PACIFIC GAS AND ELECTRIC COMPANY
San Bruno GT Line Rupture Investigation
Data Response

PG&E Data Request No.:	CPUC_100-03		
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		Requester:	Eugene Cadenasso

QUESTION 3

Since the beginning of the GPRP to the present, does/did it involve the repair, replacement, and other activities identified in Item # 2 of both gas distribution and transmission pipelines? If not, explain:

a) when the program was changed;

b) why the program was changed, and;

c) what PG&E program(s) involves transmission pipeline repairs, replacements, and other activities identified in Item # 2 from the time the change occurred to the present. Indicate if a formal PG&E program does not exist for these activities.

ANSWER 3

From its inception in 1985 through 1999, the GPRP covered both gas distribution and gas transmission pipelines that met the criteria for inclusion in the GPRP. The distribution portion of the original program targeted the replacement of cast iron main and pre-1931 steel distribution main. The transmission portion of the GPRP targeted the replacement of pipe with girth weld types known to experience high stress failure. This included segments containing oxy-acetelyne gas welds or unshielded electric arc welds. The program evolved over the years in terms of scope (which pipe was included) and the methodology used for prioritizing pipe replacement.

In 2000, the remaining transmission pipeline in the GPRP was removed from the GPRP and transitioned to the Gas Transmission Risk Management Program (RMP). PG&E initiated the RMP to supplement and improve operational processes relating to managing transmission system risks. Unlike the GPRP, the RMP was designed to assess and prioritize the risk of all transmission pipelines, regardless of age, and to identify and implement a variety of targeted risk reduction activities, not only replacement or retirement. The transition to a risk management program was intended to facilitate the efficient use of available financial resources to reduce overall gas transmission system risk. Furthermore, PG&E's transition to a risk management approach for its transmission system aligned with the direction in which PHMSA was heading, culminating in the adoption in 2003 of the integrity management rule in 49 C.F.R. Part 192, Subpart O.

PG&E's Risk Management Program covers a variety of pipeline safety and maintenance related work. Going back to 2000, the RMP covered work such as in-line inspections (ILI); preparing pipelines for ILI; deactivating or replacing pipeline; upgrading regulator stations; seismic retrofits; direct assessments (ECDA); indirect corrosion surveys; and efforts to prevent third party damage.

With the adoption of the integrity management rule in 2003, PG&E began its Transmission Integrity Management Program (TIMP) in 2004. As part of TIMP, PG&E undertook an analysis to determine which transmission pipelines were covered by the integrity management rule by virtue of being located in a High Consequence Area (HCA) and prepared a plan to assess the covered transmission pipelines based on risk priority. Because TIMP covers only pipe within an HCA, it does not apply to well over half of PG&E's transmission system. With the implementation of TIMP in 2004, PG&E continued voluntary risk reduction projects on the remainder of its transmission system under the ongoing RMP.

PG&E's spending on gas transmission pipeline safety and maintenance work (including TIMP and the RMP) is tracked in a variety of major work categories. As reflected in the most recent GT&S Rate Case, these currently include:

- Pipeline Integrity Management—Capital (MWC 98) covers capital expenditures for TIMP, including, in particular, retrofit work to prepare pipelines for ILI. The replacement of any pipeline within an HCA or elsewhere on PG&E's gas transmission system is included within MWC 75 (below).

- Pipeline Safety and Reliability—Capital (MWC 75) covers a broad range of capital expenditures to improve the safety and reliability of the gas transmission system. This includes pipeline replacement under the RMP and the replacement of pipeline within an HCA; all other capital expenditures for the RMP (e.g. preparing non-HCA pipes for ILI); cathodic protection (e.g., replacing deteriorated or failed pipeline coatings); replacing equipment within gas regulator stations; and other pipeline reliability projects.

- Pipeline Integrity Management—Expense (MWC II) covers the expense portion of TIMP, including the cost of assessments and re-assessments using ILI, direct assessment (ECDA), or pressure testing.

- Gas Transmission System Maintenance—Expense (MWC BX) covers a wide variety of safety and maintenance-related expenditures, including the expense portion of the RMP as well as other transmission pipeline, compressor, and storage field maintenance work.

- Mark and Locate—Expense (MWC DF) covers the costs associated with marking and locating gas transmission facilities to protect against third party dig-ins and the costs for standby activities during third party excavations in close proximity to gas transmission lines.

These work categories are described in detail in PG&E's 2011 Gas Accord submission, Chapters 5 and 6. This list does not include pipeline work to increase capacity or to respond to customer requests.