BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Pacific Gas and Electric Company to Determine Violations of Public Utilities Code Section 451, General Order 112, and Other Applicable Standards, Laws, Rules and Regulations in Connection with the San Bruno Explosion and Fire on September 9, 2010.	I.12-01-007 (Filed January 12, 2012)

OPENING BRIEF OF THE UTILITY REFORM NETWORK

TURN
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I. INTRODUCTION AND SUMMARY

Pursuant to the Administrative Law Judges' Ruling Adopting Revised Schedule and Common Briefing Outlines dated February 4, 2003, The Utility Reform Network ("TURN") submits this opening brief in this Investigation into the conduct and practices of Pacific Gas and Electric Company ("PG&E") related to the San Bruno explosion and fire.

TURN only occasionally intervenes in Commission enforcement proceedings, but has devoted considerable resources to this Investigation and related Investigations 11-02-016 and 11-11-009, for two reasons.

First, the San Bruno calamity was the worst utility accident ever in California. The ensuing investigations by the National Transportation Safety Board ("NTSB"), the Independent Review Panel, and the CPUC's Consumer Protection and Safety Division ("CPSD") have revealed a disturbing array of unsafe practices by PG&E over a long period of time. Accordingly, these are undeniably the most important enforcement proceedings in the Commission's history. To help ensure that such a tragic accident never occurs again, the Commission must thoroughly document each of PG&E's dangerous practices and impose the fines and remedies that PG&E's unsafe conduct warrants.

Second, these enforcement cases will significantly affect the apportionment of financial responsibility for the billions of dollars of improvements PG&E must undertake in order to make its gas transmission system safe. A longstanding principle of Commission ratemaking, reflecting the requirements of California law, is that the Commission will not impose on ratepayers costs that result from a utility's imprudence; shareholders must absorb such costs. In connection with the Pipeline Safety Enhancement Plan ("PSEP") ordered in Decision ("D.") 11-06-017, PG&E has already begun incurring pipeline safety costs that are estimated to exceed $11 billion over the next five to eight years.[1] Although the Commission has tentatively apportioned between ratepayers and shareholders a relatively small portion of those costs in D.12-12-030 (regarding "Phase 1" of PG&E's PSEP), that decision made clear that more Phase 1 costs could be assigned to shareholders based on the outcome of these enforcement cases.[2] And PG&E has not yet presented its estimated $9 billion Phase 2 program. The Commission's conclusions in these enforcement cases will be key to determining how much of PG&E's PSEP costs (including Phase 2, to begin in 2015) is made necessary by PG&E's unsafe practices and thus should be borne by shareholders.[3]

For these reasons, TURN's main (though not exclusive) focus in this and the other enforcement proceedings has been on issues that are most likely to have an impact on the PSEP cost responsibility issues -- primarily recordkeeping, integrity management, and construction of Segment 180. In this brief, TURN presents its analysis of the record regarding construction of Segment 180, certain integrity management issues, and certain issues related to PG&E's corporate culture.[4]

This brief will show that PG&E committed serious violations of Public Utilities Code Section 451[5] with respect to the construction and operation of Segment 180 of Line 132, by

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[1] PG&E's Phase 1 PSEP (covering the period through 2014) called for $2.2 billion in expenditures, and PG&E has estimated that Phase 2, beginning in 2015, could cost an additional $9 billion.

[2] D.12-12-030, slip. op., p. 4 (making PG&E's rate recovery for Phase 1 PSEP costs subject to refund).

[3] From the outset of the enforcement proceedings and R.11-02-019, which considered ratemaking for PG&E's Phase 1 PSEP, the Commission has been clear about the linkages between the ratemaking determinations and the findings in these enforcement cases. The OIRs in both this docket and I.11-02-016 noted that some PSEP costs may "stem from" recordkeeping or other deficiencies and that the ratemaking proceeding would take note of the record evidence in the enforcement cases. I.11-02-016, p. 15 and I.12-01-007, p. 11. Similarly, R.11-02-019 stated that the Commission would take notice of other proceedings, including I.11-02-016, in the Commission's ratemaking determination.

[4] In the interest of a comprehensive and coherent analysis of PG&E's recordkeeping deficiencies, including those that relate to integrity management, TURN will defer that analysis to its briefs in I.11-02-016.

[5] Hereafter, statutory references are to the California Public Utilities Code.

(among other things) allowing dangerously defective pipe to be placed into service, and by transporting explosive and flammable gas through such pipe at excessively high pressures. In addition, PG&E violated Section 451 and various regulations in Subpart O of Part 192 of the Code of Federal Regulations, the integrity management regulations by, among other things: failing to identify the dangerous seam weld threat on Segment 180; failing to identify a manufacturing threat on Segment 180 by virtue of being more than 50 years old; failing to pressure test pipe segments (including Segment 180) with manufacturing threats for which PG&E "spiked" the pressure to evade regulatory requirements; and failing to recognize that many of the identified manufacturing threats (including Line 132) were unstable and required an assessment method other than external corrosion direct assessment ("ECDA"). These integrity management violations related not just to Segment 180 and Line 132 but also to hundreds of miles of transmission pipeline in PG&E's system.

II. BACKGROUND (PROCEDURE/FACTS)

TURN expects CPSD to fully summarize the relevant procedural and factual background to this proceedings. TURN reserves the right to respond to the background discussions of other parties in its reply brief.

III. LEGAL ISSUES OF GENERAL APPLICABILITY

A. Public Utilities Code Section 451 Imposes a Separate and Independent Obligation on PG&E to Furnish and Maintain Safe Gas Service and Facilities

As long as PG&E has been operating as a gas utility, it has been obligated to meet the requirements of Section 451 (and its predecessor provisions) that require every public utility to "furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities . . . as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." Although much of PG&E's conduct addressed in this proceeding violates specific and detailed provisions of the Commission's General Orders and federal pipeline safety regulations, PG&E's conduct also needs to be measured against the longstanding, bedrock obligation under Section 451 to maintain and operate a safe gas transmission system.

The Commission has made clear that its specific pipeline safety regulations in General Order ("GO") 112 (and its successors) are not intended to identify each and every unsafe practice that is proscribed by law. In adopting the first GO 112, the Commission emphasized that the new detailed safety rules do not supplant the utilities' "primary obligation" under Section 451 to provide safe service and facilities:

> It is recognized that no code of safety rules, no matter how carefully and well prepared, can be relied upon to guarantee complete freedom from accidents. Moreover, the promulgation of precautionary safety rules does not remove or minimize the primary obligation and responsibility of [gas utilities] to provide safe service and facilities in their gas operations. Officers and employees of the respondents must continue to be ever conscious of the importance of safe operating practices and facilities and of their obligation to the public in that respect.[6]

Moreover, in GO 112 itself, the Commission made clear that Section 451 continued to apply separately and independently of the new rules by specifying in Section 104.4 that "[c]ompliance with these rules is not intended to relieve a utility from any statutory requirements."

Similarly, the federal pipeline safety rules that became effective in 1970 establish only "minimum safety requirements."[7] California and the other states are free to impose additional requirements on the utilities, and the utilities' continuing obligations under Section 451 are one

[6] Decision (D.) 61269, approved Dec. 28, 1960 (Ex. PG&E-4 in I.11-02-016), slip. op., p. 12.
[7] 49 C.F.R. Section 192.1(a).

means by which California law may exceed the specific safety requirements detailed in the federal rules.

Notwithstanding the broad wording of Section 451, the Commission has ample authority to find violations based solely on Section 451 and to levy fines based on such violations. *Pacific Bell Wireless, LLC v. Public Utilities Commission*, 140 Cal. App. 4th 718, 741-743, 2006 Cal. App. LEXIS 905, *43-*50 (2006). The court in *Pacific Bell Wireless* cited with approval the Commission's decision in *Carey v. Pacific Gas & Electric Co.*, another gas safety enforcement action against PG&E, in which the CPUC explained:

> . . . it would be virtually impossible to draft Section 451 to specifically set forth every conceivable service, instrumentality and facility which might be defined as 'reasonable' and necessary to promote the public safety. That the terms are incapable of precise definition given the variety of circumstances likewise does not make Section 451 void for vagueness, either on its face or in its application to the instant case. The terms 'reasonable service, instrumentalities, equipment, and facilities' are not without a definition, standard or common understanding among utilities. Commission cases reviewing utility conduct frequently require that the conduct meet a standard of reasonableness. For example, in ratesetting proceedings, the disallowance of utility expenses, whether from contracts, accidents, or other sources are reviewed under a reasonableness standard.[8]

In sum, because PG&E's Section 451 obligation to maintain and operate a safe utility system applied throughout the time period covered by this case, the Commission should not hesitate to find Section 451 violations when the record supports such findings, with respect to PG&E's conduct both before and after the adoption of the more detailed state and federal regulations.

[8] D.99-04-029, 1999 Cal. PUC LEXIS 215, 85 CPUC 2d 682, 689.

B. While CPSD and Intervenors Have the Burden of Proving Violations By a Preponderance of the Evidence, PG&E Has the Burden of Proving Its Defenses

In this enforcement proceeding, CPSD and the intervenors have the burden of establishing by a preponderance of the evidence that PG&E has committed the alleged violations.[9] However, PG&E bears the burden of proof as to its defenses, consistent with the general rule that a party has the burden of proof as to each fact the existence or nonexistence of which is essential to the claim for relief <u>or defense</u> the party is asserting.[10]

C. In the Event That the Commission Finds that Particular Conduct Does Not Constitute a Violation, For Ratemaking Purposes the Commission Should Consider Whether the Conduct Was Prudent – A Determination On Which PG&E Bears the Burden of Proof

One of TURN's interests in these proceedings arises from the close relationship between the factual issues being adjudicated in this case (as well as I.11-02-016) and the Commission's ratemaking determinations regarding PG&E's PSEP. PSEP is a potentially extensive program of expenses and capital expenditures that PG&E and other gas utilities were required to propose in accordance with D.11-06-017. In D.12-12-030, the Commission approved cost recovery and associated rate increases for elements of Phase 1 of PG&E's PSEP.[11] However, recognizing that the findings in this proceeding and the other two pending PG&E pipeline safety enforcement proceedings may lead to additional ratemaking adjustments, the Commission ordered that the rate recovery approved in D.12-12-030 was subject to refund.[12] Accordingly, the Commission should be mindful that its determination in this case will relate not just to fines and other

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[9] D.12-02-032 (Tracfone Investigation), slip. op. at 4.
[10] *Id.*
[11] Phase 1 addresses PG&E's PSEP activities and expenditures through 2014, and Phase 2 covers PSEP activities and expenditures in 2015 and later years. PG&E has not yet presented a Phase 2 PSEP proposal, but PG&E has estimated that Phase 2 expenditures could run as high as <u>$9 billion</u>. TURN Reply Brief, R.11-02-019, May 31, 2012, p. 16.
[12] D.12-12-030, slip. op., p. 4.

remedies for adjudicated violations, but also to whether there should be additional disallowances of PSEP costs -- both the approved, but subject to refund, costs in Phase 1, and the yet-to-be proposed Phase 2 costs.

The Commission has long recognized -- and reaffirmed in D.12-12-030 – that, under the "just and reasonable" rate requirement of Section 451, shareholders should be required to absorb costs that are caused by imprudent utility management.[13] In addition, Section 463 similarly requires the Commission to disallow all costs resulting from any unreasonable error or omission by a utility that relates to efforts to recover costs of utility plant exceeding $50 million.[14] As a result, findings of imprudence in this case would warrant ratemaking disallowance of any Phase 1 or Phase 2 PSEP costs that result from such imprudence.[15]

Moreover, it is well settled that the utility bears the burden of proof on the issue of prudence and that the utility is not entitled to a "presumption of prudence."[16] Thus, in contrast to the burden of proof for adjudicating violations, PG&E has the burden of demonstrating the prudence of its actions for purposes of determining whether Phase 1 or Phase 2 PSEP costs should be disallowed.

In sum, while TURN believes that the record fully demonstrates the violations alleged by CPSD and intervenors, in the event the Commission disagrees, the Commission should make a

[13] D.12-12-030, p. 122 (Conclusion of Law 13: "It is reasonable for PG&E's shareholders to absorb the portion of the [PSEP] costs which were caused by imprudent management."); D.94-03-048, 53 CPUC 2d 452, 456 (not reasonable to pass on to Southern California Edison ratepayers costs resulting from the Mohave Coal Plant accident); D.85-08-102, 18 CPUC 2d 700, 715-716 (ratepayers not responsible for bearing the consequences of PG&E's imprudence with respect to the construction of the Helms Pumped Storage Project); D.84-09-120, 16 CPUC 2d 249, 283 ("it would be unconscionable from a regulatory perspective to reward . . . imprudent activity by passing the resultant costs through to ratepayers.").
[14] The $50 million threshold is clearly met. PG&E's approved PSEP Phase 1 costs exceeded $1 billion (D.12-12-030, App. E, Table E-4), and, as noted, proposed Phase 2 costs may reach $9 billion.
[15] A violation of applicable law, by definition, would constitute imprudence and warrant the disallowance of all costs resulting from the violation.
[16] D.93-05-013, 49 CPUC 2d 218, 220; D.85-08-102, 18 CPUC 2d 700, 709-710.

separate determination of whether PG&E has met its burden of demonstrating the prudence of the conduct in question. Such prudence determinations will be important to ensuring that, consistent with Sections 451 and 463, PG&E is not permitted to impose on ratepayers costs that result from PG&E's managerial imprudence.

IV. OTHER ISSUES OF GENERAL APPLICABILITY

At this time, TURN has nothing to discuss under this heading, but reserves the right in its reply brief to address points raised by other parties.

V. CPSD ALLEGATIONS

CPSD has convincingly demonstrated the violations alleged in its reports and testimony. TURN expects that CPSD's opening brief will comprehensively summarize the evidence supporting the alleged violations. In the following sections, TURN presents analysis and argument to emphasize key points in the record and to supplement CPSD's presentation.

A. Construction of Segment 180

There can be no doubt that PG&E committed egregious violations with respect to the construction, installation, and operation of the defective Segment 180. In assessing the record on this and other alleged violations, the Commission should not be fooled by PG&E's dogged efforts in its written and oral testimony to assess PG&E's conduct based on a hypothetical set of facts. PG&E wants the Commission to assume an alternative reality in which PG&E's conduct should be measured against the (woefully inadequate and inaccurate) information contained in PG&E's pre-explosion records regarding Segment 180, not the actual facts regarding Segment 180. Under this skewed and self-serving line of thinking, for example, PG&E did not operate the segment in excess of its correct design pressure because its inaccurate records justified a design pressure that exceeded operating pressure.[17] Rather than falling into this trap fashioned by clever lawyers, the Commission must take the facts as they are, not as PG&E incorrectly and inexcusably assumed them to be. And the facts are that Segment 180 was defective and posed a danger to public safety each day that PG&E allowed gas to pass through it.

The record indisputably shows that PG&E violated Section 451 in at least the following respects:[18]

- PG&E installed pipe in Segment 180 that did not meet PG&E's own specifications that were designed to ensure the pipe was fit for its intended purpose.
- PG&E failed to sufficiently inspect Segment 180 to ensure that the pipe met PG&E's specifications.
- PG&E cannot document that it conducted a pre-service pressure test of Segment 180, contrary to the ASME B31.1.8-1955 industry standards to which PG&E voluntarily subscribed.
- From the time of its installation in 1956 to the time of the fatal explosion on September 9, 2010, PG&E created an unreasonably unsafe condition by transporting natural gas through Segment 180.

1. PG&E Violated Section 451 By Installing Pipe With Pup Sections that Failed to Meet PG&E's Own Safety Specifications

The Segment 180 project called for the installation of the same pipe that had been used in the 1948 construction of Line 132.[19] PG&E's specifications for Line 132 prescribed 30-inch diameter, 0.375-inch wall thickness, 52,000-psig SMYS steel pipe, with no individual lengths of

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[17] Ex. PG&E-1, pp. 2-10 – 2-11 (Harrison).
[18] The following bullets are restatements of certain of the allegations made by CPSD. TURN does not intend this to represent a comprehensive listing of all of the violations alleged by CPSD under this heading, but rather to identify the violations that TURN has chosen to focus on for purposes of this opening brief.
[19] Ex. PG&E-1, p. 2-3 (Harrison). TURN cites to PG&E's testimony throughout this section to show the undisputed nature of the facts demonstrating the Section 451 violations.

pipe shorter than five feet.[20] The long seam on the pipe was to use the double submerged arc welding ("DSAW") process, by which the long seam was welded first on the outside of the pipe and then on the inside.[21]

The NTSB investigation found that portions of Segment 180 differed markedly from the specifications. Contrary to the five-foot minimum length requirement, Segment 180 contained six pup segments ranging in length from 3.5 to 4.7 feet.[22] In addition, the measured SMYS of the pup segments was significantly less than the specified 52,000 psig, ranging instead from 32,000 to 50,500.[23] Most significantly, the specified double weld was absent on the pups; no inside weld was found on the inside of the pipe.[24] PG&E did not contest any of these findings.

Installing pipe that was grossly inferior to PG&E's specifications is a clear violation of Section 451. Those specifications were designed to ensure that the pipe was fit to meet PG&E's intended uses for transporting an explosive gas. PG&E's witness Mr. Harrison conceded that installing pipe that did not meet PG&E's specifications is "PG&E's responsibility."[25]

2. PG&E Failed to Take Reasonable Steps to Ensure that Segment 180 Met PG&E's Specifications

Although PG&E does not know if Segment 180 contained previously used pipe, PG&E acknowledged that the pipe used during the 1956 project at least needed to be reconditioned before being placed in service.[26] That is because PG&E believes the pipe was drawn from stock

[20] Ex. PG&E-1, pp. 2-1 to 2-2 (Harrison).
[21] Ex. PG&E-1, pp. 2-1 to 2-3 (Harrison).
[22] Ex. CPSD-1 (CPSD Report), p. 16, citing Ex. CPSD-9 (NTSB Report), p. 41; Transcript (Tr.), Joint (Jt.) Volume (vol.) 3, p. 410: 9-13 (witness Harrison conceding that specifications called for pipe no less than 5 feet).
[23] Ex. CPSD-1, pp. 19-20.
[24] Ex. CPSD-1, p. 20.
[25] Tr., Jt. Vol. 4, p. 536: 16-24.
[26] Tr., Jt. Vol. 4, p. 599: 17-27 (Harrison).

left over from purchases made as early as 1948 and no later than 1953.[27] By the time of the Segment 180 project in 1956, the anti-corrosion wrapping on the outside of the pipe would have deteriorated in the sun, and, at a minimum, the old wrapping would need to be removed and the pipe re-wrapped.[28]

PG&E claims that a 1988 internal memo is likely representative of the process that PG&E should have followed for reconditioning pipe in the 1950s and 1960s.[29] The process included removing old coatings; visually inspecting the pipe, including longitudinal seams; and re-wrapping the pipe.[30] A 1960 PG&E standard practice document showed that reconditioning work would be performed at PG&E's Decoto Pipe Yard in Union City.[31] Mr. Harrison stated that at least the cleaning and inspecting part of the reconditioning process would have been performed at PG&E's Decoto Yard in the 1950s.[32]

Mr. Harrison admitted that, prior to re-wrapping, the nonconforming pup sections would have been visible to the naked eye.[33] He further acknowledged that, if PG&E's employees had done a visual inspection inside and out of the seam welds (as the 1988 memo says should have been done), they would have seen the missing seam weld.[34]

Accordingly, the record shows that PG&E should have inspected Segment 180 as part of the reconditioning process and should have discovered both the nonconforming pup segments

[27] Ex. PG&E-1, p. 2-3.
[28] Tr. Jt. Vol. 4, p. 599:27 – 600:5 (Harrison).
[29] Ex. PG&E-61 (I.11-02-016, Harrison), p. 3-29; Tr., Jt.Vol. 4, p. 481:7-22. TURN cites this 1988 document as evidence of the process that PG&E <u>thought</u> should be used for reconditioning pipe. However, as TURN will discuss in its forthcoming brief in I.11-02-016, in defending against CPSD's record-keeping allegations, PG&E has not met its burden of showing that the steps in the 1988 memo were actually followed by PG&E.
[30] Ex. PG&E-61 (I.11-02-016, Harrison), p. 3-29.
[31] Ex. PG&E-61 (I.11-02-016, Harrison), p. 3-29.
[32] Tr. Jt.Vol. 4, p. 580:7-9.
[33] Tr. Jt.Vol. 4, p. 542:7-10.
[34] Tr. Jt. Vol. 3, p. 394:15-20.

and the missing interior seam weld. Clearly, PG&E failed to perform this necessary safety inspection in violation of Section 451. If PG&E employees had actually inspected the pipe, it never would have been installed.[35]

Mr. Harrison's testimony suggests that PG&E will raise the defense that all the reconditioning work was done by a third party and that PG&E employees never saw the pup segments. This defense fails for three reasons. First, the testimony summarized above, including PG&E's own testimony, shows by a preponderance of the evidence that reconditioning work that included (at a minimum) cleaning and inspecting pipe was done at PG&E's Decoto Yard in the 1950s. Second, PG&E did not keep records documenting the reconditioning work that was done (or not done) on its pipe segments, even though such records would admittedly be "beneficial."[36] Accordingly, PG&E cannot meet its burden of showing by a preponderance of the evidence that a third-party vendor performed all of the reconditioning work. Third, in any event, PG&E cannot escape responsibility for its Section 451 violation by claiming that a third party was responsible. As the Commission held in *Carey v. PG&E*, utilities "may not escape by delegation to a third party the duty to provide safe gas service."[37] If PG&E is "accepting responsibility" as it claims,[38] then such responsibility must include failing to adequately inspect the reconditioned Segment 180 prior to installation.

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[35] Tr. Jt.Vol. 3, p. 394:22-24.
[36] Tr. Jt. Vol. 4, p. 465:17- 466:2 (Mr. Harrison acknowledging that he never saw any records documenting reconditioning steps, although such records would be beneficial). TURN will address PG&E's failure to document reconditioning work more thoroughly in its brief in I.11-02-016.
[37] D.99-04-029, 1999 Cal. PUC LEXIS 215, 85 CPUC 2d 682, 690.
[38] Ex. PG&E-1 (Harrison), p. 2-1.

3. PG&E's Inability to Document a Pre-Service Pressure Test of Segment 180 Violates Section 451

At the time that PG&E installed Segment 180 in 1956, the industry standards for gas transmission pipelines in ASME B31.1.8-1955 specified that all pipelines (such as Segment 180) to be operated at a hoop stress of 30% or more of the pipe's SMYS shall be given a pressure test in the field before being placed in operation.[39] The standards further required that records of such pressure tests be retained for the life of the pipeline.[40] PG&E admits that it cannot locate records showing that it conducted a post-installation pressure test in 1956.[41]

Even though it does not dispute these facts, PG&E contends that its inability to document the requisite pressure test does not constitute a violation because the 1955 ASME standards were voluntary. This claim ignores PG&E's obligation under Section 451 to maintain and operate a safe gas transmission system. In D.12-12-030 regarding PG&E's Phase 1 PSEP, the Commission has already found that PG&E's practice was to comply with the 1955 ASME standards regarding pressure testing;[42] PG&E does not dispute that point in this case. Clearly, PG&E itself made the judgment that the ASME standards identified reasonable practices for promoting safe pipeline facilities.

D.12-12-030 rejected PG&E's argument that the voluntary nature of the standards excused PG&E's inability to document compliance with them:

> We do not agree that the change from an industry practice to regulatory mandate somehow excuses PG&E's failure to retain the pressure test records. As noted above, the record supports the finding that PG&E stated that from 1956 on, PG&E's practice was to pressure gas system test pipeline prior to placing it in service and that the costs of such testing was passed on to ratepayers. As required

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[39] ASME B31.1.8-1955, Section 841.41.
[40] ASME B31.1.8-1955, Section 841.417.
[41] Ex. PG&E-1 (Harrison), p. 2-7.
[42] D.12-12-030, p. 59.

> by industry practice and prudent natural gas transmission system operations, PG&E should have created and maintained records of those pressure tests.[43]

Although the Commission in D.12-12-030 was examining PG&E's failings in the context of a ratemaking disallowance, the same reasoning compels the conclusion that PG&E's failure to comply with an industry standard that PG&E adopted as a company standard constituted an unreasonably unsafe practice in violation of Section 451. Indeed, PG&E acknowledged that pre-service pressure testing is important for safety reasons and that maintaining records of such tests is both good engineering practice and important for safety.[44]

4. From the Time PG&E Installed Segment 180 to Its Explosion, PG&E Operated an Unsafe Pipeline, Which Constitutes A 54-Year Continuing Violation of Section 451

PG&E admits that the defective pup segments, particularly the missing interior seam welds, made Segment 180 unsafe.[45] Mr. Harrison testified that, if PG&E knew about those missing welds, PG&E would have immediately taken the line out of service and replaced the pipe -- in fact would have "yank[ed] that pipe out of the ground."[46] These admissions alone are all the evidence the Commission needs in order to find that, for 54 years, PG&E operated an unsafe pipeline in violation of Section 451.

The fact that PG&E operated Segment 180 at pressures well in excess of the design pressure that PG&E should have calculated is further evidence that PG&E operated Segment 180 in an unsafe manner. Under ASME B31.1.8 -1955, PG&E should have determined the maximum allowable operating pressure ("MAOP") for Segment 180 by taking the lower of: (i) the design pressure of the weakest element and (ii) the pressure dictated by the pressure test

[43] D.12-12-030, p. 60.
[44] Tr., Jt. Vol. 3, p. 414:22-415:18 (Harrison).
[45] Tr., Vol. 3, p. 402:13-20 (Harrison).
[46] Tr., Jt. Vol. 3, p. 337:11- p.338:1 (Harrison).

divided by the appropriate factor for the class location.[47] The design pressure formula is based on the pipeline's actual features, including SMYS, wall thickness, longitudinal joint factor (reflecting the strength of the seam joint) and a "construction factor" based primarily on the class location for which the pipe was designed.[48] Had PG&E used the correct values for SMYS, wall thickness (reflecting the thinner than specified walls at the seam welds),[49] and Class Location 3 (not Class 2),[50] the design pressure would have been 172 psig, much lower than the 375 value that PG&E established as the Line 132 MAOP (when connected with Line 109).[51] This corrected calculation does not even take into account the lower joint factor ("E") that should have been used to reflect the missing interior weld, which would make the design pressure even lower. In short, PG&E operated Segment 180 (and Line 132 of which it was a part) at a much higher pressure than was safe under the applicable industry standards for establishing MAOP.

PG&E's contention that it did not know about the defective pup segments is not a defense to PG&E's ongoing violation. Section 451 requires utilities to furnish and operate safe systems; it does not excuse such failures based on a utility's ignorance of the unsafe condition. Allowing such a defense would undermine the important public welfare objective of Section 451. For this reason, the Commission has determined that public welfare statutes enforced by the CPUC impose strict liability on utilities.[52] If PG&E's ignorance defense has any relevance to this case, it would be to the issue of the egregiousness of PG&E's violations and hence the size of the fine, an issue that TURN will address in the fine and remedies brief. For now, TURN will simply note, as demonstrated in Section V.A.2 above, that, even if PG&E did not have actual knowledge

[47] ASME B.31.1.8-1955, Section 845.22.
[48] ASME B31.1.8-1955, Section 841.1.
[49] Ex. CPSD-5 (Stepanian Rebuttal), p. 7.
[50] Ex. CPSD-5, pp. 8-9.
[51] Ex. Joint 14 (CPSD).
[52] D.97-10-063, 76 CPUC 2d 214, 218-219.

of the defective pup segments, it should and would have known of them if it had properly inspected the pipe as part of the reconditioning process.

5. The Unsafe Practices Underlying These Violations Raise Disturbing Questions About the Safety of the Rest of PG&E's Gas System

Despite all of the attention that has been focused on Segment 180, to this day, PG&E states that it still cannot explain how it allowed the defective pup segments to go into service. PG&E's inability to answer this question raises the deeply unsettling concern that we still do not know how widespread the safety problems are in PG&E's system. Unfortunately, what we do know is that PG&E failed to have procedures in place to ensure that it installed pipe with the intended specifications. The unknown is the extent to which such lapses allowed other defective pipe to go into service. These concerns are exacerbated by PG&E's serious record-keeping deficiencies, which will be the focus of briefs by TURN and other parties in I.11-02-016. In addition, the unanswered questions regarding Segment 180 have important implications for the remedies for PG&E's violations, which TURN will address in its forthcoming fines and remedies brief.

B. PG&E's Integrity Management Program

1. In Violation of Federal Integrity Management Requirements, PG&E Failed to Identify the Dangerous Seam Weld Defects in Segment 180

In the detailed back and forth between CPSD and PG&E regarding the numerous Integrity Management violations that CPSD's testimony demonstrates, it is easy to lose sight of PG&E's most blatant – and tragic – violation: PG&E's failure to identify the dangerous seam weld defects in the pup segments in Segment 180. Section 192.917(a) of the federal regulations required PG&E to "identify and evaluate <u>all</u> potential threats to each covered pipeline segment (emphasis added)." It is undisputed that PG&E failed to identify the missing interior seam welds in Segment 180. Had PG&E met its obligation to identify this threat, PG&E would have been required under Section 192.933 to "take prompt action" to address this "anomalous condition." PG&E admits that such prompt action would have been to remove and replace the defective pup segments.[53] In other words, had PG&E identified the defective seam welds as required under Section 192.917(a), the San Bruno explosion and fire never would have happened.

PG&E's inaccurate records regarding the actual pipe that comprised Segment 180 cannot excuse this violation. The regulations charge operators with identifying and remediating the actual threats that exist in their systems, not just those that are apparent in the operators' faulty records. In a moment of unusual candor, even PG&E's Integrity Management witness Ms. Keas acknowledged to ALJ Wetzell, albeit grudgingly, that one of the purposes of the Integrity Management program is to reveal and disclose inaccurate records regarding what kind of pipe is in the ground.[54]

If PG&E can escape responsibility because its records were wrong, then operators have little incentive to ensure that their records are accurate. An Integrity Management program that is based on incorrect records that neither the operator nor regulator know about provides a false sense of security and therefore is probably more harmful than beneficial to pipeline safety.[55]

[53] Tr., Jt. Vol. 3, p. 337:11- p.338:1 (Harrison).
[54] Tr., Jt. Vol. 11, p. 1171:10-20 (Keas). Undoubtedly because she was placed in the extremely difficult position of having to defend a failed Integrity Management program that she did not even create, Ms. Keas' oral testimony was extremely evasive.
[55] TURN will more thoroughly address the records-related failings of PG&E's Integrity Management program in its briefs in I.11-02-016.

2. PG&E Should Have Used Methods Other Than Direct Assessment To Assess At Least A Portion Of Line 132, As Well As Other Segments On Its Pipeline System With Identified Manufacturing Threats

Federal Transmission Integrity Management regulations were adopted in 2003 and codified in 49 CFR Part 192. In brief, these regulations specified how a transmission pipeline operator should gather all relevant information in order to identify threats on pipeline segments located within populated areas (High Consequence Area), should assess those threats within a prescribed time period to determine the risk posed by the threats, and should then take action to respond to the assessments.

The NTSB Accident Report[56] and the CPSD Incident Investigation Report[57] both provide a comprehensive and highly critical evaluation of PG&E's integrity management program. The types of deficiencies identified in the NTSB and CPSD Reports reflect broad, system-wide issues that are not limited to Segment 180 or Line 132. These reports point out numerous deficiencies, including:

- PG&E failed to gather relevant and necessary data for threat assessment, including girth weld radiography records and data on seam leaks and test failures on similar DSAW pipelines, in its risk assessment process, as required by Part 192.917(c) and ANSI B31.8S;[58]
- PG&E did not ensure accurate information in the GIS system;[59]
- PG&E failed to use conservative assumptions when performing risk assessment.[60]
- PG&E's failed to appropriately consider cyclic fatigue in its threat assessment and risk ranking processes as required by Part 192.917(e)(2) and ASME B31.8S Section 2.2.[61]

[56] Identified as Exhibit CPSD-9 in the record.
[57] Identified as Exhibit CPSD-1 in the record.
[58] Exh. CPSD-1, pp. 32-34, 41-42 and 46-47; Exh. CPSD-9, NTSB Report, Sec. 2.6.1.
[59] Exh. CPSD-1, p. 32.
[60] Exh. CPSD-1, p. 31; Exh. CPSD-9, NTSB Report, Sec. 2.6.1.

TURN expects that the CPSD will address many of these shortcomings of PG&E's integrity management program in detail. Of particular relevance to issues raised in TURN's separate testimony is the question of the proper assessment of pipeline segments with identified manufacturing threats. PG&E had identified a manufacturing threat on Segment 181, as well as other segments of Line 132. PG&E also identified manufacturing threats on over 457 miles of HCA pipeline in 2004, though this number was reduced to 400 by 2009 due to pipeline or location reclassification.[62]

However, PG&E assessed the vast majority of this pipe using only external corrosion direct assessment (ECDA), a method not designed for assessing manufacturing threats. PG&E concluded that almost all of its manufacturing threats were "stable," and thus required no additional assessment. However, as explained below, PG&E's conclusion was erroneous due to at least two factors: 1) PG&E failed to incorporate other data on seam failures indicating the potential for threat instability, and 2) PG&E ignored the fact that lack of prior strength testing undermined the assumption of threat stability. PG&E now argues that an original mill test is sufficient to ensure threat stability, but this defense fails to consider the differences between a mill test and a required post-installation strength test, and also fails to consider the fact that mill tests may not have been conducted on much of its pipeline.

Of course, PG&E's assumption of threat stability completely fails for the pipelines it intentionally spiked, and PG&E should have hydrotested those lines pursuant to specific directives in Part 192.917 and ASME B31.8S Section 6.3.2.

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[61] Exh. CPSD-1, pp. 50-54.
[62] Exh. TURN-1, p. 10:19 – 11:2, Hawiger.

3. In Violation of Federal Safety Regulations and Section 451, PG&E Failed to Hydrotest Part of Line 132, and 86 Miles of Other Pipeline with Manufacturing Threats, That Were Intentionally Spiked Above the MAOP

a. In Order to Evade the Requirement to Hydrotest Pipeline, PG&E Intentionally Spiked the Pressure on Multiple Lines

The CPSD and NTSB Reports explain in detail how PG&E "spiked" the pressure on Line 132 in 2003 and 2008. PG&E spiked the pressure on Line 132 in December 2003 over the system maximum operating pressure ("MOP") within days of identifying the pipeline as an HCA location. PG&E believed that such spiking would allow it to argue that any future pressure increases would not exceed the "maximum operating pressure experienced during the five years preceding identification of the high consequence area," thereby avoiding a finding of an unstable defect pursuant to Part 192.917(e)(3).[63] PG&E repeated the pressure spiking in 2008.

As discussed in Section VI, TURN's testimony showed that PG&E's practice of intentional spiking was not limited to Line 132. PG&E spiked twelve lines (three of them more than once) comprising approximately 415.3 miles of pipeline.[64] Of this total, approximately 86 miles were included in the 2009 BAP as having a manufacturing threat.

[63] CPSD Report, p. 43. The CPSD Report documents in detail that the "pressure spikes" were actually performed a few days *after* identification of the segments as located in an HCA. Regardless of the actual timing, it is clear that PG&E's intent with the pressure spiking was to avoid any possibility of a future pressure increase that would trigger the need to consider an operating or manufacturing threat as unstable. Even if the Commission (contrary to the weight of the evidence) disagrees with CPSD that the 2003 pressure spikes violated federal regulations, PG&E's pressure spiking to evade the safety-protective strictures of the federal pipeline safety regulations was an unreasonably unsafe practice in violation of Section 451.

[64] Exh. TURN-1, p. 19, Hawiger/TURN.

b. Federal Regulations Require Strength Testing to Assess Seam Integrity When There is a Pressure Excursion Above the Historical Operating Pressure

Part 192.917(e)(3) states that, if the operating pressure on a segment with an identified manufacturing or construction threat increases above the maximum pressure experienced during the preceding five years, an operator must prioritize the segment as "a high risk segment." Section A4.4 of ASME B31.8S further explains that for a steel pipe with seam concerns, a hydrotest must be performed if the pressure is increased above the highest pressure recorded in the previous five years. Both the NTSB and the CPSD explain that, pursuant to Part 192.917(e)(3) and ASME B31.8S Section A4.4, a pressure excursion would trigger the need to perform a hydrotest to assess seam integrity.[65]

The CPSD Report correctly concludes that PG&E should have hydrotested Line 132 due to the pressure spiking in December of 2003.[66] Part 192.917(e)(3) is clear that, *if* the pressure goes above a five-year historical average, the operator *must* hydrotest the pipeline. PG&E's intent in performing the pressure spiking was to avoid any possibility that a future pressure increase would trigger the need to consider an operating or manufacturing threat as unstable, thus imposing the requirement to perform a hydrotest.

c. PG&E's Defense of Substantial Compliance Should Not Be Condoned Given Its Repeated and Deliberate Violations

PG&E refuses to admit that it violated the law by not pressure testing the segments that it pressure spiked, raising two technical defenses.

First, PG&E argues that technically it did not "identify" HCA until it filed its BAP in 2004, so that a pressure spike in December 2003 was not a pressure excursion "above the

[65] Exh. CPSD-9, NTSB Report, pp. 37, 112; Exh. CPSD-1, p. 40, 42-49.
[66] Exh. CPSD-1, p. 46-47.

pressure experienced in the five years *preceding* the date the segment was identified as an HCA segment."[67] As explained by CPSD, however, PG&E had actually identified the HCA well in advance of filing its BAP.[68] In any case, PG&E cannot argue that this was a mere technical aberrance, given that PG&E deliberately spiked pipeline pressure not once but fifteen times over the course of about seven years. Furthermore, as noted above, even if the Commission were to find that the 2003 pressure spiking did not technically trigger Section 192.917(e)(3), PG&E's intentional effort to evade the safety protective requirements of the rule was an unsafe practice in violation of Section 451.

Second, PG&E argues that it did not "significantly exceed" the Line 132 MAOP. PG&E admits it violated the letter of the law, and agrees that PHSMA had provided a non-binding regulatory interpretation of 192.917(e)(3) that states that any pressure excursion above the MAOP – no matter how small – triggers the requirement to hydrotest pipelines with seam manufacturing threats.[69] However, PG&E argues that the law is simply too strict, because a 2007 DOT Report authored by Kiefner shows that a small pressure increase above the MAOP would not render a stable manufacturing threat on a long seam as unstable.[70]

The Commission should not condone PG&E's defense of substantial compliance. First, PG&E's position conflicts with the letter of the federal regulations, as supported by the agency interpretation of the regulations. Second, PG&E willfully and purposefully violated the law for its own benefit, so as to reduce potential hydrotest costs. These pressure excursions were not accidental increases due to operational issues. They were a deliberate and oft-repeated practice designed specifically to evade the necessity to perform strength testing on pipelines. Especially

[67] Exh. PG&E-1, p. 4-24, Keas/PG&E (emphasis added).
[68] Exh. CPSD-170, p. 30, Stepanian.
[69] Exh. PG&E-1, p. 4-26, Keas/PG&E. PHMSA FAQ-221.
[70] Exh. PG&E-1, p. 4-25 to 4-27, Keas/PG&E.

given PG&E's lack of prior hydro test records and other vital pipeline documentation, such a practice cannot be treated lightly. Third, while the pressure increase was only a pound above the Line 132 MAOP of 400 psi, it was approximately 20 pounds above the historically high operating pressure of about 382 psi.[71]

The explosion of Segment 180 shows that even small pressure excursions can lead to catastrophic rupture when pipeline integrity is compromised.

4. PG&E Violated Federal Regulations by Classifying Almost All of Its Manufacturing Defects as Stable and Thus Relying on ECDA as the Primary Assessment Method

a. Section 192.917(e)(4) Requires Assessment of Certain Pipe for Seam Integrity

A manufacturing defect is generally a weakness present in the pipe material as a result of the longitudinal ("seam") weld used during the manufacturing process to create a cylinder from a flat plate of steel. There are different categories of defects, but they may generally reflect a crack or loss of pipeline material along the weld or in the weld heat-affected zone. A stable defect is one that will not grow so as to result in pipeline failure (i.e. leak or rupture) during the useful time of the pipe.[72] An unstable defect is one that could grow and fail during the useful life of the pipe.

The regulations do not require an operator to assess a manufacturing threat if it is stable, meaning there is no threat to seam integrity.

A construction defect generally refers to some weakness along the circumferential ("girth") welds of a pipe used to join two pipe segments together when the pipe is constructed in

[71] Exh. CPSD-1, p. 45.
[72] See, for example, Exh. PG&E-1, p. 4-19:17-23, Keas.

the field. Pipe segments are joined in the field due to the necessity to transport shorter pipe joints from the factory to the desired location, or to a temporary pipe storage yard.

Section 192.917(e)(3) explains that a defect can be considered "stable" if there had been no pressure increase above the MOP during the preceding five years, no increase in the MAOP, and no increase in cyclic fatigue stresses. The section also mandates that the operator prioritize the segment if there is a pressure increase above the MOP, and increase in the MAOP, or an increase in cyclic fatigue stresses.

Since PG&E claimed that none of these factors occurred on its pipelines, PG&E classified almost all manufacturing threats as stable.

However, Part 192.917(e)(4) further requires that *if* a segment has certain characteristics as specified in Section A4.3 and A4.4 of B31.8S *and* any segment in the pipeline system with such pipe has experienced seam failure, then the operator "must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies":

> If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4,[73] and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

Of particular relevance to Line 132 is the fact that Appendix A4.3 lists steel pipe greater than 50 years old as one of the conditions.

[73] Appendices A4.3 and A4.4 detail pipe with the following conditions: 1) Steel pipe greater than 50 years old; 2) mechanically coupled pipe; 3) acetylene girth welds; 4) pipe with joint factor of less than 1.

b. It is Undisputed that ECDA Is Not the Proper Assessment Method for Manufacturing Threats

For pipelines where PG&E identified manufacturing threats that could not be considered stable, PG&E had to properly assess the threat. Guidance for assessing manufacturing threats is provided in 49 CFR Sections192.917, 921, 923, 925, 927, 929, 931 and ASME/ANSI B31.8S (especially Sections 6 and Appendix 4). Section 192.913 incorporates B31.8S by reference, but Subpart O is controlling in case there is a conflict between Subpart O and B31.8S.[74]

Parts 192.921 through 192.931 and Section 6 of ASME B31.8S provide specific guidance on the type of assessment methods that should be used for various types of threats. In brief, the regulations specify that external corrosion direct assessment is an appropriate primary assessment method for addressing the threats of external corrosion, internal corrosion, and stress corrosion cracking. In-line inspection tools may be appropriate to identify metal loss due to corrosion, stress corrosion cracking, and mechanical damage. And hydrostatic testing is appropriate to evaluate seam integrity. Section 6.3.2 of the ASME Code also explains that pressure testing to address seam issues must be performed when raising the MAOP or when there is a pressure excursion, mimicking the requirements of Part 192.917(e)(3).

PG&E's own integrity management and integrity assessment procedures, as detailed in RMP-06, are consistent with the federal requirements detailed above. PG&E's plan was to use ILI for assessing manufacturing threats "whenever it is physically and economically feasible."[75] PG&E decided already in its 2004 Integrity Management Program not to use pressure testing as an assessment method unless "it may become apparent that pressure testing is the only feasible

[74] See, 49 CFR 192.907(b).
[75] Exh. PG&E-6, Tab 4-6, PG&E's RMP-06, "Integrity Management Program, Risk Management Procedure," Sec. 5.4. The first Integrity Management Program plan, dated December 9, 2004, was created to comply with Part 192.907

option."[76] PG&E states that it did not wish to hydrotest pipeline so as to minimize customer impacts due to potential flow interruptions.[77]

PG&E also agreed that direct assessment "can be used as a primary method only for external and internal corrosion, and stress corrosion cracking,"[78] and PG&E admits that the "code doesn't allow for the use of ECDA in the evaluation of manufacturing threats."[79] It is thus undisputed that ECDA is simply not an appropriate assessment method for manufacturing or construction defects.

c. PG&E Relied Exclusively on ECDA to Assess Its Pipelines

PG&E identified manufacturing threats on portions of Line 132, including Segment 181 immediately north of Segment 180, but did not classify the threats on Line 132 as unstable. Furthermore, in its 2009 BAP, PG&E identified 400 miles as having a manufacturing threat, but identified only 11.15 miles as having an unstable manufacturing threat.[80]

PG&E relied on ECDA to assess Line 132 even on segments PG&E identified as having a manufacturing threat. Similarly, PG&E relied on ECDA to assess 323 miles out the 400 miles of HCA pipeline with identified manufacturing threats, as discussed further in Section VI below.[81] PG&E in-line inspected 34.35 miles, and only 10.41 miles using a transverse field inspection tool.[82]

PG&E raises two general defenses concerning its failure to properly assess pipelines with manufacturing threats. First, it claims that all these manufacturing defects could be considered

[76] Exh. PG&E-6, Tab 4-6,RMP-06, Sec. 5.5.
[77] Exh. TURN-1, p. 15, Hawiger/TURN (quoting from PG&E Testimony in A.04-03-021).
[78] Exh. PG&E-6, Tab 4-6, PG&E RMP-06, Sec. 5.6.
[79] RT 961:4-7, Keas/PG&E.
[80] Exh. CCSF-1, p. 8:24, Gawronski.
[81] Exh. TURN-1, p. 14:1-3, Hawiger.
[82] Exh. TURN-1, p. 16:17-19, Hawiger.

"stable" pursuant to Part 192.917(e)(3), and thus required no assessment at all. Second, specifically with respect to Line 132, PG&E claims that the fact that a mill test was performed on the pipe rendered any manufacturing defect as stable.

d. If PG&E Had Considered the Relevant Evidence Concerning Pipeline Materials and Seam Failures, It Would Have Identified a Manufacturing Threat on Both Segments 180 and 181 of Line 132 and Classified Them as Unstable

PG&E violated Part 192.917(e)(4) by not considering certain evidence concerning the history of DSAW pipe manufacture prior to 1960, and by not considering specific evidence concerning leaks and weld defects on similar pipe on its own system. This evidence included data on prior leaks of Consolidated Western pipe of similar vintage on its system;[83] data from the 1989 PG&E Report on a leak on Line 132;[84] national data on leaks on Consolidated DSAW pipe in the "Vintage Characteristics of Pipelines" report;[85] and data from internal laboratory test reports from 1965, 1975 and 1996.[86]

PG&E identified a manufacturing threat on Segment 181, based on the fact that this segment was more than 50 years old in 2004 and thus fell within the scope of A4.3. However, PG&E did not classify this threat as unstable. CPSD demonstrates that by considering the available data on DSAW seam failure history, both nationally and specifically on PG&E's system, PG&E should have classified this threat as unstable and performed a hydrotest of Segment 181.

There is, however, a separate violation with respect to Segment 180. PG&E had not identified a manufacturing threat on Segment 180 itself due to the fact that it was installed in

[83] Exh. CPSD-1, p. 33-34.
[84] See, for example, Exh. CCSF-1, p. 5, Gawronski.
[85] Exh. CPSD-1, p. 46-47; See, also, Exh. CCSF-1
[86] Exh. CCSF-1, p. 11-12, Gawronski.

1956. Thus, PG&E did not consider this segment "greater than 50 years old" at the time it created its 2004 Baseline Assessment Plan. However, PG&E admitted in oral cross examination that the age of the pipeline should be measured based on the manufacture date of the pipe, not based on the installation date of a particular line.[87] Thus, PG&E should have identified a manufacturing threat on Segment 180. Then, pursuant to the requirements of Section 192.917(e)(4), it should have classified that threat as unstable by considering additional evidence and should have conducted a hydrotest.[88] PG&E's failure to properly identify and assess the threats on Segment 180 constitutes a separate violation of integrity management regulations.

e. PG&E's Argument that a Mill Test Is Sufficient To Ensure Threat Stability Ignores the Fact That Mill Tests May Not Have Been Conducted on All Pipe, and that a Post-Installation Strength Test Provides Much Greater Assurance of Seam Integrity

PG&E lacks any records of a hydrotest on Line 132, as well as on the hundreds of miles of HCA pipeline scheduled for testing or replacement as part of its Pipeline Safety Enhancement Project.[89] Due to the lack of any records of a strength test on Line 132, PG&E falls back on the defense that a mill test was sufficient to "ensure that when a pipeline is placed in service any remaining manufacturing defects will be too small to fail at the maximum operating pressure."[90]

In response to CPSD's argument that PG&E should have considered other evidence of long seam imperfections on Consolidated Western pipeline, PG&E's argues that "the long seam imperfections identified during the 1948 radiography do not constitute unstable manufacturing

[87] RT (Jt. Vol. 10) 966:10-26, Keas/PG&E.
[88] Of course, PG&E would have had to determine that Segment 180 could not be "seamless" due to the fact that no seamless pipe of such diameter was manufactured.
[89] D.12-12-030.
[90] PG&E-1, p. 6-5:14-19, Kiefner/PG&E.

threats because that pipe had been hydro tested during the pipe manufacturing process."[91] PG&E further explained that based on the Kiefner 2007 Report, as a result of the mill test "any manufacturing imperfections that remained in the pipe (those that did not fail during the hydro test) would be considered stable and not at risk of growing to failure during the useful life of the pipeline."[92]

PG&E's "mill test" defense cannot justify a wholesale assumption of threat stability, either for Line 132 or for the hundreds of miles of other pipeline with identified manufacturing threats and no evidence of hydrotesting.[93]

The mill test is a high pressure test conducted on a single short pipeline section for only a few seconds.[94] There are fundamental problems with relying on a mill test as the basis for assuming defect stability. First, PG&E explained that a mill test was a contractual requirement only for certain pipe specification, such as API-5L pipe. The pipeline purchased for Line 132 in 1948 was such pipe, but not all pipe with identified manufacturing threats was necessarily API-5L pipe. Second, the interview of a former Consolidated Western employee casts doubt on the notion that Consolidated Western conducted a mill test on each and every pipe joint. The employee stated that after cold expansion Consolidated Western strength tested only about one of every fifty pipe joints.[95]

Third, as Dr. Kiefner explained in his 2007 Report, a mill test "offers no protection from a fatigue crack arising from rail shipment of the pipe."[96] This point may be particularly relevant

[91] Exh. PG&E-1, p. 4-19:6-9, Keas/PG&E.
[92] Exh. PG&E-2, p. 4-19:17-20, Keas/PG&E.
[93] See discussion in Section VI below.
[94] See, for example, Exh. CPSD-143, Moody Engineering, July 19, 1949, p. 34.
[95] Exh. CPSD-305, p. 11. See, also, Jt. RT 1091-1093, Keas/PG&E.
[96] Exh. PG&E-7, ex. 4-21, p. 27 (Kiefner, 2007). This issue is also addressed by CPSD witness Stepanian. See, Exh. CPSD-5, p. 28.

since DSAW and flash welded pipe is more susceptible to "transportation fatigue."[97] In the same vein, a mill test provides no indication of any subsequent potential defects, whether due to recoating/reconditioning, moving pipe around from storage to installation site, moving pipe around from PG&E's storage yards to other locations, or simply moving and restacking pipeline at the storage yard. As noted in Section V.A above, PG&E acknowledges that Segment 180 was constructed from pipe in stock and must have been transported to the site.

Indeed, the argument that industry could rely on mill tests is illogical, given the voluminous evidence that one of the primary safety procedures adopted in the 1955 version of ASME B31.1.8 was the requirement for a post-installation strength test:

> 841.411 All pipelines and mains to be operated at a hoop stress of 30% or more of the specified minimum yield strength of the pipe shall be given a field test to prove strength after construction and before being placed in operation.[98]

The CPUC adopted this requirement as part of GO 112 in 1960. And federal regulations codified this requirement for a "Subpart J" hydrotest, specifically mandating a hydrotest at 1.25 times the MAOP for at least 8 hours. PG&E's argument that a mill test can be sufficient to assess pipeline integrity leads to the obvious question – why have industry standards codified by 1955, California state standards codified in 1961 and federal regulations adopted in 1970 - all focused on the essential need for a post-installation strength test lasting at least one hour or longer? The answer is that a mill test cannot provide the same assurance of pipeline integrity or threat stability as a post-installation strength test.

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[97] Exh. Jt-49, Table E-10, p. E-12.
[98] ASME B31.1.8-1955, Section 841.411.

C. Recordkeeping Violations

It appears that CPSD's recordkeeping allegations in this case are subsumed within the broader recordkeeping allegations in I.11-02-016. In the interest of a full and coherent presentation, TURN will present its affirmative arguments regarding PG&E's recordkeeping violations in its brief in I.11-02-016.

D. PG&E's SCADA System and the Milpitas Terminal

At this time, TURN has no issues to discuss in this section of the brief that have not been discussed elsewhere, but reserves the right in its reply brief to address issues raised by other parties.

E. Emergency Response

At this time, TURN has no issues to discuss in this section of the brief that have not been discussed elsewhere, but reserves the right in its reply brief to address issues raised by other parties.

F. PG&E's Safety Culture and Financial Priorities

1. The Evidence In This Proceeding Shows That PG&E Significantly Overearned On Its Gas Transmission And Storage Operations, And That PG&E Used Those Earnings To Benefit Shareholders Rather Than To Ensure The Safe Provision Of Utility Service To Customers

The Overland Audit Report[99] provides considerable detail concerning PG&E's spending and earnings history for its Gas Transmission and Storage (GT&S) operations during the time period 1996-2010. The Overland Report provides data on actual recorded spending and actual revenues, and compares that data to authorized revenue requirements and the expense and capital forecasts embedded in those requirements.

[99] Identified as Exhibit CPSD-168.

PG&E and Overland generally agree on the levels of actual capital spending during 1999-2010, with some limited dispute concerning the level of O&M spending.[100] The primary areas of disagreement concern the "imputed adopted" revenue requirements, meaning the expense and capital forecasts that were *authorized* in rates.[101] This disagreement results in differing conclusions regarding whether and how much PG&E underspent as compared to authorized revenue requirements.

However, irrespective of conclusions regarding exactly how much PG&E underspent in specific categories, what is undisputed is that PG&E's Gas Transmission and Storage division *actually* earned an average return on equity of at least 14.3% from1999-2010, as compared to an average *authorized* return on equity of 11.2%.[102] The result of these overearnings is that PG&E collected at least $430 million in additional shareholder profits over those twelve years than it would have collected had costs and revenues been exactly as forecast.

Shareholder earnings in excess of authorized reflect some combination of higher than forecast revenues and lower than forecast costs. There is dispute about exactly the amount and nature of those higher revenues and lower costs. Overland concludes that the overearnings resulted about equally from higher revenues versus lower spending, while PG&E argues that the overearning resulted exclusively from higher than forecast revenues. TURN reserves the right to comment on evidence concerning these issues in our reply brief.

PG&E claims that one cannot conclude that the excess earnings of $430 million went straight to shareholder pockets, because GT&S earnings are separated only for ratemaking

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[100] See, for example, Exh. PG&E-10, Figure 5, p. 24 and Figure 12, p. 48, O'Laughlin/PG&E.
[101] The disagreements are succinctly summarized at p. 4-5 of Mr. Harpster's rebuttal testimony, Exh. CPSD-170.
[102] Exh. CPSD-168, Tables 5-1 and 5-2, p. 5-2 and Exh. CPSD-170, p. 149; PG&E calculated an even higher average ROE of 14.6%.

purposes, but not for purposes of corporate accounting. However, there is ample evidence that much of this overearning did not support the provision of utility service to customers.

PG&E provides a chart showing utility-wide earnings for 1999-2010.[103] However, as explained by Overland, the energy crisis and PG&E's bankruptcy filing in 2001 skew the numbers for 2000-2003 so as to make any coherent analysis impossible for the full time period.[104] PG&E exited bankruptcy in December 2003.[105] Excluding the 2000-2003 time period, PG&E's own data show that for 2004-2010 PG&E overearned by a total of 168 basis points. This strongly suggests that gas transmission and storage overearnings flowed to the overall company bottom line during this period.

Even if PG&E allocated some of the excess earnings from GT&S to spending on the gas distribution or electric portion of the company, the further relevant question is what did PG&E spend the money on? TURN has participated in all of the distribution GRCs during the 1998-2010 time period. We have criticized PG&E in each of these case for spending lavish amounts on management compensation packages, spending higher than forecast amounts on annual incentive programs, excessive software and real estate investments, excessive and unnecessary "business transformation" costs, and various other projects of dubious value to ratepayers. PG&E's corporate culture on a company-wide basis was little different from the profit-oriented culture described in the Overland Audit Report and the Report of the Independent Review Panel.

In sum, the Commission can find as an undisputed matter of fact that PG&E 1) overearned an average of 300 basis points each year 1999-2010 on its gas transmission and storage operations, and 2) overearned an average of 24 basis points each year 2004-2010 on its

[103] Exh. PG&E-10, Figure 23, p. 80, O'Laughlin/PG&E.
[104] Exh. CPSD-170, p. 145-146, O'Laughlin/PG&E. Mr. O'Laughlin identifies other problems with the use of the CPUC annual earnings reports as the basis for assessing actual ROE.
[105] See, D.03-12-035.

combined electric and gas operations. The evidence strongly suggests that PG&E's gas transmission and storage overearnings did not benefit the provision of utility service to customers.

2. PG&E Eliminated or Deferred Forecast Work In Order To Cut Costs and Significantly Reduced the Use Of In-Line Inspection After 2008

While PG&E argues that it did not 'underspend' at all (or very much), PG&E ignores the other relevant issue – the amount of necessary work performed. There is only partial evidence in the record of this proceeding concerning the amount of work embedded in cost forecasts, versus the amount of work actually done. But the available evidence suggests PG&E eliminated or deferred necessary work in order to avoid spending more than its authorized revenue.

a. PG&E Deferred Specific Projects to Reduce Costs

The evidence indicates that PG&E deferred specific replacement and in-line inspection projects in an attempt to reduce costs.

First, the Overland Report documents numerous examples, starting in 2008 and continuing through 2010, where PG&E cut or deferred projects to reduce costs.[106] These examples include:

- Deferring four planned projects, with a total cost of $2.657 million, from 2008 to 2009;[107]
- Abandoning the ILI planned for Line 215 in 2008, in favor of the less costly ECDA;[108]
- Reducing actual 2008 maintenance spending on Integrity Management to 21% below the initial request;[109]

[106] See, exhibit CPSD-168, pp. 7-6 through 9-19.
[107] Exh. CPSD-168, p. 7-10, Table 7-4.
[108] Exh. CPSD-168, p. 7-9.
[109] Exh. CPSD-168, p. 7-12.

- Reducing Integrity Management expenses in 2009 by at least $6 million by altering assessment from ILI to ECDA and deferring 41 miles of integrity management assessments to 2010;[110]
- The "Reduce Pipeline Project Work Initiative" deferred all work in 2010 that was not required by code so that the 2010 maintenance budget did not increase above 2009.[111]

PG&E's response to these allegations is almost nonexistent, since the allegations are based on explicit PG&E internal documents. PG&E's witness Martinelli presents less than a page of testimony where he concludes that PG&E had always planned to use ECDA on Segment 180 specifically, so that none of the potential changes or deferrals described in the Overland Audit Report could have affected Segment 180 specifically.[112] But Mr. Martinelli does not even attempt to rebut the analysis of PG&E's deferrals of other work related to integrity management and pipeline maintenance.

Moreover, PG&E had forecast in its 2008 GT&S rate case that it would replace approximately 1.42 miles of Line 132 located just north of the explosion site.[113] PG&E forecast spending $4.673 million on this project, almost one-fourth of the total spending of $19.940 million forecast for Transmission Pipeline Reliability (MWC-75) in 2009.

PG&E deferred this project and included exactly the same project in its forecast for 2013 capital expenditures submitted with the 2011 GT&S rate case.[114] PG&E explained that the project was necessary because, "coupled with the consequences of failure of this section of pipeline, the likelihood of a failure makes the risk of a failure at this location unacceptably high."

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[110] Exh. CPSD-168, p. 8-3 and 8-10.
[111] Exh. CPSD-168, p. 9-19.
[112] Exh. PG&E-1, p. 12-3:5-23, Martinelli/PG&E.
[113] Exh. TURN-2, PG&E Workpapers from A.07-03-012.
[114] Exh. TURN-3, PG&E Workpapers from A.09-09-013.

PG&E's response to this factual evidence is not credible. PG&E's rebuttal consists of one conclusory paragraph of testimony from Mr. Martinelli, who summarily states that based on his "review of the materials" he found no evidence that the project was delayed due to "budgetary considerations."[115] Mr. Martinelli's conclusion is apparently based on the fact that in early 2008 PG&E eliminated this segment from its "top 100" list based on incorporating information from a previously conducted ECDA analysis.[116] The results of this new information are present in PG&E's risk algorithm results for this segment, which show that due to an "EC algorithm change in 2009" the external corrosion threat likelihood of failure was significantly reduced, thus reducing the total risk number for this segment.[117]

However, even this "explanation" does not correlate with PG&E's actions. The risk table shows that the "future risk" value of this segment went down between 2007 and 2008 (from 2095 to 1969) and then down again between 2008 and 2009 (from 1969 to 1847). But PG&E then *included* this segment in the rate case filed in September of 2009, and used the 2007 "total risk of 2095" value in its "justification of the project."[118]

Mr. Martinelli's "opinion" in this case should be given very little weight. Mr. Martinelli was unfamiliar with any of the underlying documents.[119] He had not interviewed any of the relevant PG&E employees. Indeed, he had not apparently prepared or seen the data response

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115 Exh. PG&E-1, p. 12-3:26 to 12-4:2, Martinelli/PG&E.
116 Exh. TURN-4.
117 Exh. TURN-5.
118 Exh. TURN-3. PG&E provides a general description of its risk assessment algorithm and risk management process at p. 4-3 to 4-5 of the testimony of Keas (PG&E-1).
119 See, for example, 6 RT 490:25 – 491:14 (no detail on reasons for risk reevaluation); 493:26-27 (not familiar with details of risk assessment algorithm); 504:7-15 (no comment on why PG&E used 2007 risk values in the 2009 rate case).

which explained what "risk management considerations" led PG&E to reprioritize the project.[120] Indeed, his entire testimony was based on the conclusions of another person, Ed Strache, as presented in a deposition in the San Bruno Civil proceedings.[121]

None of this makes much sense. At a minimum, PG&E's "defenses" demonstrate a lack of coordination and consistency between PG&E's risk assessment, integrity management and rate case analyses and presentations. But more likely, PG&E deliberately deferred the replacement project from 2009, for reasons that are likely exactly the same as the reasons PG&E management provided in the various internal memos recommending deferral of ILI projects, as discussed above.

Deferring a project of this type and including it in the very next rate case is the epitome of the type of deferred maintenance that the Commission has repeatedly disallowed from rate case requests.[122]

b. **PG&E Significantly Reduced the Use of In-Line Inspection After 2008**

As documented in TURN's testimony, PG&E significantly reduced the use of in-line inspection as an assessment method after 2008. At the start of its Integrity Management Program

[120] 6 RT 489, Martinelli/PG&E. This situation led to the Catch-22 situation where Mr. Martinelli could not authenticate or explain the meaning of PG&E's own risk documents that PG&E had provided to TURN in response to discovery submitted concerning Mr. Martinelli's own testimony.
[121] 6 RT 499:13-21. PG&E provided numerous depositions to TURN with all names redacted. Thus, we could not confirm or deny Mr. Martinelli's hearsay account of what Mr. Strache said in those depositions. TURN can only conclude that PG&E offered up witness Martinelli, whom they paid $390 per hour, as a noted industry expert who could not be subject to detailed questioning concerning the bases for his opinions.
[122] See, for example, D.00-02-046, Conclusion of Law 15, p. 536 ("It would be unjust and unreasonable to make ratepayers responsible for expenses directly attributable to deficient or unreasonably deferred maintenance, or to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past."); See, also, D.04-07-022, Sec. 4.3.3, *mimeo.* at 98-99.

in 2004, PG&E used ILI to inspect an average of 123 miles per year in 2005-2008.[123] But PG&E in-line inspected only an average of 21 miles of pipeline per year in 2009-2011.

PG&E has no explanation for why it reduced its reliance on ILI for assessing pipelines with manufacturing threats.

The likely conclusion is that the decrease in ILI after 2008 corresponded to a change in FERC accounting rules. Based on FERC guidance, starting in 2008 PG&E accounted for ILI costs as an expense, rather than a capital cost.[124] This means that capital work associated with retrofit and ILI would not have contributed to PG&E's rate base and profits.

PG&E was obligated to perform the work necessary to maintain a safe and reliable system, regardless of how much it cost or whether it contributed to rate base. It is not an indication of prudent management if PG&E spent the amounts it had forecast, but managed to defer projects and, at least in one category of MWC-75 spending on transmission reliability in 2009, complete only three-quarters of the work it had forecast to perform.

VI. OTHER ALLEGATIONS RAISED BY TESTIMONY OF TURN

TURN presented its own testimony that, among other things, supplemented and expanded upon CPSD's demonstration of PG&E's serious integrity management violations.[125] Because it closely relates to CPSD's showing, much of TURN's testimony is incorporated into the discussion in Section V.B above. Here, TURN summarizes some of the main points of that testimony, particularly TURN's showing that PG&E's violations affected much more pipeline than just Segment 180 and Line 132.

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[123] This number reflects the fact that PG&E ILI'ed much pipeline not in HCA locations. In total, PG&E ILI'ed approximately 826 miles of pipeline in 2000-2011, of which approximately 170 miles was HCA pipeline (the numbers are not entirely consistent due to different years reported in different testimonies/data responses).
[124] Exh. TURN-1, p. 16:14-16, Hawiger/TURN; See, also, Exh. CPSD-168, p. 7-6 to 7-7.
[125] Exh. TURN-1 (Hawiger).

A. PG&E Violated Federal Regulations and PU Code 451 by Repeatedly Spiking Multiple Pipelines and Failing to Properly Assess Those Pipelines

As discussed in Section V.B above, PG&E deliberately spiked over 415 miles of pipeline on twelve different pipelines.[126] PG&E identified manufacturing threats to exist on at least 86 miles of the spiked pipeline.[127] PG&E included 51.7 miles of that pipeline in the PSEP Phase 1 for testing (31.9 miles) or replacement (19.8 miles), presumably due to the lack of any documentation of prior strength testing.[128] This represents a potential ratepayer cost of approximately $100 million.

PG&E should have at a minimum hydrotested the 86 miles of spiked pipeline with identified manufacturing threats as part of its integrity management program. As discussed in Section V.B, such testing was required pursuant to the explicit language of Section 192.917(e)(3). Moreover, the extent of PG&E's deliberate pressure spiking (occurring fifteen times over a period of seven years) warrants a finding that PG&E violated PU Code 451 by engaging in an unsafe practice with the explicit intent of evading federal requirements to hydrotest pipeline with pressure excursions.

TURN will recommend in its fines and remedies brief that PG&E should be responsible for the cost of testing or replacing all of this pipeline, including the 51.7 miles included in Phase 1 of the PSEP.

B. PG&E May Have Violated Federal Regulations By Relying on ECDA to Assess the Majority of the Pipelines with Identified Manufacturing Threats

The focus on the CPSD and NTSB Reports is on Line 132; however, the Reports clearly show that the identified problems impact PG&E's entire integrity management program and

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[126] Exh. TURN-1, p. 19, Hawiger.
[127] Exh. TURN-1, p. 19. Based on the 2009 BAP.
[128] The remaining 34.3 miles are included in the PSEP Phase II.

were not limited to Line 132. These failings were summarized in Section V.B of this brief. The NTSB concluded that the "PG&E gas transmission integrity management program was deficient and ineffective" and recommended that PG&E "assess every aspect of your integrity management program."[129]

The NTSB Report notes that all of Line 132 was assessed exclusively with ECDA. The NTSB Report further notes that of the 1,021 miles of HCA pipeline, 813 miles were designated for assessment with ECDA and 208 miles *were designated for assessment* with ILI. None were designated for assessment with hydrotesting.[130]

TURN's testimony showed that PG&E's failure to properly assess its pipe with manufacturing threats extended well beyond Line 132. More specifically, TURN showed that in its 2009 Baseline Assessment Plan (" 2004 BAP") PG&E identified 400 miles of HCA pipeline as having potential seam or non-seam manufacturing threats, based on procedures detailed in its 2004 RMP-06 document.[131] By the time of the San Bruno explosion, PG&E had classified only 11.15 miles of pipeline with manufacturing threats as unstable and requiring assessment.[132] PG&E has apparently revised its estimate since the explosion and now classifies 46 miles of pipeline as having an unstable manufacturing or construction defect.[133]

By the end of 2010, PG&E had assessed 357 miles of the 400 (2009 number) miles of pipeline with manufacturing threats. PG&E assessed 322.95 miles of this pipeline using external

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[129] Exh. CPSD-9, p. 114.

[130] Exh. CPSD-9, NTSB Report, p 112. PG&E's numbers in testimony differ somewhat, perhaps due to the use of a different time period. During 2002-2010 PG&E assessed 649 miles of HCA pipeline using direct assessment, 171 miles using ILI and only 14 miles using hydrotesting. Exh. TURN-1, p. 16:10-11, Hawiger.

[131] PG&E had identified 457 miles with manufacturing threats in its 2004 BAP, but PG&E reclassified some of the pipeline as distribution or non-HCA, resulting in 400 miles with MT in its 2009 BAP. Exh. TURN-1, p. 10-11.

[132] Exh. CCSF-1, p. 8:21-24, Gawronski.

[133] Exh. CCSF-1, p. 10, A.20 and A.21, Gawronski.

corrosion direct assessment ("ECDA").[134] PG&E assessed only 34.35 miles using in-line inspection, including only 10.41 miles using TFI pigging.[135] As discussed in Section V.B. above, it is undisputed that ECDA is not an appropriate assessment method for unstable manufacturing threats.

Of the 400 miles of pipeline with identified manufacturing threats, 301 miles are included either for testing (239 miles) or replacement (52 miles) in the Phase 1 PSEP. This suggests that these 301 miles are missing evidence of a post installation hydrotest.[136] It is thus likely that PG&E should have considered the manufacturing threat for some or all of these 300 miles to be unstable, and should have conducted hydrotests or ILI instead of ECDA on this pipeline.

Based on the record of this case and I.11-02-016, TURN intends to provide recommendations in the fines and remedies brief concerning the remedies and actions that the Commission should adopt related to this pipeline.

VII. OTHER ISSUES RAISED BY TESTIMONY OF CCSF

At this time, TURN has no issues to discuss in this section of the brief that have not been discussed elsewhere, but reserves the right in its reply brief to address issues raised by other parties.

VIII. OTHER ALLEGATIONS RAISED BY TESTIMONY OF CITY OF SAN BRUNO

At this time, TURN has no issues to discuss in this section of the brief that have not been discussed elsewhere, but reserves the right in its reply brief to address issues raised by other parties.

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[134] Exh. TURN-1, p. 14:1-3, Hawiger.
[135] Exh. TURN-1, p. 16:17-19, Hawiger. Transverse Field Inspection is an ILI tool capable of detecting seam anomalies.
[136] Under D.11-06-017, the PSEP plans were only required to address pipeline for which the utility lacked a valid pressure test record.

IX. CONCLUSION

The record in this proceeding demonstrates numerous and serious PG&E violations of Section 451 and the federal pipeline safety regulations. Because of the importance of the Commission's conclusions in this case to current and future PSEP ratemaking, in the event the Commission does not find that CPSD and intervenors have not met their burden of demonstrating that particular conduct constitutes a violation, the Commission should determine whether PG&E has met its burden of showing the reasonableness of its actions.

Date: March 11, 2013

Respectfully submitted,

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