From: Redacted
Sent: 8/1/2014 11:53:01 AM
To: bishu.chatterjee@cpuc.ca.gov (bishu.chatterjee@cpuc.ca.gov)
Cc: Doll, Laura (/O=PG&E/OU=CORPORATE/CN=RECIPIENTS/CN=LRDD)
Bcc:
Subject: Response to your 4/1/14 Data Request - #5030

Bishu,

Please see below PG&E's responses to your April 1, 2014 data request.

PG&E is providing this response pursuant to Public Utilities Code §583 because this response and/or the attached documents contain information that should remain confidential and not be subject to public disclosure as it contains one or more of the following: critical infrastructure information that is not normally provided to the general public, the dissemination of which poses public safety risks (pursuant to the Critical Infrastructures Information Act of 2002, 6 U.S.C. §§131-134); personal information pertaining to PG&E employees below director level; customer information; or commercially sensitive/proprietary information.

QUESTION 5030.01: Please provide all current standards, procedures, instructions, bulletins, guides, policies, documents, etc. that address how internal corrosion in gas pipes are identified, classified, and repaired in your Gas Transmission System. For a period of one year from the date of this request, please provide one copy of any of the above documents, whenever they are revised.

RESPONSE 5030.01: PG&E recently published new internal corrosion guidance documents, consisting of one new internal corrosion control standard and five new internal corrosion control procedures. The newly published internal corrosion control documents are attached as:

"TD-4186S_CONF.pdf"

"TD-4186P-100_CONF.pdf"

"TD-4186P-200_CONF.pdf"

"TD-4186P-300_CONF.pdf"

"TD-4186P-400_CONF.pdf"

"TD-4186P-500_CONF.pdf"

These documents have an 18 month implementation period to allow time for any necessary training, communication, and full system wide implementation. Until the new documents are effective in January 2016, PG&E's existing standard (attached as "*O-16_CONF.pdf*") that addresses internal corrosion will remain in effect.

QUESTION 5030.02: How many miles of gas transmission lines do you have in your system?

RESPONSE 5030.02: As reported in PG&E's Annual Reports to PHMSA (Form 7100) for calendar year 2013, PG&E currently has approximately 5,737 miles of gas transmission pipelines, and 54.7 miles of Standard Pacific Gas Line Inc. (StanPac) natural gas transmission pipelines.

QUESTION 5030.03: What percent of incidents in gas pipeline took place due to internal corrosion in the last 20-year period from 1994 through 2014? External corrosion from 1994 to 2014?

RESPONSE 5030.03: See PG&E's response in the 2015 GT&S Rate Case proceeding, attached as "*GTS-RateCase2015_DR_TURN_009-Q10.pdf.*"

QUESTION 5030.04: What percent of all incidents resulted from the gas pipeline internal corrosion?

RESPONSE 5030.04: See PG&E's response in the 2015 GT&S Rate Case proceeding, attached as "*GTS-RateCase2015_DR_TURN_009-Q10.pdf.*"

QUESTION 5030.05: What mitigation measures do you follow to mitigate the internal corrosion hazard in your gas transmission pipelines?

RESPONSE 5030.05: Currently, PG&E uses gas dehydration, liquid removal, select inhibitor injection, and pig cleaning on ILI projects and ICDA projects to mitigate internal corrosion. Biocide injection and maintenance pigging will be considered as part of future mitigation practices.

QUESTION 5030.06: Please describe the process you use to identify and then repair internal corrosion?

RESPONSE 5030.06: Please refer to attachment "*O-16_CONF.pdf*" for a description of the process PG&E currently uses to identify and repair internal corrosion. Please refer to the new internal corrosion standard and procedures attached to Question 1 above that will be effective in 2016.

QUESTION 5030.07: During the years 2000 to 2013 how many internal corrosion did you repair (by year)?

RESPONSE 5030.07: Please refer to the following table for the list of internal corrosion leaks repaired on gas transmission pipelines from 2000 through 2013.

Year	**Number of Internal Corrosion Leaks Repaired on Gas Transmission Pipelines**
2000	3
2001	4
2002	4
2003	2
2004	1
2005	2
2006	3
2007	4
2008	4
2009	1
2010	1
2011	0
2012	1
2013	2
Total	**32**

QUESTION 5030.08: During the years 2000 to 2013 how many internal corrosion did you have in each of your class locations, including High Concentration Areas?

RESPONSE 5030.08: PG&E records show the 32 internal corrosion leak repairs on gas transmission pipelines from 2000 through 2013 were all in Class 1 locations, none of which were in High Consequence Areas.

QUESTION 5030.09: Please thoroughly describe PG&E's corrosion control program and its design to detect, prevent, and control internal corrosion within the gas transmission system.

RESPONSE 5030.09: Please refer to PG&E's response to Question 1 above.

QUESTION 5030.10: Does PG&E conduct chemical and microbial analysis along its pipeline? If so please describe.

RESPONSE 5030.10: Yes, PG&E conducts analysis for moisture content, carbon dioxide, and hydrogen sulfide at most locations where PG&E interconnects with upstream gas supplies. Microbial analysis is performed at select locations downstream of gas gathering lines and on drip samples.

QUESTION 5030.11: How confident is PG&E that it's not transporting corrosive gas in its transmission system?

RESPONSE 5030.11: Natural gas transported in PG&E's transmission system is not considered corrosive as long as its meets the criteria specified in PG&E's Transportation Tariff, Rule 21, Section C, on Gas Quality. This section places limits on the acceptable quantity of each component that could cause the natural gas to be corrosive, specifically for carbon dioxide ($CO2$), hydrogen sulfide ($H2S$), water vapor, and total sulfur. To ensure these limits are enforced, PG&E continually monitors the quality of gas at all major receipt points into its system. The data from these monitors is sent to Gas Control, via the SCADA system, where alarms are activated when the limits are approached. These alarms are then evaluated for corrective action, as necessary.

For the large interconnects and storage fields (except Pleasant Creek), PG&E utilizes gas chromatographs (GC's) to continually monitor the gas composition including the CO2 concentration. For the third party operated California production and the Pleasant Creek Storage Field, the supply gas is collected continuously using a time-weighted sampler which allows PG&E to analyze the gas and determine the average CO2 concentration at the receipt points. The Interconnects between PG&E and SoCal

Gas and Southwest Gas are not monitored for quality because the flow rates are relatively small or infrequent. Often the gas flow originated from PG&E toward SoCal Gas or Southwest Gas, or the gas is from a transmission line that has already been monitored for quality.

Water vapor, H2S, and Total Sulfur analyses are handled somewhat differently as described below. Some analyses are performed at the receipt points to PG&E and some are done downstream within the PG&E system.

- Water vapor - PG&E continuously measures the water vapor content of the collective Transwestern, El Paso, Kern River Daggett, and Questar supplies at the Hinkley Compressor Station discharge on both Lines 300A and 300B. PG&E continuously monitors the water vapor content of the combined Ruby/GTN gas at the Burney Compressor Station on both Lines 400 and 401. The moisture content of the Ruby supply is also monitored by the supplier at the interconnection to PG&E and the live data are sent to PG&E's SCADA system. PG&E also continuously monitors the water vapor content of gas received from all of the third party storage fields and the two largest PG&E storage fields, and at five different locations within the PG&E system. The moisture content of the California production is monitored periodically (weekly or monthly) using stain tubes or a Chanscope. If the H2O levels are above the Rule 21 limit of 7 lbs./MMSCF, then the producer is shut-in until the level is returned to below the limit.

- H2S, and Total Sulfur - PG&E continuously monitors the H2S and Total Sulfur level of gas in Lines 300A and 300B at the Topock plant discharge and at the Hinkley Compressor Station suction, and in Lines 400 and 401 at the Burney Compressor Station. The monitors used by PG&E are Medor sulfur chromatographs. PG&E also monitors the H2S and Total Sulfur levels of gas leaving and entering all of the third party storage fields, the two largest PG&E storage fields, and at various locations within PG&E. The H2S and Total Sulfur levels of the GTN and Ruby supplies are monitored by these suppliers at the interconnection and the live data are sent to PG&E's SCADA system.

PG&E has found that exceedances of the carbon dioxide, hydrogen sulfide, and total sulfur limits are extremely rare. The water vapor limit is occasionally exceeded; if it is, PG&E takes immediate steps to shut-in the source of the high moisture gas and take action to mitigate any potential effects.

QUESTION 5030.12: Identify any and all areas by line and segment number where PG&E has reduced operating pressure in accordance with 49CFR192.485 due to localized internal corrosion pitting and any associated reduction in wall thickness.

RESPONSE 5030.12: PG&E's records do not indicate any instances of pressure reductions in accordance with 49CFR192.485 due to internal corrosion findings.

QUESTION 5030.13: How does PG&E identify the low points throughout their system where fluids are likely to accumulate and how does PG&E identify how to remove the fluids from the lines?

RESPONSE 5030.13: PG&E utilizes as-built data, pipe depth measurements, and terrain contour to identify low points throughout its system. PG&E uses historic inspection data, liquids testing, and gas quality information to identify where there is a likelihood of liquids in the transmission pipeline and where there is an internal corrosion risk. The gas pipelines are then ranked across the system for risk and then scheduled for ILI upgrades and subsequent ILI cleaning runs, or an ICDA inspection and mitigation. In addition, PG&E has liquid removal locations installed throughout the gas transmission system to remove any identified liquids.

QUESTION 5030.14: How does PG&E address fluid accumulation in unpiggable lines?

RESPONSE 5030.14: The first line of defense PG&E uses to address fluid accumulation in unpiggable lines is to remove liquid at the source by filtering and performing gas quality monitoring. Additionally, gas quality parameters are enforced at receipt points. For occasional liquid upsets, drips are located at select low points suspected to collect liquids. Also, filter units are located at regulator stations to remove liquids moving through the transmission system before they enter the distribution system.

QUESTION 5030.15: Please provide any and all PG&E internal reports on internal corrosion hazard on its transmission system including any reports that evaluate flow velocities, low spots in pipelines, drips, vessels, gas quality analysis, liquid analysis and any maintenance history and specifies and or follow-up remedial actions.

RESPONSE 5030.15: Due to the potential expansiveness of this request, PG&E will schedule a meeting with the CPUC to discuss the scope.

QUESTION 5030.16: Please state what percent of your transmission pipeline is identified to be piggable?

RESPONSE 5030.16: Approximately 25% of PG&E's 5,737 miles of gas transmission pipelines are currently piggable.

QUESTION 5030.17: Please describe if you use any of the following preventive/mitigation measure to address your transmission gas pipeline internal corrosion:

Dehydration

Inhibitors

Coatings

Buffering

Cleaning Pigs

Biocides

RESPONSE 5030.17:

Dehydration	Used in gas gathering and storage
Inhibitors	Minimally used in gas gathering areas
Coatings	Not used to prevent internal corrosion
Buffering	Not used to prevent internal corrosion
Cleaning Pigs	Cleaning pigs are typically used before ILI projects and are not currently used on a maintenance basis to prevent internal corrosion.
Biocides	Not currently used to prevent internal corrosion

QUESTION 5030.18: Please provide a table of any and all transmission line segments in High Consequence Areas, with GPS location where PG&E has determined or suspects that internal corrosion is anticipated to be present and what monitoring or remedial activities are in place at those areas.

RESPONSE 5030.18: Please see attachment "*IC Threat Locations_2013_CONF.xlsx*" for a list of gas transmission pipeline segment and station locations in HCAs where PG&E has determined or suspects that internal corrosion may be present and where PG&E's assessment plan includes internal corrosion assessments to investigate those locations.

Sincerely,

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From: Chatterjee, Bishu [mailto:bishu.chatterjee@cpuc.ca.gov]
Sent: Monday, May 05, 2014 12:03 PM Pacific Standard Time
To: Doll, Laura
Subject: RE: CPUC Data Requests Internal Corrosion

Hi Laura – I was wondering whether PG&E has already send me the response to this data request? I do not find it in my email. I wonder if it was sent back under a different name? Can you please confirm? Thank you.

Bishu Chatterjee, PhD

Risk Assessment Unit, SED

California Public Utilities Commission

415 703 1247

bbc@cpuc.ca.gov

From: Chatterjee, Bishu
Sent: Tuesday, April 01, 2014 5:31 PM
To: Redacted
Cc: Bruno, Kenneth
Subject: CPUC Data Requests Internal Corrosion

This message's contents have been archived by the Barracuda Message Archiver.
Gas Transmission Data Request (IC Report) PGE_April12014.docx (36.5K)

Hello Laura – I am sending you the attached data requests on Internal Corrosion.

Please let me know if you have any questions. Thank you,

Bishu Chatterjee, PhD

Risk Assessment Unit, SED

California Public Utilities Commission

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