  
28 all pipelines in our system (even those built decades before the integrity  
29 management rules were implemented) prevents us from properly conducting  
30 an integrity management program is not supported by the regulations.

31 As a general matter, operating pressure records (such as pressure  
32 charts and SCADA readings) are not considered life of the facility records to  
33 be maintained under Part 192 Subpart L. In fact, to the extent specific  
34 records retention guidance has existed, it has generally treated pressure



1 recording instrument charts as subject to finite retention periods.<sup>57</sup> One  
2 exception is where operating pressure records are relied upon or referenced  
3 when making decisions in compliance with integrity management rules, such  
4 as looking at the five year period prior to HCA identification for pipe with a  
5 manufacturing seam threat. In that circumstance, the records should be  
6 maintained for the useful life of the pipeline.<sup>58</sup> However, given that the  
7 Integrity Management rules did not take effect until 2004, they cannot apply  
8 to record retention practices prior to 2003. In any case, we maintain  
9 pressure data obtained from our SCADA system dating back to 1998 (with  
10 the exception of 1999, which was inadvertently and irretrievably lost).

11 Ms. Felts makes two identifiable claims regarding our operating history  
12 data. First, she claims that because we do not maintain operating pressure  
13 history for the life of the plant, we cannot give an accurate accounting of  
14 pressure excursions above MAOP for any pipeline in our system.<sup>59</sup>  
15 However, prior to integrity management rules, operators were not required  
16 to maintain records of overpressure events on transmission lines. Indeed,  
17 regulations allowed for occasional overpressure events that did not exceed  
18 110% of pipeline MAOP.<sup>60</sup> Implementation of integrity management rules  
19 created a new set of considerations for pressure history record retention, but  
20 only in regard to specific types of pipe enumerated in 49 C.F.R. sections  
21 192.917(e)(3) and (e)(4). These rules require that an operator limit the  
22 maximum pressure in an enumerated pipe segment to no greater than the  
23 operating pressure history for the five years that predate identification of a  
24 pipe segment as located in a high consequence area, or to conduct a hydro  
25 test in the event of a pressure excursion above the highest pressure  
26 recorded during the five years. As the rules relating to HCA identification  
27 were effective on December 17, 2004, this means that we must maintain

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<sup>57</sup> E.g., Regulations to Govern the Preservation of Records of Electric, Gas and Water Utilities, (NARUC 2007 Revision) (treating both Gas Pressure Department reports and Recording instrument charts such as pressure as 6 year records); 18 U.S.C. § 225.3 (specifying the retention period for gas transmission and distribution Recording Instrument Charts, such as pressure).

<sup>58</sup> 49 C.F.R. Part 192.517.

<sup>59</sup> Felts Report at 37-38.

<sup>60</sup> 49 C.F.R. § 192.201.

1 operating pressure history back to December 17, 1999. For the most part,  
2 our pressure history is available in our SCADA data historian from 1998  
3 through the present day. Therefore, we maintain operating pressure records  
4 for the period contemplated by the integrity management rules. The loss of  
5 data for the applicable period in 1999 does not negatively affect any integrity  
6 management consideration, as recovery of this lost data would only have  
7 the ability to increase the highest observed pressure during the five year  
8 period (which would raise the level to which these pipe segments could  
9 operate without requiring a hydro test).

10 Ms. Felts' second allegation is based on the claim that we lack an  
11 unspecified type of historic operating pressure record needed for integrity  
12 management risk assessment models. Ms. Felts indicates that PG&E "must  
13 enter a number into the model for each pipeline segment, whether or not  
14 there is a factual basis for the pressure selected,"<sup>61</sup> but does not identify  
15 what data type she is referring to. We do not know what Ms. Felts is  
16 referring to and cannot respond to this assertion without more information.

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<sup>61</sup> Felts Report at 38.

1 **CHAPTER 3F**  
2 **LEAK RECORDS**

3 The Felts Report and Supplement assert two violations relating to pipeline leak  
4 records. In Violation 21, Ms. Felts asserts that for a period of time ranging from  
5 1930 to 2010, our pre-1970 leak records were missing, incomplete, and inaccessible  
6 in violation of Section 451, Article II Section 13(b), ASME B31.8, and General Orders  
7 112, 112A, and 112B. In Violation 22, she asserts that for the period from 1970 to  
8 2010, our post-1970 leak records were missing, incomplete, and inaccessible in  
9 violation of Section 451, Article II Section 13(b), ASME B31.8, and General Orders  
10 112, 112A, and 112B. To support these allegations, she points to section 4.6 of  
11 her Report.

12 The Duller/North Report also contains an allegation regarding leak data. It  
13 asserts that “PG&E has failed to maintain a definitive, complete and readily  
14 accessible database of all gas leaks for their pipeline system as it has failed to  
15 routinely migrate all historical leak information from management system to  
16 management system.”<sup>62</sup>

17 Together, the Felts and Duller/North reports appear to make three allegations:  
18 (1) our leak data is inaccessible; (2) our leak data is missing or incomplete; and (3)  
19 the leak data is needed for pipeline safety purposes, including risk assessments.  
20 Below, we provide an overview of how we have historically maintained leak data,  
21 and then respond to each of the allegations.

22 **1. How We Historically Maintained Leak Data.**

23 Over the past 55 years, we have documented the discovery and repair  
24 of gas leaks in the Leak Repair, Inspection, and Gas Quarterly Incident  
25 Report (also referred to as an “A-Form” and previously known as a “Leak  
26 Test Report” and “Pipe Shut Down” record). An A-Form constitutes our field  
27 report of observed conditions relevant to gas transmission leaks, including  
28 leaks on welds. The document is filled out by field personnel responsible for  
29 leak detection, inspection, and repair. The form has evolved to call for field  
30 employees to gather a substantial amount of data including pipe  
31 specifications, soil type, cathodic protection, and external pipe condition.  
32 This evolution has been spurred both by our recognition of the need for

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<sup>62</sup> Duller/North Supplement at 5.

1 more detailed leak information and by changes in regulatory reporting  
2 requirements. We produced the earliest-located revision of this document  
3 (dating back to 1979) in our June 20, 2011 OII response as P2-1152.

4 With few exceptions, we have retained A-Forms either in job files or in  
5 separate files located at approximately 70 of our local offices. In the course  
6 of this proceeding, we have been collecting and digitizing A-Forms from  
7 local offices, as well as A-Forms stored in job files (collected as part of our  
8 MAOP Validation Effort). Thus far, we have collected, digitized, and stored  
9 over 30,000 documents in the Documentum database.

10 In the 1970s, we began to enter information from our A-Forms into  
11 electronic recordkeeping leak systems. In the early 1970s, we developed a  
12 mainframe computer program to track leak repairs across the service  
13 territory. Field personnel transmitted leak and repair data to this central  
14 database on a monthly basis.

15 In the late 1980s, we developed a program called PC Leaks to  
16 decentralize the data collection efforts of the mainframe program. Local PC  
17 Leaks systems were set up at the division level. If a division had multiple  
18 districts, each district would have a PC Leaks system; and if a district had  
19 multiple offices, each office would have a system. Employees entered leak  
20 information directly into these local systems. Once a month, programmers  
21 uploaded information from the local PC Leaks systems to a mainframe  
22 database system. The mainframe held information indefinitely. The local  
23 systems held information until they reached capacity, if ever.

24 In 1999, we developed a new leak and repair tracking database called  
25 the Integrated Gas Information System (IGIS). We migrated data for open  
26 leaks (that is, leaks that had not yet been repaired) from PC Leaks to IGIS.  
27 IGIS improved on our previous PC Leaks and Mainframe Leaks systems by  
28 allowing IGIS users to access all leak data across PG&E's service territory  
29 (whereas PC Leaks was a desktop application that could only provide data  
30 entered at the local office).

31 IGIS allows us to record, update, retrieve, and report information  
32 regarding gas leak locations, readings, repairs, incidents, inspections, and  
33 dig-in data for all gas transmission and distribution facilities. These IGIS  
34 capabilities also apply to gas pipe inspections not associated with gas leaks.

1 IGIS includes a “Leaks” module and an “Incident Data” module to  
2 differentiate between leaks and dig-in incidents. IGIS is capable of  
3 producing numerous types of reports to display leak status and history data.  
4 Among other things, we use data from the IGIS system to record and report  
5 gas incident data as required by GO 112-E (and produced in Gas Quarterly  
6 Incident reports).

7 Although IGIS is a source for leak information used in our Integrity  
8 Management program, the decisions around the migration of data and  
9 functionality from the mainframe and PC Leaks to IGIS predated ASME  
10 B31.8S and related federal integrity management regulations. Prior to  
11 issuance of ASME B31.8S and integrity management regulations, operators  
12 were not explicitly required to conduct trending analysis using historic leak  
13 data. As a result, there was no identifiable compliance-related reason to  
14 integrate large volumes of historic leak repair data into a new database.

15 In addition to IGIS, we maintain some leak data in our GIS. Our GIS  
16 contains transmission leaks from three data sources. One source is pipeline  
17 survey sheets, which contain indications of historic leaks. The second  
18 source is IGIS data, which represents the majority of the leaks in GIS. IGIS  
19 data is queried for transmission indications and mapped spatially after  
20 analysis of the repair information confirms the leak is on a transmission  
21 pipeline. The third source is the A-Form, which parallels IGIS after the time  
22 periods outlined previously.

## 23 **2. The Accuracy and Completeness of Leak Data**

24 Ms. Felts alleges that A-forms have “changed over time so that the  
25 historical record is inconsistent.”<sup>63</sup> While we agree that the format and  
26 information called for by A-Forms have changed over time, these changes  
27 reflect evolving industry awareness regarding the importance of data that  
28 can be obtained from leak records, and changes to regulatory reporting  
29 requirements.

30 We have historically used A-Forms as a source of data from which to  
31 complete annual reports, such as those required in PHMSA 7100.2-1, which  
32 asks operators to provide (among other items) the number of leaks in certain

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63 Felts Report at 40.

1 specified categories that have occurred on natural gas transmission and  
2 gathering lines during a given reporting year. Over time, these reporting  
3 requirements have required increased leak data granularity. For example, in  
4 the 1970s, PHMSA reports identified five potential categories of leak  
5 causes: corrosion, outside forces, construction, materials, and other. During  
6 much of the mid-1980s through the 1990s, the PHMSA reporting  
7 requirements combined construction and material-related leaks into a single  
8 category. In the early 2000s, PHMSA increased the specificity of reporting  
9 requirements, requiring operators to quantify leaks in the following  
10 categories: corrosion, natural forces, excavation, other outside forces,  
11 material and welds, equipment and operations, and other. Following the  
12 San Bruno incident, further modifications to these reporting requirements  
13 were finalized, requiring operators to identify leaks caused by external  
14 corrosion, internal corrosion, stress corrosion cracking, manufacturing,  
15 construction, equipment, incorrect operations, excavation damage,  
16 vandalism, natural force damage, other outside force damage, and other.  
17 These changes in reporting requirements demonstrate the evolving industry  
18 and regulatory awareness of the need to identify leak causes with more  
19 particularity. The evolution of PG&E's A-Form illustrates our awareness of  
20 this need.

21 Additionally, Ms. Felts claims that our A-Forms were poorly managed,  
22 inconsistent, and incomplete. While we share Ms. Felts' concerns regarding  
23 the completeness and accuracy of data in some A-Forms, we believe that  
24 Ms. Felts' limited analysis does not justify the conclusion that our leak  
25 recordkeeping practices have violated regulatory requirements for the last  
26 80 years. Ms. Felts points to a 2006 External Corrosion Direct Assessment  
27 pre-assessment attachment for her conclusion that our leak records are  
28 inconsistent and incomplete. The attachment identifies the mile point  
29 locations of 13 leaks on a segment of the line being assessed, but notes that  
30 the causes of the leaks were listed as "unknown (not on A Forms)." (P3-  
31 24119.) It is inaccurate to make such broad generalizations about the  
32 quality of data contained on A-Forms based on this limited analysis.

33 The leak data that appears to have been gathered for the 2006 ECDA is  
34 provided in attachment P3-24137. The attachment contains a mixture of

1 GIS leak data outputs and hardcopy A-Forms. Most of the 13 leaks  
2 identified in the 2006 pre-assessment attachment appear to have been  
3 leaks derived from the GIS leak data from pipeline survey sheets, rather  
4 than A-Forms or IGIS. As described above, these historic leak records  
5 contain limited information other than the year and location in which the leak  
6 was discovered. In contrast, the hardcopy A-Forms that appear to have  
7 been gathered as part of this project contain sufficient information to identify  
8 the leak source and leak cause. Even so, we recognize the importance of  
9 making leak records more accessible and, as discussed above, have  
10 undertaken an effort to gather and digitize all hard copy leak records in a  
11 central database.

### 12 **3. The Accessibility of Leak Data for Risk Assessments**

13 Our past decisions not to integrate all leak data into electronic  
14 databases were not made in a vacuum. As Bechtel's 1995 Review of the  
15 Transmission Priority Analysis (1994) Revision for the Gas Pipeline  
16 Replacement and Rehabilitation Program demonstrates, we considered  
17 integrating leak data in the mid-1980s as part of the GPRP. The decision  
18 was made not to do so. Bechtel summarized the thinking as follows:

19  
20 When the GPRP program was originally developed, it was recognized  
21 that it would require a large database to collect leak histories of all  
22 pipeline segments in order to identify leak cause variables and  
23 statistically correlate these variables to actual occurrences. It was  
24 concluded that a purely statistical approach to leak quantification was  
25 not feasible since it would be inaccurate (leak history data is not detailed  
26 sufficiently to establish a correlation) and prohibitively time consuming  
27 (due to the very large sample size required). Thus, in lieu of a statistical  
28 rendering of leak histories, relative probabilities were based upon  
29 cumulative leak history and engineering judgment.

30 (P3-20038.)

31  
32 Leak data is also relevant under Integrity Management principles, but  
33 not in the way that Ms. Felts asserts. Leak records are only required data  
34 elements for consideration of time-dependent threats, such as external and

1 internal corrosion. They are not required elements for assessing  
2 manufacturing threats. (ASME B31.8S, Appendix A.) While leak data is  
3 relevant to integrity management processes generally, our inability to locate  
4 records relating to a 1988 leak identified on an A-Form as a “longitudinal  
5 weld defect” did not factor into the manufacturing threat analysis for Line  
6 132 because, based on sound engineering analysis, there was no need to  
7 do so.

8 The leak record for this 1988 leak indicates that the leak was a  
9 “longitudinal weld defect” located at approximately mile point 30.5.  
10 Additional investigation into the leak, carried out by our Technical and  
11 Ecological Services group (TES, now known as Applied Technology  
12 Services, or ATS) revealed that the leaking section of pipe contained several  
13 imperfections in the longitudinal seam. However, despite the use of several  
14 investigative methods, the leak was too small to be located. This type of  
15 “pinhole” leak, while rare, is not unexpected in DSAW pipe. Indeed, DSAW  
16 pipe is viewed across the pipeline industry as safe and reliable, with a  
17 proven performance history. Incidents due to seam weld defects on DSAW  
18 pipe are rare. Prior to San Bruno, each pipeline incident involving a DSAW  
19 weld that was reported to PHMSA involved pinhole leaks. None resulted in  
20 longitudinal tears or rupture of the pipe. In short, pinhole leaks, such as the  
21 one identified in 1988, do not constitute a pipeline failure under integrity  
22 management rules, and are not evidence of a manufacturing threat. Had we  
23 located leak records relating to this leak, it would not have put our Integrity  
24 Management engineers on notice of the need to inspect the longitudinal  
25 seam of pipe used or similar to that installed on Line 132 in 1948.



1 **CHAPTER 3G**  
2 **THE QUALITY OF GIS DATA**

3 Ms. Felts also alleges violations relating to our GIS data. In Violation 24, she  
4 asserts that from 1974 through 2010, there was “bad data in Pipeline Survey Sheets  
5 and GIS,” resulting in violations of Section 451 as well as our “internal policies  
6 requiring retention of eng. records.”<sup>64</sup> To support this violation, she cites to  
7 Section 5.0 of her report, which states that incorrect, assumed, and missing data  
8 entries limits the use of GIS in our Integrity Management program. While we  
9 recognize the importance of complete, accurate, and reliable pipeline records, our  
10 use of GIS, premised upon prior pipeline survey sheets (and the accuracy of the  
11 data therein), is consistent with industry practice. Additionally, our use of  
12 conservative, assumed values is consistent with regulatory and industry consensus  
13 standards. Contrary to Ms. Felts’ claims, the data in our GIS does not constitute a  
14 violation of Section 451, and the GIS (which is not our system of record for pipeline  
15 records) did not replace engineering records.

16 We began to develop our Gas Transmission GIS in the early 1990s to enhance  
17 our capabilities in managing assets and facilities, and to provide a central access  
18 point for pipeline information within many groups in Gas Transmission. To populate  
19 GIS, we imported pipeline data from existing pipeline survey sheets, and accepted  
20 the accuracy of those records. While we have no specific data on the quality control  
21 process, we understand from individuals involved with GIS in its initial stages that we  
22 conducted a form of quality control process when inputting information into GIS.  
23 This included double-checking the accuracy of the transfer and randomly selecting  
24 points in GIS to compare back against the survey sheet entry. Mappers also  
25 reviewed selected data to identify questionable entries, such as illogical diameter  
26 changes. Despite the quality control measures, we are aware that data errors exist  
27 within the current GIS system (either from original pipeline data or introduced during  
28 the transfer), and have established a process by which field personnel can identify  
29 data inaccuracies and update that information in GIS. Our Risk Management  
30 Instruction No. 6, Rev. 1 describes the process for notifying the Mapping Group to  
31 update GIS when a change needs to be made to the system. (RMI-06, Rev. 1.)  
32 Spreadsheets containing the information that needs to be updated are then provided

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<sup>64</sup> Felts Supplement at 14.

1 to Mapping to update GIS. The Mapping Group enters any updates from Division  
2 into GIS to minimize any confusion in data entry.

3 Our GIS (and prior to GIS, our pipeline survey sheets) serves as a central point  
4 of reference, and provides Integrity Management personnel ready access to  
5 information. Where information is missing, our Risk Management Procedures call  
6 for Integrity Management personnel to conduct additional data gathering from hard  
7 copy records maintained in engineering libraries and in Division and District offices.  
8 (RMP-06, Rev. 1.) In the instances where this information cannot be identified, our  
9 use of conservative, assumed values in GIS is consistent with regulatory and  
10 consensus industry guidance, and does not prevent us from operating an effective  
11 integrity management program.

12 While our GIS serves as a central reference, it does not serve as our system of  
13 record for pipeline documents, which are maintained in hardcopy format in job files.  
14 However, we recognize the importance of having the information in the reference  
15 system be as complete and accurate as possible. In 2011, we began a huge effort  
16 to upgrade to a new GIS system.<sup>65</sup> We are in the process of validating pipeline  
17 MAOPs and creating pipeline feature lists based on the detailed review of  
18 voluminous source records. The product of this comprehensive effort is provided to  
19 key groups within the Company, such as Integrity Management and the team  
20 leading our Pipeline Safety Enhancement Plan. We are also developing an  
21 enhanced GIS platform into which verified and confirmed pipeline information will be  
22 integrated. We currently estimate that the new GIS will be complete by  
23 January 2013.

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<sup>65</sup> This effort is explained more fully in Chapter 5 of PG&E's Pipeline Safety Enhancement Plan filed in R.11-02-019.

**CHAPTER 3**  
**APPENDIX C**  
**CURRICULUM VITAE OF**  
**JOHN S. ZURCHER**

# The Blacksmith Group

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Houston, TX 77007  
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## RESUME OF JOHN S. ZURCHER

### FORMAL EDUCATION

Associate of Arts in Engineering Technology  
University of Southern Colorado - 1975

Bachelor of Science in Electrical Engineering  
University of Colorado - 1977

Master of Science in Business Administration  
University of Northern Colorado - 1981

### PROFESSIONAL AFFILIATION

Department of Transportation, Technical Pipeline Safety Standards Committee,  
1995 to 2001  
(Advisory Committee to DOT, appointed by the Secretary of Transportation)

American Society of Mechanical Engineers, B31.8 Section Committee,  
1980 to present

NACE International  
1993 to present

Gas Piping Technology Committee,  
1980 to 2000  
(Chairman of Transmission Division, 1986 to 1994)

American Gas Association, Operations Safety Regulatory Action Committee,  
1984 to 2001

Interstate Natural Gas Association of America,  
1980 to 2001  
(Chairman of Pipeline Safety Committee, 1992 to 2001)

Gas Technology Institute, 1993 to 2001  
(Chairman of Integrity Maintenance & Systems Operations, 1993 to 2001)

Pipeline Research Committee, International  
1993 to 2001  
(Co-Chairman of Design and Integrity Management, 1999 to 2000)

Department of Transportation, Mapping Quality Action Team  
1994 to 2000

Department of Transportation, Risk Management Quality Action Team  
1994 to 2000

## **MILITARY BACKGROUND**

United States Navy Submarine Service - 1970 to 1974  
Engineering Department, Auxiliary Division

## **CONGRESSIONAL TESTIMONY GIVEN**

Testified before the Committee on Transportation and Infrastructure, Congress of the United States in 1999 concerning the Reauthorization of the Natural Gas and Hazardous Liquid Pipeline Safety Program.

Testified before the U.S. House of Representatives Committee on Commerce in 1999 concerning the Reauthorization of the Natural Gas and Hazardous Liquid Pipeline Safety Program.

## **HONORS AND AWARDS RELATED TO PIPELINE SAFETY**

Pipeline Research Council International, Inc., Distinguished Service Award - 2002

Office of Pipeline Safety Certificate of Appreciation, Mapping Quality Action Team – 1998

U. S. Department of Transportation Certificate of Special Achievement, Risk Management – 1997

## **EXPERIENCE**

2002 to Present – Principal at P-PIC, Managing Director at The Blacksmith Group

Principal at Process Performance Improvement Consultants, LLC (P-PIC) and Managing Director at The Blacksmith Group. Major areas of emphasis are consulting to natural gas and hazardous liquid pipeline operators and consulting to various natural gas and hazardous liquid trade associations and research organizations.

As a consultant to pipeline operators, expertise is provided in many areas such as design, construction, pipeline integrity management, risk management, security, emergency response, operations and maintenance procedures and standards, pipeline safety regulations, operations and maintenance work processes, and process auditing.

As a consultant to trade associations and research organizations, expertise is provided in basic research, consensus standards development, pipeline safety regulations, pipeline integrity and risk management research, and communications liaison between these entities.

#### 2001 to 2002 – Vice President, HSB Pipelines

Consultant with Hartford Steam Boiler Inspection and Insurance Company (HSB), in the Pipeline Group. Major areas of emphasis were consulting to natural gas and hazardous liquid pipeline operators. In addition, consulting to various natural gas and hazardous liquid trade associations and research organizations.

As a consultant to pipeline operators, provided expertise in many areas such as pipeline integrity management, risk management and emergency response protocols. Additionally, expertise was provided in the areas of operations and maintenance procedures and standards, pipeline safety regulations, design and construction work processes and operations and maintenance work processes.

As a consultant to trade associations and research organizations I provided expertise for the development of many consensus standards. Additionally, expertise was provided in the areas of pipeline safety regulations, pipeline integrity and risk management research, and communications liaison between these entities and all involved stakeholders. I also was the primary author of the Natural Gas Industries Security Practices Report.

#### 1997 to 2001 - Manager, Pipeline Safety, Columbia Gas Transmission

Responsible for the products of a group of engineers and analysts in the areas of Pipeline Safety Compliance, Risk Management, Capital Maintenance Programs, Emergency Response, and the Engineer Training Program.

The Pipeline Safety Compliance Section is responsible for insuring compliance with applicable industry codes, Company standards, and Federal and State Regulations. This includes maintenance of the Operations and Maintenance Manual, incident reporting, crisis communications, code interpretations, compliance monitoring, responding to rule-makings and Pipeline Safety Re-authorizations.

The Risk Management Team is responsible for developing the Companies Risk Management Program. This includes model development for use in planning rehabilitation and other integrity programs, development of the Risk Management Plan for the Company and for developing the program to enter the Company into the DOT Risk Management Project.

The Capital Maintenance Team is responsible for insuring the integrity of the Companies pipeline facilities. This includes the management of the Companies pipeline integrity assurance program, pipeline replacements, pipeline rehabilitation, pipeline inspection including the smart pigging program, and pipeline efficiency improvement projects. The section is also responsible for setting of standards and developing procedures for pipeline operation and maintenance.

The Emergency Response Team is responsible for insuring the proper procedures are in place and that the proper training has been conducted to effectively handle a pipeline emergency. This includes making facilities safe, notification of regulatory agencies, liaison with local emergency response agencies and public officials and implementation of continuous improvement.

The Engineering Training Program provides for the recruitment of recent college graduates and their initial training and internship. This program provides for a structured two-year education of these individuals in order to provide them with a broad knowledge of company operations.

#### 1993 to 1997 - Director, Pipeline Services, Tenneco Energy

Responsible for the products of a group of engineers, consultants, technicians, analyst, and clerical personnel in the areas of Corrosion Control, Pipeline Engineering, Codes and Standards, Risk Management, Systems Applications, and AM/FM/GIS. Corporate Companies include: Tennessee Gas Pipeline Company, Midwestern Gas Transmission Company, East Tennessee Natural Gas Company, Iroquois Gas Transmission Company, and Channel Industries Gas Company.

The Corrosion Control Section is responsible for insuring the protection of the Companies steel infrastructure. This includes setting of standards and procedures for corrosion control, training of personnel, audits of compliance, quality assurance and quality control of all corrosion control activities and records.

The Pipeline Engineering Section is responsible for insuring the integrity of the Companies pipeline facilities. This includes the management of the Companies pipeline integrity assurance program, pipeline change-outs, pipeline rehabilitation, pipeline inspection including the smart pigging program, and pipeline efficiency improvement projects. The section is also responsible for setting of standards and developing procedures for pipeline operation and maintenance.

The Codes and Standards Section is responsible for insuring compliance with applicable industry codes, Company standards, and Federal and State Regulations. This includes maintenance of the Operations and Maintenance Manual, incident reporting, crisis communications, code interpretations, responding to rule-makings and Pipeline Safety Re-authorizations.

The Risk Management Section is responsible for developing the Companies Risk Management Program. This includes model development for use in planning rehabilitation and other integrity programs, development of the Risk Management Plan for the Company and for developing the program to enter the Company into the DOT Risk Management Project.

The Systems Application Section is responsible for administration of the Companies electronic forms and databases for all as-built activities and operational records. In addition the section maintains the house count database, performs annual relief and regulator valve capacity confirmations, and establishes MAOP's for the pipeline system.

The AM/FM/GIS Section is responsible for the design, development and implementation of the Companies GIS System. This system in conjunction with a Work Management System and a Document Management System will provide the necessary platform to move to an integrated Risk Management Program as well as manage the company's as-built records and operational records. The system will be implemented in 1997.

#### 1988 to 1993 - Manager, Engineering, Panhandle Eastern Corporation

Responsible for the products of a group of engineers, technicians, analysts, and clerical personnel to insure that all facilities are designed, constructed, operated, and maintained in accordance with applicable government regulations, industry codes, and Company standards. Corporate companies included: Algonquin Gas Transmission Company, Centana Energy Company, Panhandle Eastern Pipe Line Company, Texas Eastern Transmission Company, and Trunkline Gas Company

Worked on all Company projects involving facility additions and replacements in order to provide quality assurance. Responsible for insuring regulatory compliance with the Department of Transportation, the States in which the Corporation operates in, as well as other local municipalities. Participate in rule-making activities at the Federal and State levels writing regulations and giving testimonies on behalf of the Company, the industry, and engineering associations. Prepare and adhere to capital and operational budgets for the Company and my department.

Responsible for the Corporations AM/FM/GIS System. This system contains the facility data base and graphics elements, which comprise the Corporations mapping systems. These maps and data base are used to insure compliance with the regulations as well as to provide operating personnel with the necessary documents to perform their work.

Responsible for the As-Built Program for the Corporation. This program takes field mark-ups of construction and operating maintenance activities and as-built's the information into the appropriate permanent records.

Responsible for the Corporations Engineering Records System. These record systems contain all necessary records that document engineering activities. The records maintained include those items necessary to prove regulatory compliance as well as the retention of other business-related documents.

Responsible for the efforts of the Corporations Specialty Mapping Program. These specialty maps are used to present graphical information about the Corporations facilities for use by management and several departments within the Corporation.



### 1987 to 1988 – Consultant

Responsible for the pipeline safety programs for four intrastate operators. The companies were CITCO Refining and Chemical Company, Clarke Refining Company, AMOCO Gas Transmission Company, and Coastal Crude Gathering Company. These programs insure a proper compliance posture with the Texas Railroad Commission and DOT in the areas of inspections and maintenance of the pipeline systems, records and their systems, and design and construction specifications and standards.

### 1981 to 1987 - Manager, Engineering, Colorado Interstate Gas Company

Responsible for a group of technical personnel to insure that all facilities were designed, constructed, operated, and maintained in accordance with applicable government regulations, industry codes, and Company standards.

Worked on all Company projects involving facility additions and replacements in order to provide quality assurance. Responsible for insuring regulatory compliance with the Department of Transportation, the States in which operated in, as well as other local municipalities. Participated in rule-making activities at the Federal and State levels writing regulations and giving testimonies on behalf of the Company, the industry, and engineering associations. Prepared and adhered to capital and operational budgets for the Company and my department.

Worked on a collateral basis with the environmental group. Resources and workload was common between the two groups. Worked as an environmental analyst under the direction of the Manager, Environmental Services during periods when significant environmental work was done. Worked in areas such as spill prevention planning; environmental permitting; hazardous material handling, transportation, and disposal, and PSD surveys.

In 1982 given the additional responsibility for insuring regulatory compliance for two other subsidiaries, Wyoming Interstate Gas Company and Cody Gas Company.

In 1986 given the additional responsibility for insuring regulatory compliance for three other Coastal subsidiaries, two in hazardous liquid service, Coastal Pipeline Company and Coastal States Crude Gathering Company, and one in natural gas service, Coastal States Gas Transmission Company.

### 1979 to 1981 - Senior Engineer, Telecommunications, Colorado Interstate Gas Company.

Responsible for the design, installation, and maintenance of telecommunications equipment for the operational communication of data and information. This included microwave, measurement, supervisory control, telephone, and mobile radio systems. Developed state of the art electronic gas measurement systems and environmental monitoring stations.

1977 to 1979 - Field Engineer, Operations, Colorado Interstate Gas Company

Responsible for the construction of facilities for the transportation of natural gas including pipeline and compressor facilities, gas processing facilities, and auxiliary facilities such as instrumentation, automation and control, electrical, and structural/civil. Also responsible for solving operational problems as they relate to equipment and facilities.