The DEIR should be corrected as follows to reflect the correct pipe grade: S-83

> . . . A large proportion of the proposed pipeline would consist of 0.375-inch-wall thickness steel pipe (Grade X-~~60~~ 65) designed for a Maximum Allowable Operating Pressure (MAOP) of 975 pounds per square inch gauge (psig). . . .

Corrosion Mitigation **Page 4.7-37, lines 12-17 (MM HAZ-2a)**

PG&E strongly disagrees with the requirement to perform a baseline smart pig inspection within the first six months of placing the pipeline into operation. PG&E's Integrity Management plan, in full compliance with the State of California's General Order 112E and 49 CFR Part 192.921 Subpart O, states that newly installed pipe that are HCA's or newly identified HCA's must be scheduled for assessment within 10 years from the date the pipe is installed or the new HCA identified. For new pipe, a post-installation pressure test per subpart J of 192 should be used as the baseline assessment. Therefore, PG&E proposes the following modification; S-84

> PG&E shall prepare and implement an Operation and Maintenance Plan in accordance with the requirements in Title 49 CFR part 192. The plan shall include a post installation pressure test per 192 subpart J ~~Within the first 6 months of placing the pipeline into operation, PG&E shall conduct a baseline internal inspection with a high resolution instrument (smart pig) of the pipeline~~ in order to obtain baseline data for the pipeline.

Corrosion Mitigation **Page 4.7-37, lines 18-23 (MM HAZ-2a)**

PG&E takes exception to this section of MM HAZ-2a as it relates to baseline inspections and intervals. The DEIR's proposed inspection requirements are unwarranted under the federal law cited by the DEIR in their request for ILI inspections. Additionally, by focusing limited state authorized funding for discretionary pipeline inspections on our newest pipeline, the DEIR's proposal will have the unintended consequence of increasing risk on the rest of our transmission system.

The proposed requirements are unwarranted because there is no requirement in the cited 49 CFR Part 192 to perform regular subpart O assessments of pipelines in non HCA areas. There is no requirement in 49 CFR Part 192 to perform assessments of HCA area piping within 6 months of identification of an HCA. There is no requirement in 49 CFR Part 192 to perform an assessment within 6 months of another assessment (PG&E's pressure testing of the line prior to placing it into service will meet the assessment requirements of 49 CFR Part 192) It is a violation of 49 CFR Part 192 to select an assessment technology for HCA assessments without regard for the potential threats as the DEIR proposes. 49 CFR §192.921 requires "An operator to select the methods best suited to address the threats identified to the covered segment." S-85

Only a few very small areas around the proposed pipelines meet the requirements of high consequence areas as defined by 49 CFR §192.903 method 2. Other inspections of this pipeline are discretionary. Non-mandatory inspections of at risk lines are authorized by the state through a program that focuses on the most at risk pipelines within the PG&E system. The program funding is also authorized by the state, but it is not unlimited. These brand new line pipelines are clearly and obviously not the most at risk lines within the PG&E system. By using the limited funding available for non mandatory inspections to assess brand new pipelines, the DEIR is increasing the risk of failure for older, more at risk pipelines. S-85 Cont.

Installation of Automatic Shutdown Valves Page 4.7-38, lines 10-20 (MM HAZ-2b)

The proposed mitigation measure requires PG&E to install Automatic Shutdown Valves in three locations. PG&E has evaluated the use of remote control valves and automatic shut-off valves (RCV-ASV) as required by code section (§192.935(c)) for any high consequence areas, which states:

> (c) *Automatic shut-off valves (ASV) or Remote control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, threat of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

After completing the review, PG&E agrees that installing such valves may be an efficient means of adding protection. However, PG&E strongly believes that using RCV's rather the ASV's is a better approach. Use of ASV's does not yield any additional protection beyond that realized by RCV's, and ASV's pose a concern of an unintended closure, which could lead to greater safety and reliability problems. S-86

Lines 406 and 407 are part of a transmission pipeline network, which experiences a wide range of flow and pressure variations during normal operations. Since an ASV's are programmed to operate based upon flow and or pressure variations, the ASV could operate during normal conditions, causing an unplanned outage of customers in Yolo, Sacramento, El Dorado, Placer, Sutter, Yuba, and Nevada counties served by the proposed project. Large outages present the threat of customers relighting their own pilots, which could result in higher risks resulting from improper re-lights by customers

Additionally, activation of an ACV limits the response scenarios available to PG&E. With RCV's, PG&E personnel can lower the operating pressure of the pipeline to reduce the threat of damage while activating alternative supplies. PG&E can also provide temporary supplies downstream of the incident that could support customers, and then shut down the line after these supplies are in place. If the pipeline must be shut down, deferring this shutdown for a short period of time is sometimes prudent so that customers can be shut down in an orderly and safe manner.

Based upon the above, PG&E suggests the following changes.

> PG&E plans to install remote operated valves at the Capay Station and the Yolo Junction Station, which would help to control the flow of gas into Lines 406 and 407. PG&E shall install ~~automatic~~ remote operated shutdown valves in three locations: Power Line Road MLV Station No. 752+00 (which includes the Riego Road Regulating Station), Baseline Road/Brewer Road MLV Station No. 1107+00, and Baseline Road Pressure Regulating Station No. 1361+00. These ~~automatic~~ remote operated shut

down valve locations would enhance public safety protection in the planned populated areas, which include schools and other existing and planned developments. S-86 Cont.

SECTION 4.8 HYDROLOGY AND WATER QUALITY

Unanticipated Release of Drilling Fluids **Page 4.8-18, line 17 (MM HWQ-1)**

The DEIR requires PG&E to monitor turbidity downstream of the drill site. PG&E is required to obtain a permit from the Regional Water Quality Control Board, which will specify the required monitoring. Therefore, PG&E suggests the following modification to this mitigation measure: S-87

> Monitor water quality including turbidity in accordance with applicable Regional Water Quality Control Board permits. ~~downstream of the drill site~~

Unanticipated Release of Drilling Fluids **Page 4.8-18, lines 25-26 (MM HWQ-1)**

The DEIR requires PG&E to use non-toxic fluorescent dye in the drilling mud to allow easier identification of frac-outs." However, drilling fluid is often used by farmers as an additive to their soils, and the addition of fluorescent dye will render the drilling fluid unusable to the farmers. Therefore, PG&E requests that this requirement be deleted. S-88

Verify Well Locations **Page 4.8-20, lines 18-31 (MM HWQ-2)**

The DEIR contains a mitigation measure to protect the supply of water in the vicinity of construction. PG&E suggests that this mitigation measure be modified as follows to enable PG&E to use a professional hydrogeologist to identify wells that need to be tested. S-89

> Prior to construction of the proposed Project, well locations within 200 feet of the excavation, construction staging areas, and aboveground facility locations shall be verified by PG&E through field surveys to determine if private water wells and water pipelines are currently in use and if their area of influence intersects the proposed Project site. This survey will be conducted by a licensed professional Hydrogeologist, who will determine any potential impacts from construction. Based on his professional opinion, wells will be tested as needed. ~~With the landowner's permission, PG&E shall test the wells to determine the baseline flow conditions and monitor these wells during construction of the proposed Project.~~ If, through monitoring, it is determined that Project construction is affecting well production, PG&E shall cease construction activities or arrange to supply water at the well location and consult with the landowner. Surveys shall be conducted by PG&E prior to construction to ensure that any unidentified springs are avoided during construction.

Flood-Proof Facilities **Pages 4.8-21, line 23, to 4.8-22, line 2 (HWQ-3)**
Page 4.8-34, lines 30-34; Page 4.1-13, lines 15-18

The DEIR requires PG&E to place any pump stations and valve housing that are located within the 100-year flood zone at least 1 foot above the 100-year storm floor profile level. Because the stations have been designed to prevent an overpressure of the pipeline system in the event of a flood, PG&E requests that the requirement for elevating structures be S-90 deleted. The text of the HWQ-3 should be modified, along with corresponding changes in chapter 4.1: S-90 Cont.

Pages 4.8-21, line 23, to 4.8-22, line 2

. . . Mitigation is proposed below to flood-proof any structures proposed to be constructed within a 100-year floodplain. Both proposed structures would be no more than 10 feet in height ~~without the flood-proofing. Flood-proofing would require the structures to be raised approximately 1 foot above the 100-year storm flood profile level~~.

Mitigation Measures for Impact HWQ-3: 100-Year Floodplain

MM HWQ-3 Flood-Proof Pump Houses Within 100-Year Floodplain. If any structures (pump stations, aboveground valve housing) associated with the buried pipeline are placed within the 100-year flood zone, the structure shall be "flood-proofed" in their ~~foundation~~ design ~~and raised in elevation to a minimum of 1 foot above the 100-year storm flood profile level,~~ to reduce the risk that they would be damaged during such an event. S-91

Page 4.8-34, lines 30-34

. . . MM HWQ-3 would require the flood proofing of any structures associated with the above ground stations~~, including but not limited to, the elevation of structures to 1-foot above the 100-year storm flood profile level~~. Implementation of MM HWQ-3 in both the proposed project and Option H would reduce impacts to less than significant. S-92

Page 4.1-13, lines 15-18

Regulating Station and the Powerline Road Main Line Valve structures would be constructed within the 100-year floodplain and would be no more than 10 feet in height ~~without the flood-proofing. The mitigation requires that the structures be raised approximately 1 foot above the 100-year storm flood profile level~~. S-93

Thank you for the opportunity to comment on this DEIR. If you have any questions or would like to discuss these comments please contact me at your convenience.

Sincerely,

Chris Ellis

Chris Ellis, AICP
Principal Planner
Pacific Gas and Electric Company

Enclosure

{00083310.DOC;1}

Kiefner & Associates, Inc.

June 12, 2009

Mr. Scott Clapp
Gas Transmission Systems
130 Amber Grove Drive, Suite 134
Chico, California 95973

Re: Review of EIR for PG&E Lines 406 & 407

Dear Mr. Clapp:

In accordance with your request, I have reviewed certain documents that are part of the Draft Environmental Impact Report (EIR) for Pacific Gas & Electric (PG&E) Lines 406 and 407 proposed for construction between Esparta, Yolo County and Roseville, Placer County, CA. Lines 406 and 407 are to be constructed from 30-inch OD line pipe and will transport natural gas at a pressure of 975 psig. The pipeline route will cross primarily Location Class 1 (rural) areas, although it will also traverse Location Class 2 and Class 3 areas having greater amounts of development in the vicinity of the pipeline. The Location Classes are determined by the amount of land development in the vicinity of the pipeline as defined by Federal pipeline regulations contained in Code of Federal Regulations Title 49 – Transportation, Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards (49, CFR 192, or "Part 192"). The intrastate Lines 406 and 407 are under the jurisdiction of the California Public Utility Commission (CPUC) which has adopted 49 CFR 192 and enforces to its provisions. The pipelines will be designed, constructed, operated, and maintained accordingly.

The focus of my review was a risk assessment performed by EDM Services, Inc. Overall, I found that the results of the risk assessment were credible and not inconsistent with other risk assessments that have been performed by other parties concerning similar pipelines. However, I also discovered some data presented in EDM's analysis that was inconsistent with other sources of data, and some statements or opinions that I did not fully agree with and which reasonable people might hold a difference of opinion over. Although these variances in raw data or interpretation imply that some numerical results might change, these would not necessarily alter the overall conclusions or invalidate the assessment. S-94

The Table 1 below lists specific data presented, or statements made, in the Draft EIR dated April 13, 2009 and my comments in response. Additional tables summarize some data I used to evaluate EDM's analysis. S-95

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Table 1. Comments on the Draft EIR Risk Assessment

Reference page or section	**Comment**
Section 2.1.2 bottom of page 2	Add closing statement: "Other portions of the regulations are prescriptive."
Section 4.1.1, page 11	5,000 Btu/ft^2-hr, 1% mortality corresponds to 30 seconds unabated exposure. An able-bodied person would take actions to increase the separation distance or seek cover during that 30 seconds. 3,500 Btu/ft^2-hr, 10-second exposure does not correspond to 15% probability of fatality. According to Hymes (1983) a 45-second exposure corresponds to 1% mortality.
Section 4.1.2, page 13-14	Reference to 1970-1984 pipeline incident data is arguably not relevant because the data is 25-39 years old and standards and regulations for both new construction and the operation of existing lines have changed substantially. Changes are notable in the areas of fracture control for new pipe, routine use of ILI, adoption of damage prevention practices, and integrity management planning for high consequence areas, none of which were prevalent in 1970-1984.
Section 4.1.2, page 14-15	We get values that are close but not identical to those reported by EDM. For 1988-2008, we see 0.037 injuries and 0.0064 fatalities per 1,000 mi-yrs, compared with 0.040 and 0.010 reported on page 14 for 1986-2007. PHMSA's data web page for 1988 through 2008 tallies 382 "significant" incidents (same criteria as "reportable" incidents) for onshore gas transmission (323) and gathering (59) lines. This is much less than the 761 incidents stated on page 15 for 2002-2007. We get 0.18 incidents per 1,000 mi-yrs instead of the 0.42 incidents per 1,000 mi-yrs on page 16. However we get 0.019 injuries and 0.0033 fatalities, about the same as the 0.019 and 0.004 stated on page 15.
Figure 4.1.2-1, page 16	Using the tallies on PHMSA's data web page, the upper curve should vary between just above 0.10 and just below 0.30.
Page 17	We get 0.18 reportable incidents per 1,000 mi-yrs, not 0.29 for onshore gathering and transmission lines.
Pages 18-20	The US and CA hazardous liquid pipeline incident data may not be appropriate for evaluating the risk or threat associated with natural gas pipelines. Certainly pipelines in both categories are constructed from similar materials and to a layman would appear to present similar issues. However, they differ significantly in terms of operation, characteristics of transported products, failure modes, and consequences of a

S-95
Cont.

	failure.
Page 21	Many of the factors in the bulleted items can be reasonably attributed to features associated with older pipelines and construction methods. Frequencies of these factors should be adjusted to reflect rates of occurrence appropriate to the features of modern pipeline design and construction.
Page 23	The first paragraph provides for a 30% reduction in damage by outside forces based upon the added depth in the pipeline design. Additional reductions should be included to address other relevant issues such as resistance to immediate penetration from equipment afforded by the heavy wall thickness and large pipe used with this project, as well as the overall record of new large-OD pipe in Class 3 areas. Refer to discussion for Page 57, below.
Page 27	PG&E will be installing remote monitoring of cathodic protection potentials at approximately 1-mile intervals along the route. This will provide real time data of the cathodic protection system and allow for a timely response to make corrections. The risk of incident due to corrosion should be significantly reduced.
Pages 29-30	It is unclear why LPG pipelines are discussed (page 30). PHMSA's incident data for LPG pipelines are not intermixed with data for natural gas lines, nor are LPG pipelines part of the proposed construction. Does Table 4.1.3-2 (page 29) include LPG lines, and if so, why?
Page 30	The assertions that a release in an urban area is likely to cause more significant impacts to humans than a release in a rural area, and that the risk is understated for an urban area and overstated for a rural area both seem correct at first glance but appear to overlook some important factors. It is true that a worst-case scenario in an urban location would have greater consequences than a worst-case scenario in a rural location. But the probability of a worst-case scenario is greater in a rural location due to the higher operating stress levels and typically thinner wall pipe used in rural areas. It is noted for example that Class 3 lines comprise 11% of total gas pipeline mileage and 14% of gas pipeline reportable incidents, but there has only been one fatality caused by a Class 3 pipeline since 1989. Since 2002, there have been no fatalities in Class 3 or 4 and only one in Class 2. The heavier wall and lower operating stress does affect the susceptibility to failure and can affect its mode. Most major natural gas pipeline failures in the US have occurred in rural areas, e.g. Carlsbad. Also, Class 3 would automatically be designated a High Consequence Area (HCA)

S-95
Cont.

	and therefore would be subject to special integrity management planning rules that most portions of Class 1 and 2 lines would not be.
Baseline Frequency, page 31	We would use 0.18 incidents per 1,000 mi-yrs.
Indoor explosions, page 43	This does not reflect real modes of failure. Migration of gas to interiors of occupied buildings is primarily a concern with distribution piping systems which exist in close proximity and relatively low pressure. A leak at the operating pressure of 975 psig would blow a hole in the soil and vent the gas. Also, a leak would not tend to precede a rupture of the pipe.
Page 49, bottom of page	Statement that the "frequency of serious injuries or fatalities …are extremely low due to the rural areas..." implies that the expected frequency would be greater in the more developed areas which is not supported by the data.
Page 52, first full paragraph	Statement that "should population or traffic volumes increase…the likelihood of serious injuries and fatalities would increase accordingly" does not account for changes in pipe wall, HCA designation, and IMP activity that offset increased risk by reducing likelihood of an incident. Note zero fatalities in Class 3 and 4 areas.
Page 55, HAZ-1a	A stated mitigation is for pipe to be manufactured in year 2000 or later. 49 CFR 192 currently requires pipe to comply with 43^{rd} (2004) or 44^{th} (2008) editions of API 5L. Pipe mills currently only monogram pipe to 44^{th} Edition, so pipe must be 2008 vintage or newer. From a practical standpoint, it will be brand new pipe.
Page 57, third-party damage	30-inch OD x 0.375-inch WT X65 pipe provides resistance to immediate penetration by equipment at the 98^{th} percentile in terms of size or weight (about 73 T). The 0.500-inch WT specified for Class 3 areas would resist an even larger machine (120 T) that is not used in general construction. It is noted that the one fatal incident in Class 3 pipe that occurred in 1997 had 0.281-inch WT which is resistant to machines only up to 45 T which are more common.

S-95 Cont.

Some supporting data from PHMSA's website data summary page or downloadable data is summarized below. Table 2 summarizes "reportable" or "significant" incident data from 2002-2008 for natural gas onshore gathering and transmission (G&T) lines. Incidents for lines of all ages and sizes are reported. The average rate of occurrence per 1,000 mi-yrs is given at the bottom of the table. Also listed is a tally of those that occurred in post-1980 large pipe (20-inch OD and larger) and small pipe (smaller than 20-inch OD). Because national mileage could not be easily broken down by both size and age (either size or age is readily done but not both), no average rates per mile-year are shown. However, it is noted that post-1980 pipe comprises 27%

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of the total onshore G&T mileage, but the total number of incidents (50) and fatalities (1) in both post-1980 size ranges is only 13% and 14% of the total, respectively, indicating half the rate of occurrence for post-1980 pipe on a per mile-year basis. This reflects the improved technology associated with modern pipelines, relative to the aggregate US natural gas pipeline system which has a mileage-weighted average age of 40 years.

S-96 Cont.

Table 2. Natural Gas Onshore G&T Pipeline Incidents, 2002-2008, All and Post-1980

Year	All G&T pipe incidents			Post 1980, D=>20"			Post 1980, D<20"		
	Total	Fatalities	Injuries	Total	Fatalities	Injuries	Total	Fatalities	Injuries
2002	40	1	5	3	0	0	4	0	0
2003	62	1	8	3	0	0	6	0	0
2004	44	0	3	2	0	0	6	0	0
2005	68	0	7	0	0	0	2	0	0
2006	62	3	5	4	1*	0	3	0	0
2007	55	2	7	6	0	0	6	0	0
2008	54	0	5	0	0	**	5	0	**
TOTAL =>	385	7	40	18	1	0	32	0	0
Avg/yr =>	55.000	1.000	5.714	2.571	0.143	0.000	4.571	0.000	0.000
Avg/1000 mi-yr	0.1833	0.0033	0.0190						

*1982 vintage pipe
**4 injuries reported for post-1980 pipe but pipe size not stated

Table 3 below compares the occurrences of incidents for all ages and sizes of natural gas G&T pipelines from 2002 through 2008 sorted by Location Class. The proportionate representations of total system mileage of Location Classes 1, 2, 3, and 4 are 77.4%, 10.9%, 11.4%, and 0.3%, respectively. These proportions of system mileage were used to estimate average rates per 1,000 mile-years, shown below. It is apparent that rates of reportable incidents varies widely by class, but rates of fatalities in Class 1 and 2 are similar to each other, and rates of fatalities in Class 3 and 4 are low (zero in the sample period). A longer sampling period also shows near-zero fatality rates for Class 3 lines (there are no Class 4 lines in the proposed project). This illustrates the effectiveness of the risk-informed design basis for pipelines by Location Class, as well as the focus of integrity management planning on high-consequence areas.

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Table 3. Natural Gas Onshore G&T Pipeline Incidents, 2002-2008, by Location Class

Year	All Class 1			All Class 2			All Class 3			All Class 4		
	Total	Fatalities	Injuries	Total	Fatalities	Injuries	Total	Fatalities	Injuries	Total	Fatalities	Injuries
2002	31	1	2	2	0	0	7	0	1	0	0	0
2003	50	1	4	5	0	2	7	0	1	0	0	0
2004	32	0	2	5	0	0	7	0	1	1	0	0
2005	52	0	5	4	0	0	10	0	1	1	0	0
2006	47	3	3	5	0	1	8	0	1	0	0	0

2007	39	1	4	5	1	1	10	0	1	0	0	0
2008	40	0	5	1	0	0	2	0	0	1	0	0
TOTAL	291	6	25	27	1	4	51	0	6	3	0	0
Avg/yr	41.571	0.857	3.571	3.857	0.143	0.571	7.286	0.000	0.857	0.429	0.000	0.000
Avg/1000 mi-yr	0.1790	0.0037	0.0154	0.1198	0.0044	0.0178	0.2128	0.0000	0.0250	0.3106	0.0000	0.0000

S-97
Cont.

This concludes my review of the draft EIR for PG&E Lines 406 and 407. If you have further comments of questions, please feel free to contact me.

Sincerely,

Michael J. Rosenfeld, PE
President

RESPONSE TO COMMENT SET S

S-1 Comment acknowledged. Page ES-2, lines 13 through 15, of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-2 Comment acknowledged. Page ES-2, line 17, of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-3 The comment suggests that additional explanation for the rejection of Line 406 Central Alternative is needed. Additional text is inserted on page ES-4 of the Draft EIR in the middle of Line 22. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-4 The proposed additional text has been added to the Draft EIR on page ES-31 to clarify that the No Project Alternative would not meet the Project objectives. The CEQA Guidelines section 15126.6(e)(2) states that if the environmentally superior alternative is the "no project" alternative, then the EIR shall identify an environmentally superior alternative among the other alternatives. Furthermore, in response to comment P-10, text has been added to the Draft EIR on page ES-32, indicating that the incorporation of Options I and L would better promote the objectives of the Project than the proposed alignment or other options. Refer to Section 4.0 of this Draft EIR for revisions to the Draft EIR.

S-5 Comment acknowledged. Page 1-4, lines 21 through 23, of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-6 Comment acknowledged. Page 1-3, lines 4 through 5, of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-7 Comment acknowledged. Page 1-8, lines 28 through 29, of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-8 PG&E requested that the reclamation districts be removed from the list of permitting/approving agencies on page 1-8 of the Draft EIR. Upon contacting the reclamation districts, it has been understood that a PG&E representative has been in contact with the reclamation districts regarding required encroachment permits. The reclamation districts indicated that they did not want to move forward with the permitting until the EIR process was completed. Accordingly, the reclamation districts have not been removed from page 1-8 of the Draft EIR.

S-9 Comment acknowledged. Page 2-16, lines 3 through 5, and page 2-18, Table 2-2, of the Draft EIR have been revised to properly reflect that the DFM would be designed for a maximum allowable operating pressure (MAOP) of 975 psig. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

The sentence "Industry standards for pipeline sections installed via HDD technology require a pipe diameter to wall thickness ratio (D/t) of 50 or below," has not been removed because these are general guidelines that also need to be followed by PG&E.

S-10 Comment acknowledged. Table 2-1 on page 2-17 and Table 2-3 on page 2-49 of the Draft EIR have been revised to reflect the appropriate depth of the Sacramento River crossing. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-11 Comment acknowledged. Table 2-2 on page 2-18 of the Draft EIR has been revised to correctly reflect the DFM's attributes. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-12 Comment acknowledged. Page 2-31, line 18, and page 4.10-27, line 11 of the Draft EIR have been revised to correctly reflect the Yolo Junction Pressure Limiting Station height. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-13 Comment acknowledged. Page 2-37, line 1 through 3, of the Draft EIR has been revised. Figure 2-9 and Figure 2-10 have been relabeled. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-14 Comment acknowledged. Page 2-37 of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-15 Comment acknowledged. The following revisions have been made to reflect that deep-rooted plants would not be allowed to be planted within 10 feet of the pipeline centerline, rather than within 15 feet as stated in the Draft EIR: Page ES-2, line 19; Page 2-16, line 27; Page 2-37, line 20; Page 2-38, line 23; Page 4.1-14, line 4; Page 4.2-22, lines 22 through 23; and Page 4.2-24, line 29.

Because the planting limitation zone decreased in size, estimates of the acreage of affected agricultural land was recalculated and pages 4.2-24,lines 28 through 36; page 4.2-25, lines 1 through 15; page 4.2-31, line 14; page 4.9-18, lines 23 through 31; and page 4.9-31, lines 25 and 29, of the Draft EIR have been revised accordingly. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-16 Comment acknowledged. Page 2-37, line 26, and page 4.13-22, line 27, of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-17 Comment acknowledged. Page 2-49, lines 8 and 9, of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-18 Comment acknowledged. Page 2-55, lines 21 through 22, of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-19 Comment acknowledged. Page 2-55, lines 31 through 33, of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-20 Comment acknowledged. Page 2-71, lines 16 through 18, of the Draft EIR has been revised to provide the option of using slurry backfill instead of concrete coating in order to address the potential for scour, providing that methods are approved by a California licensed civil engineer. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-21 Comment acknowledged. Page 2-80, lines 11 through 23; page 3-59, lines 15 through 17; page 2-20, lines 18 through 19; and page 2-38, lines 8 through 12; of the Draft EIR have been revised to reflect the correct construction schedule.

The updated construction schedule affects the air quality analysis included in Section 4.3, Air Quality. Accordingly, page 4.3-38, lines 3 through 14, have been updated to explain that the construction schedule has changed, but the original construction period was used in the air quality analysis because it offers a more aggressive, worst-case scenario analysis. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

Furthermore, the following pages have been updated to indicate that continuous construction would take place at tie-in locations: Page 4.1-15, line 8; page 4.1-15, line 15 (MM AES-2); page 4.4-62 (APM BIO-8); Page 4.10-26, line 18 (APM NOI-2); page 4.10-34, lines 25 through 29; page 4.10-35, line 13 (MM NOI-1a); page 4.10-35, lines 24 through 27 (MM NOI-1b); page 4.10-36, lines 4 through 33 (MM NOI-1c); page 4.10-37, lines 12 through 15; page 4.10-40, line 19; and page 4.12-23, line 18. Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

S-22 Comment acknowledged. Page 2-83, lines 9 through 12, of the Draft EIR has been revised to better explain the locations at which GPS coordinates would be taken. The text was revised as requested, with the exception of requiring GPS coordinates at pipe welds. The new text indicates that GPS coordinates will be taken at a few reference pipeline welds. Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

S-23 Comment acknowledged. Page 2-84, lines 28 through 34, of the Draft EIR have been revised. Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

S-24 The CSLC acknowledges that, as a CPUC-regulated public utility, PG&E is not subject to local land use and zoning regulations, and is thereby not required to obtain local discretionary permits, including minor use permits. However, it is pertinent to disclose local jurisdiction regulations regarding the compatibility of the proposed pipeline and Williamson Act lands. As such, the first paragraph on page 4.2-19 has not been deleted. However, additional text has been added to page 4.2-19, line 2, of the Draft EIR in order to clarify PG&E's role as a CPUC-regulated public utility in regards to local land use and zoning regulations. Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

S-25 Please refer to response to comment M-6. A portion of the text in the Draft EIR has been revised to clarify measures PG&E will enact on spare the air days for APM AQ-11. Page 4.3-40 of the Draft EIR has been revised. Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

S-26 <u>While greenhouse gas (GHG) emissions would not be significant on a project level, they are considered to be cumulatively significant and require mitigation.</u> It is currently not feasible to calculate greenhouse gas (GHG) emission reductions achievable through compliance with fleet standards and the ARB's off-road in-use fleet rules. However, MM AQ-3 is applicable to actual impacts (projected impacts after incorporation of mitigation). As stated in the Draft EIR (refer to pages 4.3-51 and 4.3-52), APMs have the potential to reduce construction-generated GHGs. However, there are insufficient details and/or lack of methodologies to quantify the reductions. When quantification of those reductions becomes feasible, then MM AQ-3 would be applied to the actual projected Project-generated emissions after incorporation of the APMs and mitigation measures.

The three programs identified on page 4.3-49 of the Draft EIR do not affect GHGs generated by construction equipment. As discussed in the Draft EIR, the EPA's Natural Gas ENERGY STAR Program improves operational efficiency and reduces methane emissions from pipeline projects. Operational methane emissions were not calculated and were not included in the Impact AQ-3 emissions analysis. Therefore, reductions attributable to the Natural Gas STAR Program are not applicable. PG&E's ClimateSmart™ Program is similarly not applicable to Impact AQ-3 as presented in the Draft EIR. The ClimateSmart™ Program reduces offsets emissions generated by the end use of natural gas conveyed by PG&E. GHG emissions from end use consumption (burning) of natural gas to be conveyed by the proposed Project were not calculated and did not factor into the significance determination. The California Climate Action Registry (CCAR) enables members to measure, verify, and publicly report their GHG emissions. However, CCAR does not require that specific emission reductions be achieved or that specific emission reduction measures be implemented. Although CCAR provides a mechanism for verification and publication, participation would not result in GHG emission reductions associated with the proposed Project.

S-27 Comment acknowledged. Page 4.4-21, lines 17 through 18, of the Draft EIR have been revised. Refer to Section 4.0 of this <u>Revised </u>Final EIR for revisions to the Draft EIR.

S-28 Comment acknowledged. Page 4.4-27 and page 4.4-28 (Table 4.4-3) of the Draft EIR have been revised. Refer to Section 4.0 of this <u>Revised </u>Final EIR for revisions to the Draft EIR. <u>Page 4.4-13 of the Draft EIR discusses the existence of jurisdiction vernal pools and vernal swales within the project area, which are habitat for species including the vernal pool fairy shrimp (*Branchinecta lynchi*). Applicant proposed measures (APM BIO-21 through APM BIO-24) and mitigation measures MM BIO-1a and MM BIO-1b address impacts to vernal pool species.</u>

S-29 Comment acknowledged. Page 4.4-55, lines 5 through 8, of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-30 Comment acknowledged. Pages 4.4-84 through 4.4-87 (MM BIO-1c), of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-31 Comment acknowledged. Pages 4.4-89 through 4.4-91 (MM BIO-2a) of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-32 The commenter requests a revision of the vegetation clearing restriction period from 10 days to 30 days and that the restriction be limited to the wet period. The purpose of the 10-day restriction is to minimize impacts to sensitive habitats and features such as seasonal wetlands and riparian habitat, it also minimizes the spread of invasive species or soil pests throughout the construction window (refer to Section 4.4, Biological Resources, of the Draft EIR). Therefore, the 10-day requirement has been retained for construction activities in wetlands, riparian areas, and other sensitive habitats, but not for agricultural areas and other non-sensitive habitat features. Page 4.4-94, lines 10-12 (MM BIO-3), of the Draft EIR have been modified accordingly. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-33 Please refer to response to comment S-32.

S-34 Please refer to response to comment S-32.

S-35 Please refer to response to comment S-32.

S-36 This comment provides background information and orientation for comments S-37 through S-44. Please refer to individual responses to comments S-37 through S-44.

S-37 The commenter requests modification of language regarding fencing of wetland features. A portion of the requested text has been implemented. Page 4.4-81, lines 6-7, (MM BIO-1a) have been revised to indicate where jurisdictional wetlands should be fenced for maximum avoidance. Refer to Section 4.0 of this Revised Final EIR for revisions of the Draft EIR.

S-38 Comment acknowledged. Page 4.4-81, lines 10 through 11 (MM BIO-1a), of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-39 Comment acknowledged. Page 4.4-81, line 16 through page 4.4-82, line 5 (MM BIO-1a), page 4.4-85, lines 23 through 25 (MM BIO-1c), and page 4.4-94, lines 13 through 16 (MM BIO-3), of the Draft EIR have been revised to provide additional clarification about the conditions under which protective mats shall be used and/or the amount of topsoil that shall be salvaged. Suggested modifications to the vegetation clearing were revised based on the rationale provided above in response to comment S-32. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-40 Comment acknowledged. Page 4.4-82, lines 21-23, (MM BIO-1a), of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-41 Comment acknowledged. Pages 4.4-81 through 4.4-83, (MM BIO-1a), of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-42 Comment acknowledged. Pages 4.4-81 through 4.4-83, (MM BIO-1a), of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-43 Comment acknowledged. Page 4.4-83, lines 1 through 7 (MM BIO-1a), of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-44 Comment acknowledged. Page 4.4-83, lines 17 through 21 (MM BIO-1a), of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-45 The commenter requests a revision of the fencing practices discussed in MM BIO-1a and to clarify that plants used in restoration efforts be compatible with pre-construction conditions. Language regarding fencing practices was revised to require fencing of sensitive resources within the 100 foot ROW and a 50-foot wide buffer on either side of the ROW, or as determined in consultation with USACE, USFWS, or CDFG. Please refer to individual responses to comments S-46 through S-51.

S-46 Comment acknowledged. Page 4.4-85, lines 5 through 6 (MM BIO-1c), of the Draft EIR has been revised according to response to comment S-32. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-47 Comment acknowledged. Page 4.4-85, lines 11 through 13 (MM BIO-1c), of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR. Mitigation Measure BIO-1c outlines the measures for avoidance or, if riparian habitat cannot be avoided, restoration.

S-48 Comment acknowledged. Page 4.4-86, lines 31 through 32 (MM BIO-1c), of the Draft EIR has been revised to clarify when matching pre-construction conditions are appropriate. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-49 Please refer to response to comment S-45.

S-50 Comment acknowledged. The commenter requests that a portion of MM BIO-5 be removed. Instead, the text on page 4.4-120, lines 13 through 14, of the Draft EIR is revised to be consistent with page 4.4-120, lines 26 through 31, which states that any rare plant species within the study area (including the 100 foot-wide right-of-way and a 50 foot-wide buffer zone on each side of the right-of-way, work areas, staging areas, and/or launcher/receiver stations) will be flagged, accurately mapped on construction plans, and fenced to protect the area occupied by the species during construction, per APM BIO-3. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-51 Comment acknowledged. The commenter requests that a portion of MM BIO-5 be modified. This requested revision was not implemented because it would render MM BIO-5 inconsistent with fencing requirements stated elsewhere in Section 4.4, Biological Resources. However, page 4.4-120, lines 26 through 31, were revised to clarify fencing requirements. Refer to Section 4.0 of this Revised Final EIR for revision of the Draft EIR.

S-52 Subsequent to this comment being made, PG&E revised its Pipeline Crossing Summary Table to add the vernal feature that was not identified in the original summary table as a new line item. Accordingly, Table 2-5, starting on page 2-56 of the Draft EIR has been updated and is included in Section 4 of the Revised Final EIR. PG&E is currently working with the USFWS to determine the appropriate crossing method to minimize impacts to vernal pools. An HDD has been proposed to minimize impacts to the vernal feature inadvertently omitted from the original summary table, as well as the seasonal wetland complex surrounding this feature. However, until these details are worked out such that the crossing method to minimize impacts to vernal pools is identified and agreed to with the resource agencies, the text on page 4.4-79 of the Draft EIR will remain intact.

S-53 Comment acknowledged. Page 4.4-84 (MM BIO-1b) of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-54 Comment acknowledged. Page 4.4-93, lines 19 through 21 (MM BIO-3), of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-55 Comment acknowledged. Page 4.4-93, lines 33 through 35 (MM BIO-3), of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-56 Comment acknowledged. Page 4.4-94, lines 7 through 9 (MM BIO-3), of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-57 Comment acknowledged. The commenter requests that a portion of MM BIO-4a be modified. This requested revision was not implemented because it would render MM BIO-4a inconsistent with fencing requirements stated elsewhere in Section 4.4, Biological Resources. However, page 4.4-102, lines 1 through 7 were revised to clarify the buffers required for elderberry shrubs. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-58 Comment acknowledged. The commenter requests modifications to the portion of MM BIO-4a that addresses potential impacts to Swainson's hawk. However, CDFG also provided comments on the potential impacts to Swainson's hawk that conflict with this request. CDFG's recommendations regarding MM BIO-4a have been incorporated into the Draft EIR (refer to response to comment X-3). Therefore, only a portion of the text changes referencing the need to obtain a Section 2081 Incidental Take Permit have been implemented on page 4.4-104, lines 8 through 13 (MM BIO-4a). Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-59 Comment acknowledged. Page 4.4-105, lines 1 through 3 and page 4.4-105 (MM BIO-4b), lines 15 through 17 (MM BIO-4c) have been revised to remove the language limiting construction work to the period November through February due to the conflict with construction windows for work within giant garter snake habitat and the fact that mitigation for impacts to Swainson's hawk is addressed in MM BIO-4a. Implementing Alternative Option H if all suitable Swainson's hawk trees cannot be avoided within the conservation areas is acknowledged to potentially result in greater impacts to biological resources. Therefore, revisions have been made to page 4.4-105, lines 10 through 12 (MM BIO-4b) and page 4.4-105, lines 26 through 29 (MM BIO-4c). Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

S-60 Comment acknowledged. Page 4.4-120, lines 15 through 17 (MM BIO-5), of the Draft EIR have been revised. Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

S-61 Comment acknowledged. Although it is acceptable to use the phrase Area of Potential Effect (APE) in CEQA documents, instances where APE was used in the Draft EIR have been changed to "cultural study area" in order to reduce confusion with the Project study area. The specific places where changes have been made are as follows: Section 4.5, Cultural Resources, page 4.5-3, line 24; page 4.5-4, line 5; page 4.5-8, lines 20 through 21; page 4.5-21, line 31; page 4.5-22, lines 10, 13 through 14, and 17; page 4.5-23, line 33; page 4.5-24, line 16; page 4.5-25, line 15; page 4.5-28, line 24; page 4.5-35, line 31; page 4.5-36, line 5; and page 4.5-39, line 4. Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

S-62 Comment acknowledged. The word "Three" has been changed to "Several" on page 4.5-1, line 10 of the Draft EIR. Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

S-63 Comment acknowledged. Page 4.5-3, lines 21 through 29, of the Draft EIR has been revised to provide a more complete and accurate description of the pedestrian field survey process. Refer to Section 4.0 of this <u>Revised</u> Final EIR for revisions to the Draft EIR.

The commenter also requested that the following text be inserted: "If the existing documentation for previously recorded resources was adequate, or if the resources had been previously evaluated, the resource record was not updated." This sentence was not inserted because site records were updated for adequately documented and previously evaluated resources. For example, YOL-HRI-4/114 Herman Ricter House DPR Update form in Appendix D of Appendix F-5 of the Draft EIR.

S-64 Comment acknowledged. Page 4.5-11, line 16, through page 4.5-12, line 3, have been moved to page 4.5-1 of the Draft EIR, beginning under the subheading Methodology. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-65 Comment acknowledged. Page 4.5-36, lines 13 through 19 (APM CR-3), of the Draft EIR has been revised to provide more specific information regarding the geo-archaeological study and monitoring activities. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-66 Comment acknowledged. Please refer to responses to comments S-67 and S-68.

S-67 Comment acknowledged. Page 4.5-40, lines 20 through 21 of the Draft EIR have been updated to include the suggested sentence. Refer to Section 4.0 of this Revision Final EIR for revisions to the Draft EIR.

S-68 Comment acknowledged. Page 4.5-41, lines 25 through 26 of the Draft EIR have been updated to include the suggested sentence. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-69 Comment acknowledged. Page 4.5-43, lines 5 through 21 (MM CR-1), of the Draft EIR have been revised to clearly identify steps to be taken if any unknown resources are identified. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-70 Pages 4.5-43 through 4.5-46 of the Draft EIR state that the *potential* Cultural Resource impacts associated with Alternative Options A, B, D, E, and H would be greater than under the proposed Project because these alternative options occur in areas that have not been previously surveyed. As such, MM CR-1, in association with APM CR-1 through CR-5, would be required to be implemented for these alternative options to reduce impacts to less than significant levels.

Pages 4.5-45 through 4.5-48 have been revised and Table 4.5-2 updated to reflect that Alternative Options F, I, and J would have similar impacts on cultural resources as the proposed Project. Furthermore, similar text changes have been made on page ES-9, lines 13 through 16; page ES-11, lines 11 through 14; page ES-12, lines 11 through 13; and page ES-24, Table ES-2. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-71 The geotechnical report prepared for the proposed Project notes that the pipeline alignment crosses three documented faults: the Great Valley, Dunnigan Hills, and Willows faults. The three faults are thought to exist at depth and do not reach the surface where they cross the proposed alignment; however, the Great Valley and Dunnigan Hills faults are considered active. The geotechnical report for the proposed Project does not provide conclusive evidence that there are no fault movements or that the faults will not become active at or near the pipeline alignment. Therefore, a site specific seismic analysis is needed for the proposed pipeline alignment in the area of the documented faults. CSLC has considered PG&E's proposed changes to the language in Impact GEO-1 and MM GEO-1. A portion of Impact GEO-1 on Page 4.6-39 of the Draft EIR has been revised. MM GEO-1 on page 4.6-39 and 4.6-49 of the Draft EIR has also been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-72 Comment acknowledged. The word "then" has been changed to "than" on page 4.6-5, line 25 of the Draft EIR. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-73 Comment acknowledged. The word "curst" has been changed to "crust" and "case" to "cause" on page 4.6-19, lines 13 through 14 of the Draft EIR. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-74 Comment acknowledged. The word "total" has been changed to "tonal" on page 4.6-23, line 7 of the Draft EIR. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-75 The document entitled Review of EIR for PG&E Lines 406 and 407, prepared by Kiefner and Associates, dated June 12, 2009 (included as an appendix to Comment Set S) on behalf of PG&E has been reviewed. The responses are included in the responses to comments S-94 through S-97 below. A revised System Safety and Risk of Upset report is included as Appendix H-3 of this Revised Final EIR. ~~This review did not result in any changes to the quantitative risk assessment presented in the System Safety and Risk of Upset report, included in Appendix H of~~

~~the Draft EIR. As a result, no revisions to Table 4.7-5 of the Draft EIR are necessary.~~

The applicable federal pipeline regulations (49 CFR 192) use a population density approach to develop design, operations, and maintenance standards for natural gas pipelines. More rigorous requirements are imposed on pipelines in more densely populated areas than those in rural areas. However, these standards should not be confused with a qualitative or quantitative risk assessment. Such assessments, using the approach methodology presented in the Revised System Safety and Risk of Upset report, which was prepared by EDM Services, Inc. for the proposed Project, and is included as ~~a part of~~ Appendix H-3 of the ~~Draft~~ Revised Final EIR, are routinely used to evaluate and quantify the risks posed by linear pipeline projects. These risk assessments estimate the likelihood of a variety of consequences that may result from a given facility while the federal and state pipeline regulations provide standards for design, operation, and maintenance.

PG&E's comments that the approach does not adequately take into account the specific attributes of the proposed pipeline, especially those attributes that relate to the vintage of the facility (e.g., advances in construction materials and techniques such as external coatings, radiographic inspection of weld joints, improvements in cathodic protection system monitoring, integrity management plans, etc.).

As stated in the revised System Safety and Risk of Upset report, located in Appendix H-3 of ~~the Draft~~ this Revised Final EIR, newer pipelines do incur reportable incidents less frequently than pipelines constructed prior to about the 1940s. (See Table 4.1.2-2 of the System Safety and Risk of Upset report.) However, many of the causes of unintentional releases are to some extent time dependent. For example, an older line is more likely to experience a release caused by external corrosion, since it takes time for external corrosion to develop a through wall pit, resulting in a release. As stated in the Draft EIR, during the early years of operation, we would expect the rate of external corrosion caused incidents from the proposed pipe segment to approach zero. However, the baseline probability of reportable releases is intended to reflect the average rate over a 50-year project life. Using data from pipelines recently constructed, as the commenter suggests, would not accurately represent the average performance over the pipeline life. These data might be useful in predicting the frequency of releases from the proposed pipeline during its early years of operation, but they would not be representative of the proposed pipeline over its 50-year project life.

PG&E provided data for another pipeline project (Line 108) which indicated that for gas transmission pipelines constructed after 1990, the frequency of reportable releases is reduced by less than 30 percent. (These data have not been independently verified.) The Line 406/407 Draft EIR used a baseline frequency of USDOT reportable unintentional releases of 0.196 incidents per 1,000 mile-years, before mitigation. This value is roughly two-thirds (35 percent reduction) of the actual reportable incident rate from 2002 through 2008 for onshore gas transmission pipelines (0.30 incidents per 1,000 mile-years). The baseline incident rate used in the Line 406/407 Draft EIR reflects a reduction to account for the "modern" pipeline being proposed by PG&E. The methodology for making these adjustments is presented in ~~on pages 21 through 27 of~~ the revised System Safety and Risk of Upset report. This reduction (35 percent reduction) closely matches the data provided by PG&E for their Line 108 project (30 percent reduction). The baseline frequency was further reduced 50 percent to account for the proposed mitigation (e.g., modern line pipe, thicker pipe wall, use of marker tape in Class 3 areas, increased depth of cover, etc.). The mitigated frequency of unintentional releases used in the quantitative risk assessment was 0.098 incidents per 1,000 mile-years, which is roughly one-third the frequency of reported releases from onshore gas transmission pipelines from 2002 through 2008 (0.30 incidents per 1,000 mile-years).

The commenter suggests that the safety associated with the proposed modern pipeline segments should far exceed the national average fatality rate of 1×10^{-5} fatalities per mile-year. The risk assessment included risk measurement terminology that was not defined in earlier versions of the document, which has resulted in some confusion. A revised System Safety and Risk of Upset report was completed by EDM Services, Inc. (October 2009) for the proposed Project, and is included as Appendix H-3 of this Revised Final EIR. The EDM report findings are summarized in the Introduction to this section (Section 3.0) of the Revised Final EIR. Revisions to the Draft EIR, Section 4.7, Hazards and Hazardous Materials, and Section 4.9, Land Use and Planning, regarding the risk analysis are provided in Section 4.0 of this Revised Final EIR.

The risk analysis was revised because the aggregate risk was calculated and erroneously reported as individual risk. In addition, the risk analysis incorrectly compared the aggregate risk to the individual risk threshold of an annual likelihood of fatality of 1:1,000,000. The individual risk is defined as the frequency that an individual may be expected to sustain a given level of harm from the realization of specific hazards, at a specific location, within a specified time interval (measured as the probability of a fatality per year). Aggregate risk is the total anticipated frequency of fatalities that one might anticipate over a given time period for all of the project components (the entire pipeline system). There is no known established threshold for aggregate risk.

Section 4.1.4 of the Draft EIR correctly stated that a commonly accepted individual risk significance threshold is an annual likelihood of one in one-million (1:1,000,000) for fatality (used by the California Department of Education for school sites). The risk level is typically determined for the maximally exposed individual (assumes that a person is present continuously—24 hours per day, 365 days per year).

The highest risk along a segment of pipeline is to persons located immediately above the pipeline, and the risk decreases as a person is farther away from the pipeline. The maximum risk posed by Line 406 before mitigation is 1:2,137,000, and after mitigation it is 1:4,274,000 chance of fatality per year. The maximum risk posed by Line 407 before mitigation is 1:2,062,000, and after mitigation it is 1:4,115,000 chance of fatality per year. The maximum risk posed by Line DFM before mitigation is 1:4,255,000, and after mitigation it is 1:8,475,000. Because the calculated individual risk is less than the threshold of 1:1,000,000, the risk is considered to be less than significant.

~~And in fact, the analysis presented in the Draft EIR results in a fatality rate roughly one-seventh the national average suggested by the commenter, versus six times the national average as stated by the commenter.~~

~~In making the comparison, the commenter has made a mathematical error by not taking into account the length of the proposed pipeline segments when comparing the national fatality rate to the findings presented in the Draft EIR. Using the data presented above and the methodology suggested by the commenter, one might expect the frequency of fatalities to be reduced by roughly one-third, from the national average of $1.0\text{x}10^{-5}$ fatalities per mile-year (actual USDOT data from 1988 through 2008) to $0.67\text{x}10^{-5}$ fatalities per mile-year for the proposed Project. Using this value and multiplying by the proposed 42-miles of new pipeline, the qualitative annual likelihood of fatalities from the proposed Project would be $2.8\text{X}10^{-4}$ fatalities per year ($0.67\text{x}10^{-5}$ fatalities per mile-year x 42 miles = $2.81\text{X}10^{-4}$ fatalities per year). Using the commenter's qualitative approach correctly would yield a result almost five times higher that the result presented in the Draft EIR ($2.81\text{x}10^{-4}$ versus $6.08\text{x}10^{-5}$ fatalities per year).~~

~~The predicted frequency of fatalities presented in the Draft EIR is 1.45x10^{-6} fatalities per mile-year (6.08x10^{-5} fatalities per year/42 miles = 1.45x10^{-6} fatalities per mile-year). This frequency is roughly one-seventh the frequency of fatalities suggested by the commenter (1x10^{-5} fatalities per mile-year), which is the national average for the period from 1988 through 2008. However, based on the population density along the pipeline (the majority of the pipeline lies in very rural areas, with an extremely low population density), among other factors, the result presented in the Draft EIR is appropriate.~~

~~The frequency of fatalities on domestic onshore gas transmission pipelines was 3.4x10^{-6} fatalities per mile-year, for the period between from 2002 through 2008. The predicted frequency of fatalities from the proposed pipeline is less than one-half this value (3.4x10^{-6} versus 1.45x10^{-6} fatalities per mile-year).~~

The commenter suggests that the frequency of external corrosion-caused incidents used in the Draft EIR should be significantly reduced because PG&E will install remote monitoring equipment, capable of monitoring cathodic protection potentials at approximately one-mile intervals. While these devices offer real-time monitoring of the pipe to soil potential at the point of installation, they do not provide any data for points in between. As a result, they are not effective in providing early detection of pitting corrosion due to coating holidays, or interference from third party substructures, etc. The unmitigated external corrosion incident rate used in the Draft EIR was reduced by one-third to reflect the fact that the pipeline will be operated at ambient temperatures, have modern externally corrosion coating, and an impressed current cathodic protection system.

S-76 The Draft EIR text on pages 4.7-14 and 4.7-15 have been clarified to reflect the fact that PG&E has adopted method two for determining High Consequence Areas. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-77 Please refer to response to comment S-76.

S-78 Please refer to response to comment S-76.

S-79 The CSLC serves the people of California by providing stewardship of the lands, waterways, and resources entrusted to its care through economic development, protection, preservation, and restoration. The CSLC has broad mandates for protection of California's natural environment. The CSLC staff often prepare EIRs for projects that involve leases of State lands. For this Project, the CSLC is the lead agency for the CEQA environmental document. While PG&E is a CPUC-regulated public facility, other pipeline guidelines should be followed when those guidelines result in an increase in the public safety. The federal regulations (49 CFR 192) are minimum safety requirements for pipeline facilities and the transportation of gas. The required DOT regulations, along with PG&E Project features that meet and exceed the minimum requirements, would reduce risks of project upset. Even though the project risk impacts are less than significant, additional measures shall be implemented to further reduce risks of project upset. MM HAZ-2a and MM HAZ-2b have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

~~The risks posed by the proposed Project exceed generally acceptable significance thresholds (1:1,000,000 risk of serious injury or fatality). As a result, mitigation measures must be developed to either avoid the impact altogether, minimize the impact by limiting the degree or magnitude of the action and its implementation, rectify the impact, or reduce or eliminate the impact over time (CEQA Guidelines Section 15370).~~

S-80 The text has been changed on page 4.7-31 of the Draft EIR to reflect the clearing of vegetation to a 50-foot radius, unless this extends beyond the permanent right-of-way or temporary use area secured for construction. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-81 Please refer to response to comment S-80.

S-82 The suggested text change has been made to page 4.7-31 of the Draft EIR. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-83 The suggested text change has been made to page 4.7-36 of the Draft EIR. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-84 The commenter disagrees with the proposed requirement to perform a baseline smart pig inspection using a high resolution internal inspection tool within the first six months of pipeline operation, contending that the completed pipeline will be hydrostatically tested following construction.

The proposed pipeline would be in close proximity to planned developments, including school facilities. ~~The risks posed by the proposed Project exceed generally acceptable significance thresholds (1:1,000,000 risk of serious injury or~~

~~fatality). As a result, mitigation measures must be developed to either avoid the impact altogether, minimize the impact by limiting the degree or magnitude of the action and its implementation, rectify the impact, or reduce or eliminate the impact over time (CEQA Guidelines Section 15370).~~ The proposed mitigation requiring a baseline internal inspection is directed at minimizing the likelihood of an unintentional release, thereby reducing the risk to the public.~~, which has been identified as a significant risk.~~

The post-construction hydrostatic test proposed by PG&E is required by 49 CFR 192.505. As a result, it is not considered mitigation.

The baseline or “fingerprint” internal inspection is intended to reduce the likelihood of an unintentional release by providing verification of construction quality and collecting inspection data for future reference, which can be compared to subsequent internal inspection results. These comparisons allow the operator to determine corrosion rates and evaluate “hot spots.” The value of conducting these inspections has been demonstrated. For example, a recently constructed 25-mile, 42-inch diameter gas pipeline was inspected six months after being commissioned; over 40,000 metal loss features were identified. In this case, the vast majority of the defects were internal, which are not anticipated for the proposed Project. But over 800 external metal loss defects were also identified.

The commenter suggests that performing an in-line inspection may not be the best technology for assessing potential threats and therefore may be in violation of 49 CFR 192.921. The proposed mitigation does not preclude PG&E from using other technologies to comply with 49 CFR 192 Subpart O. The internal inspections required in the mitigation measure are intended to be *in addition* to the regulatory requirements; otherwise, these measures would not be considered mitigation. PG&E will likely be required to employ additional technologies to comply with the federal regulation.

The commenter discusses limited resources for inspections and that mandating ILI on these new segments will detract from being able to inspect other lines. This comment is noted. The proposed mitigation requiring a baseline internal inspection is directed at minimizing the likelihood of an unintentional release, thereby minimizing ~~reducing~~ the risk to the public.

S-85 Please refer to response to comment S-84.

S-86 The CSLC has considered PG&E's proposed changes to the language in MM HAZ-2b, and the reasons for the need for PG&E to be able to remotely operate the valves. The text of MM HAZ-2b, on page 4.7-38 of the Draft EIR, has been revised to incorporate ~~both the features of the remotely controlled valves and~~ the benefits of automatically controlled valves during potentially critical events (e.g., line ruptures). Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-87 Comment acknowledged. Page 4.8-18, line 17, (MM HWQ-1) of the Draft EIR has been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-88 Comment acknowledged. Page 4.8-18, lines 25 through 26, (MM HWQ-1) of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-89 Comment acknowledged. Page 4.8-20, lines 18 through 31, (MM HWQ-2) of the Draft EIR have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-90 Comment acknowledged. Page 4.8-21, line 23 to page 4.8-22, line 22 (MM HWQ-3); page 4.8-34, lines 30 through 24; and, page 4.1-13, lines 15 through 18; of the Draft EIR have been modified. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

S-91 Please refer to response to comment S-90.

S-92 Please refer to response to comment S-90.

S-93 Please refer to response to comment S-90.

Response to Comment Set S's Attachment

S-94 The commenter states, "Although these variances in raw data or interpretation imply that some numerical results might change, these would not necessarily alter the overall conclusions or invalidate the assessment." This comment is noted and agreed.

S-95 This comment pertains to numerous portions of the System Safety and Risk of Upset report, which was prepared by EDM Services, Inc. for the proposed Project.~~, and is included as a part of Appendix H of the Draft EIR.~~ Revisions have been made to the System Safety and Risk Upset report, and it is included as Appendix H-3 of this Revised Final EIR. ~~are included in Section 4.0 of this Final EIR.~~

Section 2.1.1, bottom of page 2 The recommended additional wording has been added.

Section 4.1.1, page 11 The commenter notes that different sources provide different values and definitions for mortality after exposure to fires. The commenter notes that a radiant heat flux of 5,000 btu/ft^2-hr is cited by one source as resulting in a 1 percent mortality after 30 seconds of unabated exposure. In fact, in many cases, an able-bodied person would take actions to increase the separation distance or seek cover during that 30 second period. The Draft EIR is correct; the reference cited (CDE 2007) uses a 1 percent mortality for this radiant heat flux level. The System Safety and Risk Upset report text has been revised to reflect the variance in different data sources. Refer to page 22 of ~~the~~ Section 4.1.1 of the System Safety and Risk of Upset Report included in this Revised Final EIR as Appendix H-3 for revisions to the report ~~Draft EIR~~.

~~However, only the 8,000 btu/ft^2-hr radiant heat flux isopleth was used in the quantitative risk assessment which begins on page 30 of the report. As a result, any conservatism that may have been implied by these differences of professional opinion in the text on page 11 of the report was not reflected in the analysis. In fact, any potential impacts beyond the 8,000 btu/ft^2-hr isopleth were excluded from consideration, since able bodied persons would normally be expected to escape the exposure before the impact would be serious.~~

Section 4.1.2, pages 13-14 The commenter suggests that presenting gas pipeline release data for the period between 1970 through June 1984 is not relevant. Table ~~4.1.2-1~~ 4.2.5-1 of the System Safety and Risk of Upset report summarizes the various release data sets. As indicated in this table, the frequency of reportable incidents for gas lines from 1970 through June 1984 is essentially the same as that for hazardous liquid lines, during the period when the reporting criteria was the same ($5,000). This demonstrates the similar incident rates between gas and hazardous liquid pipelines subject to the USDOT's jurisdiction. The data also helps illustrate the reduction in the frequency of injuries and fatalities over the past four decades. It should be noted that these baseline data were not used in the quantitative analysis~~, which begins on page 30 of the System Safety and Risk of Upset report~~.

Section 4.1.2, pages 14-15 The commenter questions the USDOT frequency of release data provided for July 1984 through 2007. However, the commenter is not making an "apples to apples" comparison. The commenter has tallied the "significant" incidents, as compiled by the USDOT. The Draft EIR presents the "reported" incidents, as reported to the USDOT. The USDOT filters the reported incidents and provides reports for "significant" pipeline incidents. These incidents include those which result in:

- fatality or injury requiring in-patient hospitalization;
- $50,000 or more in total costs (measured in 1984 dollars);
- highly volatile liquid releases of 5 barrels or more or other liquid releases of 50 barrels or more; or
- liquid releases resulting in an unintentional fire or explosion.

Section 4.2~~1~~.2, pages ~~14~~ 25 through 26 ~~15~~ of the System Safety and Risk of Upset report, included in Appendix H-3 of the Revised Final ~~Draft~~ EIR, have been revised to reflect this information.~~ Refer to Section 4.0 of this Final EIR for revisions to Appendix H of the Draft EIR.~~

One of the primary differences is that the "reported" incidents include incidents that were considered significant in the judgment of the operator, even though they did not meet the other USDOT reporting criteria. As a result, there are a higher number of "reported" incidents than there are "significant" incidents. This difference is noteworthy. For the eight year period from 2002 through 2008, there were 368 "significant" incidents and 614 "reported" incidents from onshore gas transmission pipelines.

Section 4.2~~1~~.2, pages 25 ~~14~~ through 26 ~~15~~ of the System Safety and Risk of Upset report, which was prepared by EDM Services, Inc. for the proposed Project, is included as a part of Appendix H-3 of the ~~Draft~~ Revised Final EIR and has been revised to clarify this difference. ~~(pages 14 and 15).~~ The text has also been revised to correct an error on page 26 ~~15~~ of the report, where some gathering line incidents were included in the data set. ~~No changes to the Draft EIR were necessary.~~

The commenter notes that there were 323 “significant” incidents on onshore gas transmission lines between 1988 through 2008. This figure is in error. Data pulled from the USDOT Pipeline and Hazardous Materials Safety Administration (PHSMA) web site on July 3, 2009 indicates that there were 846 “significant” incidents on onshore gas transmission pipelines during this eleven year period and an additional 262 on offshore gas transmission line segments, for a total of 1,108. Some of the incident rates cited by the commenter are also in error due to the incorrect number of incidents used in the calculations. The table of “significant” incidents from onshore transmission pipelines, pulled directly from the PHSMA web site on July 3, 2009 is presented below. Similar tables are available for offshore and gathering lines.

National Gas Transmission Onshore:
Significant Incidents Summary Statistics: 1988-2008

Year	Number	Fatalities	Injuries	Property Damage ($)
1988	31	2	9	6,707,494
1989	29	4	15	16,303,907
1990	36	0	15	12,752,888
1991	27	0	11	14,456,387
1992	32	3	14	13,078,380
1993	43	1	16	21,762,671
1994	34	0	15	53,262,153
1995	22	0	7	8,269,519
1996	34	1	5	12,589,358
1997	26	1	5	11,068,642
1998	40	1	11	40,150,999
1999	34	2	8	19,370,527
2000	45	15	16	16,897,783
2001	45	2	5	12,977,700
2002	40	1	4	21,306,317
2003	61	1	8	52,523,788
2004	43	0	2	10,045,994

Year	Number	Fatalities	Injuries	Property Damage ($)
2005	64	0	5	134,090,086
2006	60	3	4	29,028,775
2007	55	2	7	40,022,492
2008	45	0	5	105,159,045
Total	846	39	187	651,824,913
Source: http://primis.phmsa.dot.gov/comm/reports/safety/SigPSI.html				

The PHMSA onshore transmission pipeline incident report above was independently reconciled to within less than 4 percent of the data included in the PHMSA transmission pipeline raw incident database. The raw transmission line incident database was downloaded from the PHMSA web site on July 3, 2009. All incidents which occurred outside the period of January 1, 2002 and December 31, 2008 were deleted. All incidents which were indicated to have occurred on an "offshore" or "gathering" line segment were also deleted. The remaining data was filtered to only include those incidents which resulted in $50,000 or greater in property value, an injury, or a fatality. This resulted in 535 incidents for the 2002 through 2008 period, slightly more than the 516 incidents reported by PHMSA for the same period in the above table. The difference is that the PHMSA report reflects adjustments in the property damage to convert the result to 1984 constant dollars; this results in somewhat fewer incidents being included in their report than the reconciliation, which did not include an adjustment for inflation.

Section 4.1.2, page 16 Figure 4.2~~1~~.2-1 and related text on pages 27 and 28 ~~16~~ of the System Safety and Risk of Upset report, included as Appendix H-3 of this Revised Final EIR, have been modified to include "significant" incidents. ~~No revisions to the Draft EIR are necessary. Refer to Section 4.0 of this Final EIR for revisions to Appendix H of the Draft EIR.~~

Section 4.1.2, page 17 A value for "significant" incidents has been added to the bullet list on page 28 ~~17~~ of the System Safety and Risk of Upset report, included as Appendix H-3 of this Revised Final EIR. The value is the same as that proposed by the commenter. ~~No revisions to the Draft EIR were necessary. Refer to Section 4.0 of this Final EIR for revisions to Appendix H of the Draft EIR.~~

Section 4.1.2, page 18 Figure 4.2~~1~~.2-2 on page 29 ~~18~~ of the System Safety and Risk of Upset report, included in Appendix H-3 of this Revised Final ~~the Draft~~ EIR has been updated.~~ Refer to Section 4.0 of this Final EIR for revisions to Appendix H of the Draft EIR.~~

Section 4.1.2, page 20 Table 4.2.5-1 ~~4.1.2-1~~ on page 31 ~~20~~ of the System Safety and Risk of Upset report, included in Appendix H-3 of this Revised Final ~~the Draft~~ EIR has been updated.~~ Refer to Section 4.0 of this Final EIR for revisions to Appendix H of the Draft EIR.~~

Section 4.1.2, pages 18 through 20 [This information is now pages 29 through 31 of the System Safety and Risk of Upset Report included as Appendix H-3 of this Revised Final EIR]. The commenter suggests that the U.S. hazardous liquid pipeline leak history may not be relevant. However, for the period cited, the reporting threshold was the same as the gas transmission pipelines for the 1970 through June 1984 period ($5,000). During these periods, where the reporting threshold was the same, the frequency of incidents was essentially identical. These data provide a useful benchmark for predicting incident frequencies of a similar size. The major failure modes are similar for both modern gas and hazardous liquid pipelines subject to USDOT jurisdiction (e.g., third party damage, external corrosion, and other causes).

The California hazardous liquid pipeline data is also useful. These data, which were presented in the California Hazardous Liquid Pipeline Risk Assessment (Payne, Brian L. et al., EDM Services, Inc. 1993. California Hazardous Liquid Pipeline Risk Assessment, Prepared for California State Fire Marshal, March.) facilitated the assessment of impacts caused by a variety of parameters (e.g., operating temperature, pipe age, operating pressure, operating stress level, etc.). These data were used to help develop the baseline frequency of unintentional releases used in the Draft EIR.

Section 4.1.2, page 21 The commenter notes that many of the factors in the bulleted list can be attributed to features associated with older pipelines and construction methods and that the baseline release frequency should be adjusted accordingly. As noted on pages 28 through 33 ~~23 and 27~~ of the System Safety and Risk of Upset report, the baseline incident rate for third party damage was reduced by 30 percent, the external corrosion incident rate was reduced by one-third, and the incident rate for all other causes was reduced by one-third. The resulting baseline incident rate used in the Draft EIR before mitigation was 0.196 incidents per 1,000 mile-years (reference page 28 ~~27~~ of the System Safety and Risk of Upset report). This result is less than 9 percent higher than the commenter proposed baseline incident rate of 0.18 incidents per 1,000 mile-years. ~~(See comment regarding page 31 of the System Safety and Risk of Upset report.)~~ This difference does not have a meaningful impact on the study results. Further, ~~past~~ post mitigation, the baseline incident rate was reduced by 50 percent to 0.098 incidents per 1,000 mile-years; this value is roughly one-half the value proposed by the commenter.

Section 4.1.2, page 23 The commenter suggests that additional reductions should be made to address issues such as the resistance of the pipe to immediate penetration from equipment due to the proposed pipe wall thickness. The Draft EIR did consider the effect of additional wall thickness. The System Safety and Risk of Upset included an adjustment to the baseline incident rate, assuming that the mitigation measure would require the 30-inch diameter lines to have a minimum pipe wall thickness of 0.375-inches. The effect of this mitigation is discussed on page 88 ~~57~~ of the revised System Safety and Risk of Upset report included as Appendix H-3 of this Revised Final EIR. As noted, the increased pipe wall thickness, increased depth of cover, and supplemental third party protection was assumed to reduce the frequency of third party caused incidents by one-third. At the time the Draft EIR was prepared, PG&E's engineering of the pipeline was not complete. As a result, the proposed pipe wall thickness was subject to change. Therefore, the benefits provided by the increased pipe wall thickness were considered post mitigation.

~~It should be noted that the baseline incident rate used in the Draft EIR before mitigation was 0.196 incidents per 1,000 mile years (reference page 27 of the System Safety and Risk of Upset report). This result is less than 9 percent higher than the commenter proposed baseline incident rate of 0.18 incidents per 1,000 mile-years, which is intended to reflect reductions for additional pipe wall thickness, depth of cover, etc. Post mitigation, the Draft EIR assumed that the baseline frequency of unintentional releases would be reduced by approximately 50 percent (reference page 4.7-39 of the Draft EIR) to 0.098 incidents per 1,000 mile-years; this value is slightly more than one-half (54 percent) the value proposed by the commenter.~~

Section 4.2.1 Page 27 The commenter notes that PG&E will be installing remote monitoring of cathodic protection potential at approximately one mile intervals and indicates that this will reduce the likelihood of external corrosion caused incidents. While these devices offer real time monitoring of the pipe to soil potential at the point of installation, they do not provide any data for points in between. As a result, they are not effective in preventing early detection of pitting corrosion due to coating holidays, or localized interference from third party substructures, etc. The external corrosion incident rate used in the Draft EIR was reduced by one-third to reflect the fact that the pipeline will be operated at ambient temperatures, have modern externally coated pipe, and an impressed current cathodic protection system (reference page ~~27~~ 28 of the revised System Safety and Risk of Upset report). The resulting baseline incident rate used in the Draft EIR before mitigation was 0.196 incidents per 1.000 mile-years (reference page ~~27~~ 28 of the System Safety and Risk of Upset report). This result is less than 9 percent higher than the commenter proposed baseline incident rate of 0.18 incidents per 1,000 mile-years.

Section 4.1.3, page 29 and 30 Table 4.4.2-1 ~~4.1.3-2~~ does not contain any data for LPG lines. The text on page 40 ~~30~~ of the System Safety and Risk of Upset report, included in Appendix H-3 of this Revised Final ~~the Draft~~ EIR, has been revised to avoid confusion, as requested by the commenter. No revisions to the Draft EIR were necessary. ~~Refer to Section 4.0 of this Final EIR for revisions to Appendix H of the Draft EIR.~~

Section 4.1.3, page 30 The commenter states that the probability of a worst-case scenario is greater in a rural location due to the higher operating stress levels and typically thinner wall pipe used in rural areas. The commenter notes that Class 3 lines comprise 11 percent of the total gas pipeline mileage and 14 percent of the gas pipeline reportable incidents, but that there has only been one fatality caused by a pipeline located in a Class 3 area since 1989. Since 2002, there have been no fatalities resulting from pipelines located in Class 3 or 4 areas. The commenter further states that the heavier pipe wall thickness and lower operating stress affects the susceptibility to failure and can affect its mode.

While the Class 3 line mileage percentage cited by the commenter has not been independently verified, the data indicates that the incident rate for pipelines located in Class 3 areas was 27 percent higher than one would predict using the same incident rate for all area Classes. The Draft EIR uses the same baseline incident rate for unintentional releases for all area Classes.

The data set cited by the commenter for fatalities in Class 3 and 4 areas is very small; the data set is too small to be statistically relevant for evaluating differences in the frequency of fatalities in different area Classes. For example, there were only 7 fatalities from gas transmission pipelines for the seven year period from 2002 through 2008. For the fourteen-year period from 1988 through 2008, 6 of the 39 fatalities (15 percent) have resulted from unintentional releases from onshore gas transmission pipelines in Class 3 and 4 areas. Using the line mileages provided by the commenter, 11.7 percent of the gas gathering and transmission line pipe was in Class 3 and 4 areas (11.4 percent in Class 3 and 0.3 percent in Class 4 areas). In other words, 15 percent of the fatalities resulted from releases on 11.7 percent of the pipe; this indicates that the fatality rate in Class 3 and 4 areas was about 28 percent higher than one would predict using the same fatality rate for all area Classes. It should be noted that the actual difference may vary somewhat, since the distribution of pipe in various area Classes includes some onshore gas gathering lines, in addition to the gas transmission pipelines; the fatalities only include those which occurred on onshore gas transmission lines. However, since this data set is so small, a single catastrophic incident could drastically skew the result and any conclusions that might be drawn.

In the absence of sufficient data to fully support a more rigorous analysis which differentiates the frequency of incidents in different area Classes, the Draft EIR used a common baseline frequency of unintentional release for all area Classes. This baseline release frequency was then used in the quantitative risk assessment which considered all of the possible release scenarios and their potential impacts on the various populations along the pipeline. The highest quantified individual risk along a segment of pipeline is to persons located immediately above the pipeline, and the risk decreases as a person is farther away from the pipeline. The maximum risk posed by Line 406 before mitigation is 1:2,137,000, and after mitigation it is 1:4,274,000 chance of fatality per year. The maximum risk posed by Line 407 before mitigation is 1:2,062,000, and after mitigation it is 1:4,115,000 chance of fatality per year. The maximum risk posed by Line DFM before mitigation is 1:4,255,000, and after mitigation it is 1:8,475,000. ~~This resulted in an~~

~~unmitigated risk of serious injury or fatality of 6.08x10^{-5} per year (annual likelihood of 1:16,000). This result was roughly one-third the value of 1.7x10^{-4} (annual likelihood of 1:6,000) which was obtained in the qualitative risk assessment using a frequency of 0.004 fatalities per 1,000 mile-years. (Reference page 29 of the System Safety and Risk of Upset report.)~~ It should be noted that ~~this~~ the qualitative approach is often used to evaluate pipeline risk in lieu of a quantitative approach, since the quantitative approach used in the Draft EIR, as revised in the Revised Final EIR, is much more rigorous and resource intensive.

Section 4.1.4, page 31 The commenter states that a baseline incident rate of 0.18 incidents per 1,000 mile-years could have been used instead of the baseline incident rate of 0.196 incidents per 1,000 mile-years which was used in the quantitative risk assessment presented in the System Safety and Risk of Upset report. This difference is less than 9 percent and would not have a meaningful impact on the study results. It should also be noted that the baseline rate of 0.196 incidents per 1,000 mile-years is before mitigation; as noted on page 4.7-39 of the Draft EIR, the proposed mitigation reduces the risk by 50 percent to 0.098 incidents per 1,000 mile-years.

Section 4.1.4, page 43 The migration of gas from a pipeline leak or rupture into a residence or building, although rare, has occurred. When the conditional probabilities used in the System Safety and Risk of Upset report are combined, the predicted probability of an indoor explosion resulting from a 1-inch diameter release from the proposed pipeline is less than 0.1 percent. In other words, this scenario results from less than one in one thousand releases.

Section 4.1.4, page 49 From 1988 through 2008, 6 of the 39 fatalities (15 percent) that have resulted from unintentional releases from onshore gas transmission pipelines have occurred in Class 3 and 4 areas. Since this data set is so small, a single catastrophic incident could drastically skew the result and any conclusions that might be drawn.

In the absence of sufficient data to fully support a more rigorous analysis which differentiates the frequency of incidents in different area Classes, the Draft EIR used a common baseline frequency of unintentional release for all area Classes. This baseline release frequency was then used in the quantitative risk assessment which considered all of the possible release scenarios and their potential impacts on the various population densities along the pipeline. The highest quantified individual risk along a segment of pipeline is to persons located immediately above the pipeline, and the risk decreases as a person is farther away from the pipeline. The maximum risk posed by Line 406 before mitigation is 1:2,137,000, and after mitigation it is 1:4,274,000 chance of fatality per year. The maximum risk posed by Line 407 before mitigation is 1:2,062,000, and after mitigation it is 1:4,115,000 chance of fatality per year. The maximum risk posed by Line DFM before mitigation is 1:4,255,000, and after mitigation it is 1:8,475,000. ~~This resulted in an unmitigated risk of serious injury or fatality of 6.08x10^{-5} per year (annual likelihood of 1:16,000). This result was roughly one-third the value of 1.7x10^{-4} fatalities per year (annual likelihood of 1:6,000) which was obtained in the qualitative risk assessment, which used a frequency of 0.004 fatalities per 1,000 mile-years. (Reference page 29 of the System Safety and Risk of Upset report.)~~ It should be noted that the ~~this~~ qualitative approach is often used to evaluate pipeline risk in lieu of a quantitative approach. However, the quantitative approach used in the Draft EIR, as revised in this Revised Final EIR, is much more rigorous and resource intensive.

Section 4.1.4, page 52 ~~From 1988 through 2008, 6 of the 39 fatalities (15 percent) that have resulted from unintentional releases from onshore gas transmission pipelines have occurred in Class 3 and 4 areas. Since this data set is so small, a single catastrophic incident could drastically skew the result and any conclusions that might be drawn.~~

~~In the absence of sufficient data to fully support a more rigorous analysis which differentiates the frequency of incidents in different area Classes, the Draft EIR used a common baseline frequency of unintentional release for all area Classes. This baseline release frequency was then used in the quantitative risk assessment which considered all of the possible release scenarios and their potential impacts on the various population densities along the pipeline. This resulted in an unmitigated risk of serious injury or fatality of 6.08x10^{-5} per year (annual likelihood of 1:16,000). This result was roughly one-third the value of 1.7x10^{-4} fatalities per year (annual likelihood of 1:6,000) which was obtained in the qualitative risk assessment, which used a frequency of 0.004 fatalities per 1,000 mile-years. (Reference page 29 of the System Safety and Risk of Upset report.) This The qualitative approach is often used to evaluate pipeline risk in lieu of a quantitative approach, since~~

~~the quantitative approach used in the Draft EIR, is much more rigorous and resource intensive.~~

The text of the System Safety and Risk of Upset is correct. If the population density increases, the likelihood of serious injuries and fatalities will increase accordingly, should the population be exposed to a fire or explosion resulting from an unintentional release. The data provided by the commenter indicates that the incident rate for pipelines located in Class 3 areas was 27 percent higher than one would predict using the same incident rate for all area Classes. ~~(See response to page 30 comment above.)~~ It should be noted that the Class 3 line mileage percentage cited by the commenter has not been independently verified.

Section 4.1.4, page 55 Appendix B of 49 CFR 192 allows the use of pipe manufactured to a variety of specifications. There is no requirement for pipe to comply with a specific edition of any of these specifications. The regulation also allows pipe of unknown or unlisted specifications to be used. And finally, pipe manufactured before November 12, 1970 may be used subject to certain restrictions. Because of the benefits of using modern pipe, the use of pipe manufactured in the year 2000 or later was included in the proposed Project mitigation. (Please refer to page 86 ~~56~~ of the revised System Safety and Risk of Upset report, included as Appendix H-3 to ~~the Draft~~ this Revised Final EIR.)

Section 4.1.4, page 57 Comment acknowledged.

S-96 The benefits of a modern pipeline have been incorporated into the baseline incident rate. The baseline frequency of unintentional releases used in the Draft EIR is 0.196 incidents per 1,000 mile-years. This frequency was reduced 50 percent to 0.098 incidents per 1,000 mile-years, post mitigation. For reference, the frequency of reported incidents from onshore gas transmission pipelines from 2002 through 2008 was 0.30 incidents per 1,000 mile-years, essentially three times the rate used for the proposed Project after mitigation. For reference, the frequency of "significant" incidents from onshore gas transmission pipelines from 2002 through 2008 was 0.18 incidents per 1,000 mile-years.

S-97 The data set cited by the commenter for fatalities in Class 3 and 4 areas is very small; the data set is too small to be statistically relevant for evaluating differences in the frequency of fatalities in different area Classes. For example, there were only 7 fatalities from onshore gas transmission pipelines for the seven year period from 2002 through 2008. For the 14 year period from 1988 through 2001, there were 3 fatalities in Class 3 areas and 3 fatalities in Class 4 areas. During this fourteen-year period, 6 of the 32 fatalities (19 percent) resulting from unintentional releases from onshore gas transmission pipelines occurred in Class 3 and 4 areas. If these two data sets are combined, from 1988 through 2008, 6 out of 39 fatalities (15 percent) resulted from unintentional releases from onshore gas transmission pipelines occurred in Class 3 and 4 areas. Since this data set is so small, a single catastrophic incident could drastically skew the result and any conclusions that might be drawn.

However, using the gas transmission and gathering pipeline mileage data compiled by the commenter (11.4 percent Class 3 and 0.3 percent Class 4), which has not been independently verified, it is clear that the frequency of fatalities in Class 3 and 4 areas is higher than in Class 1 and 2 areas. Specifically, from 1988 through 2008, 15 percent of the fatalities occurred in Class 1 ~~3~~ and 2 ~~4~~ areas while only 11.7 percent (11.4 + 0.3 percent = 11.7 percent) of the pipeline mileage was in Class 3 and 4 areas. It should be noted that the actual difference may vary somewhat, since the distribution of pipe data in various area Classes includes some onshore gas gathering lines, in addition to the onshore gas transmission pipelines; the fatalities only include those which occurred on onshore gas transmission lines.

COUNTY OF PLACER
Community Development Resource Agency

ENGINEERING & SURVEYING

MEMORANDUM

TO: MAYWAN KRACH, ECS DATE: JUNE 11, 2009

FROM: PHILLIP A. FRANTZ, ESD ~ ENGINEERING & SURVEYING DEPARTMENT

SUBJECT: PG&E LINE 406/407 NATURAL GAS PIPELINE ~ DEIR

Thank you for the opportunity to review the above-mentioned project for concerns relating to Placer County. After reviewing the submitted information, the Community Development Resource Agency ~ Engineering & Surveying Department and the Department of Public Works offer the following comments for your consideration regarding the proposed project:

1. Pages 3-65 through 3-67, Table 3-3, Cumulative Impact Analysis Projects: Most of the Placer County identified projects have construction completion dates of 2008 and 2009. These dates are not accurate as these improvements are not close to being constructed. Please revise accordingly. T-1
2. The proposed pipeline alignment must be coordinated to accommodate the ultimate 6 lane configuration for Baseline Road. The improvements at major intersections, such as Watt Ave., Brewer Road or Locust Road have not been designed yet, but may be up to 11 lanes wide, with sidewalks and landscaping areas adjacent to the roadway. T-2
3. Will street light or sign post foundations be precluded from the 50 ft easement? T-3
4. There was a previous proposal for a bridge type pedestrian overcrossing of Baseline Road, connecting Placer Vineyards to Sierra Vista, would the necessary foundations be permitted within the 50 ft easement? T-4
5. The final location of the Baseline/Brewer Main Line Valve should be coordinated with the Placer Vineyards development since it appears the valves are proposed to be located across the road from the high school. T-5
6. Page 4.13-20, paragraph 3: Brewer Road should be added to the list of impacted roadways. T-6
7. Advisory Comment: While the intersection is not within Placer County, the DEIR does not address how the proposed gas line alignment would accommodate the proposed reconfiguration of the Natomas Road intersection and UPRR track crossing along Riego Road. Both Placer and Sutter County have been notified by the PUC and UPRR that construction of an overcrossing of the railroad tracks will be required when the Riego Road/ Baseline Road is ultimately widened to 6 lanes. T-7

cc: Andrew Gaber, DPW ~ Transportation Division

Ref: state of ca pge line 406-407 natural gas pipeline.doc

RESPONSE TO COMMENT SET T

T-1 Comment acknowledged. Placer County was contacted and asked to provide appropriate dates for their cumulative projects listed in Table 3-3 of Section 3.0, Alternatives and Cumulative Projects. Placer County indicated that updating construction dates for the PVSP is difficult due to current litigation. Accordingly, Draft EIR pages 3-65 through 3-67, Table 3-3, have been updated to correctly identify that construction dates for projects within Placer County are unknown. Additionally, related changes have been made to page 4.12-33, line 5 of the Draft EIR. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

T-2 Please refer to response to comment K-2. This section of Line 407 is planned for construction in 2012. PG&E indicated they have met the civil engineering firm of McKay and Somps representing the developers of SVSP, PVSP, and Sutter Pointe Specific Plan, on several occasions in their Roseville and Sacramento offices in order to coordinate the pipeline vertical and horizontal alignment with the future road alignments dictated by the City of Roseville. PG&E has used the best design information available in locating the pipeline. Currently the road improvement plans are limited to line work in plan view only. The Baseline Road design has not progressed to include future elevations, drainages, or utility infrastructure. In the absence of final road improvement design drawings, PG&E has increased cover at major road crossing to 8 feet. In PG&E's experience, 8 feet of cover will generally allow for typical road construction and utility crossings. PG&E would like to work with Placer County to coordinate design of roads and adjacent areas so that potential conflicts can be addressed prior to the construction of the pipeline.

A mitigation measure (MM LU-1d) has been added to section 4.9, Land Use and Planning, to address potential conflicts with utilities. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

T-3 Streetlight and sign-post foundations will be allowed within the 50-foot permanent easement as long as proper clearance from the pipeline is maintained at 10 feet, and proper notification to PG&E is made prior to construction for concurrence.

T-4 A bridge-type pedestrian overcrossing of Baseline Road would most likely be allowed, but a review of the foundation design and proximity to the pipeline by PG&E would be required.

T-5 The eastern side of the valve lot is approximately 275 feet west of Brewer Road and approximately 400 feet west of the 1500-foot school ~~buffer~~ study zone, rather than across the road from the high school. Please refer to response to comment G-14 for further discussion on the Baseline/Brewer Main Line Valve Station placement.

T-6 Comment acknowledged. Brewer Road has been added to the list of impacted roadways on page 4.13-20 of the Draft EIR. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

T-7 PG&E indicated they have coordinated with the developers and included the future Riego Road design in the pipeline drawings to ensure that the pipeline will not be in conflict with the six lane expansion. Although PG&E does not have the detailed Riego Road design through the Natomas Road Intersection and Union Pacific Rail Road (UPRR) track crossing, the pipeline permanent easement is set back as if there are six lanes traveling through this area. PG&E is maintaining the setback distance from the current design of the six lanes traveling from the east and west along Baseline Road. Currently, PG&E's design location for its permanent 50-foot easement has the southern boundary located 70 feet north of the existing Riego Road centerline, tapering to 60 feet north of centerline as the pipeline progresses eastward due to a slight offset in Riego Road. In addition to the setback, PG&E has designed a HDD crossing under the UPRR, Natomas Drain, and Natomas Road. The HDD entry location is 275 feet east of the UPRR tracks and will exit approximately 400 feet west of Natomas Road. The pipeline will be at an approximate depth of 50 feet below the ground surface between the entry and exit locations.

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June 12, 2009

Via fax: (916) 574-1885
(original to follow by U.S. Mail)

Crystal Spurr
Project Manager
California State Lands Commission
100 Howe Avenue, Suite 100-South
Sacramento, CA 95825

Re: PG&E Line 406-407 Natural Gas Pipeline
SCH No. 2007062091
Comments on CA State Lands Commission Draft EIR No. 740

Dear Ms. Spurr:

We are writing on behalf of the Measure M Group, the proponents of the Sutter Pointe Specific Plan (SPSP) in Sutter County, currently under consideration for approval by the Sutter County Planning Commission and Board of Supervisors. The Measure M Group generally supports the extension of new natural gas pipelines as outlined in the DEIR, as the lines would serve the new urban development planned for the Sutter Pointe Specific Plan area in south Sutter County. However, the Measure M Group has several concerns regarding the assessment of risk to the public and the adequacy of the mitigation measures discussed in the Draft EIR to address such risks resulting from the proposal to construct and operate the new natural gas transmission pipelines. While we recognize that some effort has been made to quantify and address the risks, more can and should be done. The Measure M Group also has concerns about the construction timing and sequencing described in the EIR. As currently presented, we believe the EIR fails to fully comply with the California Environmental Quality Act (CEQA) (Pub. Resources Code, § 21000 et seq.). In the following discussion, we offer specific suggestions for additional or revised mitigation measures that we believe could address our concerns. U-1

Public Resources Code section 21002 requires agencies to adopt feasible mitigation measures (or feasible environmentally superior alternatives) in order to substantially lessen or avoid the otherwise significant adverse environmental impacts of proposed projects. (Pub. Resources Code, §§ 21002, 21081, subd. (a); CEQA Guidelines, §§ 15002, subd. (a)(3), 15021, subd. (a)(2), 15091, subd. (a)(1).) To effectuate part of this general requirement, EIRs must set forth mitigation measures that decisionmakers can adopt at the findings stage of the planning process. (Pub. Resources Code, § 21100, subd. (b)(3); CEQA Guidelines, §§ 15126, subd. (e), 15126.4.)

Mitigation measures should be capable of: (a) "[a]voiding the impact altogether by not taking a certain action or parts of an action"; (b) "[m]inimizing impacts by limiting the degree or magnitude of the action and its implementation"; (c) "[r]ectifying the impact by repairing, rehabilitating, or restoring the impacted environment"; or (d) "[r]educing or eliminating the impact over time by preservation and maintenance operations during the life of the action." (CEQA Guidelines, § 15370.) U-1 Cont.

"An adequate EIR must respond to specific suggestions for mitigating a significant environmental impact unless the suggested mitigation is facially infeasible." (*Los Angeles Unified School District v. City of Los Angeles* (1997) 58 Cal.App.4th 1019, 1029-1030.)

While an acceptable level of individual risk for hazards associated with underground pipelines has not been established by the State of California or the federal government for new development projects such as the Sutter Pointe Specific Plan, standards have been proposed and used by various governmental agencies worldwide.[1] These standards generally consider individual risk levels below 1 x 10^{-6} (one-in-a-million) acceptable.

A local community's tolerance for risk and risk acceptability needs to be taken into consideration in determining a threshold value above which individual risk levels are unacceptable. As mentioned in Item No. 9 below, the Sutter Pointe community has determined the acceptable level of individual risk to be one-in-a-million (1:1,000,000 or 1 x 10^{-6}). Accordingly, any proposal that results in a higher level of risk to the community would be deemed unacceptable by the SPSP community. U-2

Our overarching concern with this DEIR is with the estimated risk from the proposed pipeline (1:27,000), which is approximately 60 times greater than the estimated risk that is generally considered acceptable. Unless PG&E is required to take steps to decrease the likelihood of injury or fatalities from a rupture of the proposed pipeline, it is

[1] Cornwell, John B. and Meyer, Mark M., Quest6 Consultants, Inc., *Risk Acceptance Criteria or "How Safe is Safe Enough?"*, October 13, 1997.

reasonable to anticipate that adjoining residential and commercial land uses will be significantly constrained (i.e., that setbacks would be required). While one might be able to site parking lots or streets directly adjacent to the fifty-foot easement line, buildings may have to be set back significantly greater distances (perhaps tens to hundreds of feet). This could severely impact the resulting buildable areas of parcels along the pipeline. This significant issue is explained in more detail in our comments pertaining to specific pages and sections below. U-2 Cont.

1. Page ES-17, Impact No. HAZ-2: Mitigation measures should be increased to reduce the risk to acceptable levels. See our suggestions in Comment #10, below. U-3

2. Page ES-18, Impact No. LU-1: The DEIR states that the project will not conflict with SPSP; however, the unacceptable level of risk may result in the creation of no-build zones within SPSP – this would be unacceptable to Measure M Owners. (See also pages 4.9-19 through 4.9-23). U-4

3. Page 2-31, Powerline Road Main Line Valve (PRV): The location of this facility isn't clear, but it should be located on the northeastern corner of the intersection of Riego Road and Powerline Road – not southerly of Riego Road. U-5

4. Page 2-50, Giant Garter Snake Construction Scheduling: Several strategies are listed, but they could adversely impact existing rice farming operations. These impacts need to be resolved during right-of-way acquisition proceedings so that landowners can properly anticipate the impacts to their farming operations. U-6

5. Page 2-53, Trenching: The horizontal alignment and vertical profile of the pipeline need to anticipate the future location, depth and size of underground improvements within the SPSP area. The horizontal alignment and vertical profile of the pipeline should be adjusted as needed to allow future construction of the SPSP infrastructure. U-7

6. Page 2-71, Pipe Bouyancy, Line 11: The effect of a higher Factor of Safety would appear to be to "increase," not "decrease," the downward force of backfill acting on the pipe. U-8

7. Page 2-83, Operation, Maintenance, and Safety Controls: This section outlines the proposed monitoring efforts PG&E plans for the pipeline to address its potential impacts over time. Section 2.8.3 sets forth the concept of High Consequence Areas (HCA), which includes the SPSP area. This section talks about a Pipeline Integrity Management Plan. Section 2.8.4 also refers to an Emergency Response Plan. Notwithstanding the attempts in these sections to provide reassurance, a later section of the DEIR reveals that U-9

the level of risk associated with pipeline is unacceptable (see Table 4.7-5 on Page 4.7-33 which shows the annual likelihood of serious injury or fatality to be 1:27,000 for Line 407E (the section of line running through SPSP)). As stated earlier, the generally accepted level of risk is considered to be 1:1,000,000, which is consistent with the SPSP community's risk tolerance. U-9 Cont.

Also, we were unable to find either of the plans mentioned above in the DEIR. We would appreciate the opportunity for our engineering consultants to review these plans to be sure they adequately address our concerns.

8. Page 3-63, Table 3-3, Sutter County: The description incorrectly characterizes the timing of the widening of Riego Road. We understand that the current estimate is for that work to begin in 2011. U-10

9. Page 4.7-22, Sutter County General Plan: You should be aware that development standards being developed by the Measure M Group and Sutter County relating to the siting and routing of energy facilities within the SPSP area. We refer you to Section 9.5 Dry Utilities (Page 9-18 of the Specific Plan). Specific Plan Policies 9.5-8 through 9.5-11 deal specifically with natural gas facilities. The provisions of Division 15 of the Sutter Pointe Land Use and Development Code (Section XX00-1511) also require compliance with the provisions of the Specific Plan standards. While we understand that the California PUC regulates the design of natural gas facilities (and supersede local codes and regulations), these Specific Plan standards set forth the community's expectations with respect to the location of such facilities, and the level of risk the community is willing to accept. These standards specifically set the risk level at 1:1,000,000, which, as stated earlier, are generally accepted worldwide as the appropriate level of risk for the general public. PG&E's proposal does not come close to meeting these expectations. (See also, Page 4.12-16). U-11

10. Page 4.7-33, Impact HAZ-2, Table 4.7-5: This table indicates the annual likelihood of serious injury or fatality for Line 407E (the section of the pipeline in the SPSP area) at 1:27,000 or 4.93×10^{-5} (a significantly higher level of risk than generally accepted (1:1,000,000)). In fact, the level of risk proposed by PG&E is approximately 60 times greater than the generally accepted level of risk of 1:1,000,000. U-12

CEQA does not allow an agency to simply declare an impact to be significant and unavoidable without substantial evidence that mitigation to a less than significant level is infeasible. In fact, we believe additional mitigation is quite feasible and should be considered for this project to provide a more acceptable level of risk protection.

Additional mitigation measures could include increasing the wall thickness of the pipe, using a higher grade of pipe, decreasing the hoop stress of the pipeline, providing a greater depth of cover, providing more frequent inspections, increasing the frequency and type of monitoring, better cathodic protection systems, more frequent patrolling and inspections, better line marking efforts, better public education efforts, development of emergency planning and training programs, and providing a better warning to future excavators than simply a buried yellow tape lying in the pipeline trench (for example, providing a concrete cap over the pipe, encasement of the pipe with concrete, encasement of the pipe with a sand envelope, etc.). In the final analysis, the desired level of protection should be one where there is not a need for no-build zones or set-backs of habitable structure and outdoor areas on developable land within SPSP. U-12 Cont.

Further, we propose that PG&E be required to prepare individual risk assessments for all proposed land uses along the route of the proposed pipelines within the SPSP area, and to develop appropriate mitigation measures that will reduce the risk to the adjacent land uses to mutually agreeable acceptable levels. The Measure M Group, in conjunction with Sutter County, is interested in working with PG&E to address our concerns. U-13

We appreciate your consideration of our comments. We would welcome the opportunity to discuss with you further our concerns about the compatibility of the existing plans and mitigation proposed for the pipeline as they affect the planned development for the SPSP area.

Sincerely,

Sabrina Teller

Sabrina V. Teller

RESPONSE TO COMMENT SET U

U-1 The risk assessment included risk measurement terminology that was not defined in the document, which has resulted in some confusion. The Revised Final EIR provides an analysis that has been clarified to account for individual risks to the public due to the potential for fires and explosions, which may result from pipeline releases. A revised System Safety and Risk of Upset report was completed by EDM Services, Inc. for the proposed Project, and is included as Appendix H-3 of this Revised Final EIR. The EDM report findings are summarized in the Introduction to this section (Section 3.0) of the Revised Final EIR. Revisions to the Draft EIR, Section 4.7, Hazards and Hazardous Materials, and Section 4.9, Land Use and Planning, regarding the risk analysis are provided in Section 4.0 of this Revised Final EIR.

The risk analysis was revised because the aggregate risk was calculated and reported as individual risk. In addition, the risk analysis incorrectly compared the aggregate risk to the individual risk threshold of an annual likelihood of fatality of 1:1,000,000. The individual risk is defined as the frequency that an individual may be expected to sustain a given level of harm from the realization of specific hazards, at a specific location, within a specified time interval (measured as the probability of a fatality per year). Aggregate risk is the total anticipated frequency of fatalities that one might anticipate over a given time period for all of the project components (the entire pipeline system). There is no known established threshold for aggregate risk.

The individual risk significance threshold used in the EIR is an annual likelihood of one in one-million (1:1,000,000) for fatality (used by the California Department of Education for school sites). The risk level is typically determined for the maximally exposed individual (assumes that a person is present continuously—24 hours per day, 365 days per year).

The highest risk along a segment of pipeline is to persons located immediately above the pipeline, and the risk decreases as a person is farther away from the pipeline. The maximum risk posed by Line 406 before mitigation is 1:2,137,000, and after mitigation is 1:4,274,000 chance of fatality per year. The maximum risk posed by Line 407 before mitigation is 1:2,062,000, and after mitigation is 1:4,115,000 chance of fatality per year. The maximum risk posed by Line DFM before mitigation is 1:4,255,000, and after mitigation is 1:8,475,000. Because the calculated individual risk is less than the threshold of 1:1,000,000, the risk is considered to be less than significant.

The required DOT regulations, along with PG&E Project features that meet and exceed the minimum requirements, would reduce risks of project upset. Even though the project risk impacts are less than significant, additional measures would be implemented to further reduce risks of project upset. MM HAZ-2a and MM HAZ-2b have been revised. Refer to Section 4.0 of this Revised Final EIR for revisions to the Draft EIR.

The project design features and the proposed mitigation measures in the Draft EIR (MM HAZ-2a and MM HAZ-2b, as amended in this Revised Final EIR) reduce the risk by roughly 50 percent. These measures include the use of modern pipe, regular internal inspections using a high resolution instrument (smart pig), corrosion mitigation, and the installation of automatic or remotely operated shut-down valves. (See also the response to comment P-3, which provides a discussion of additional measures suggested by Hefner, Stark, and Marois.) ~~Even with the project design measures, regulations, and mitigation measures, the overall individual risk of fatality would still be approximately 1:30,000, which exceeds the individual risk significance threshold of 1:1,000,000 for serious injury or fatality (used by the California Department of Education for school sites).~~

~~Measures have been implemented to reduce the public risks. However, the lead agency recognizes that the risks remain significant even after mitigation. The CSLC will need to balance the economic, legal, social, technological, or other benefits of the proposed Project against its unavoidable environmental risks when determining whether to approve the Project. If the EIR is certified by the CSLC, a Statement of Overriding Considerations will need to be adopted at the time of certification and approval of the Project (CEQA Guidelines Section 15093).~~

Please refer to response to comment U-12 for a discussion of each specific mitigation suggested in this letter.

U-2 The individual risk significance threshold used in the Revised Final EIR is an annual likelihood of one in one-million (1:1,000,000) for fatality (used by the California Department of Education for school sites). The risk level is typically determined for the maximally exposed individual (assumes that a person is present continuously—24 hours per day, 365 days per year).

The highest risk along a segment of pipeline is to persons located immediately above the pipeline, and the risk decreases as a person is farther away from the pipeline. The maximum risk posed by Line 406 before mitigation is 1:2,137,000, and after mitigation is 1:4,274,000 chance of fatality per year. The maximum risk posed by Line 407 before mitigation is 1:2,062,000, and after mitigation is 1:4,115,000 chance of fatality per year. The maximum risk posed by Line DFM before mitigation is 1:4,255,000, and after mitigation is 1:8,475,000. Because the calculated individual risk is less than the threshold of 1:1,000,000, the risk is considered to be less than significant.

~~The individual risk criteria used by the commenter of 1:1,000,000 for serious injury or fatality is the same as that used in the Draft EIR. These criteria are outlined in Section 3.1 of the System Safety and Risk of Upset report, which was prepared by EDM Services, Inc. for the proposed Project, included as a part of Appendix H-3 of the Draft EIR.~~

~~As indicated in Table 4.7-5 of the Draft EIR, the total annual likelihood of serious injury or fatality is 1:16,000 before mitigation. The mitigation measures being imposed on the Project would reduce the risk by approximately 50 percent; however, the individual risk of serious injury or fatality would still be approximately 1:30,000, 33 times greater than the level of risk generally considered acceptable. (Please refer to page 4.7-39 of the Draft EIR.)~~

With regard to setback requirements (no-build zones) for pipelines, there are no specific set back requirements in the general plans or development codes of the affected local agencies and CPUC does not identify a setback requirement for pipelines. However, PG&E would maintain a 50-foot-wide permanent easement along the length of the Project, with the exception of the Powerline Road DFM, which would have a 35-foot-wide permanent easement. Assuming that the pipeline would be placed near the center of the easement, this would allow PG&E to restrict habitable structures from being built closer than 25 feet of the pipeline. This coupled with a minimum depth of 5 feet depth below ground surface, and 8 feet at known intersections, would minimize conflicts between the pipeline and other infrastructure construction, by burying the pipeline deeper than most other utilities.

U-3 The Revised Final EIR provides an analysis that has been clarified to account for individual risks to the public if a pipeline release were to occur with a subsequent fire or explosion. The risk assessment included risk measurement terminology that was not defined in earlier versions of the document, which has resulted in some confusion. A revised System Safety and Risk of Upset report was completed by EDM Services, Inc. (October 2009) for the proposed Project, and is included as Appendix H-3 of this Revised Final EIR.

The risk analysis was revised because the aggregate risk was calculated and reported as individual risk. In addition, the risk analysis incorrectly compared the aggregate risk to the individual risk threshold of an annual likelihood of fatality of 1:1,000,000. The individual risk is defined as the frequency that an individual may be expected to sustain a given level of harm from the realization of specific hazards, at a specific location, within a specified time interval (measured as the probability of a fatality per year). Aggregate risk is the total anticipated frequency of fatalities that one might anticipate over a given time period for all of the project components (the entire pipeline system). There is no known established threshold for aggregate risk, and it is not used in practice to determine individual risk.

The individual risk significance threshold used in the EIR is an annual likelihood of one in one-million (1:1,000,000) for fatality (used by the California Department of Education for school sites). The risk level is typically determined for the maximally exposed individual (assumes that a person is present continuously—24 hours per day, 365 days per year).

The highest risk along a segment of pipeline is to persons located immediately above the pipeline, and the risk decreases as a person is farther away from the pipeline. The maximum risk posed by Line 406 before mitigation is 1:2,137,000, and after mitigation it is 1:4,274,000 chance of fatality per year. The maximum risk posed by Line 407 before mitigation is 1:2,062,000, and after mitigation it is 1:4,115,000 chance of fatality per year. The maximum risk posed by Line DFM before mitigation is 1:4,255,000, and after mitigation it is 1:8,475,000. Because the calculated individual risk is less than the threshold of 1:1,000,000, the risk is considered to be less than significant.

Societal Risk: Societal risk is the probability that a specified number of people will be affected by a given event. Several release scenarios were used that could impact both building occupants and vehicle passengers.

The California Department of Education (CDE) approach for evaluating the risk to the student population uses two calculated parameters: an average individual risk across the depth of the campus site, and a site population risk indicator parameter. The CDE does not specify numerical criteria of acceptability or unacceptability for these indicators (CDE Guidance Protocol for School Site Pipeline Risk Analysis, 2007).

The threshold values for societal risk vary greatly, depending on the agency or jurisdiction. There are no prescribed societal risk guidelines for the United States or the State of California. The Committee for the Prevention of Disasters and the Netherlands use an annual probability of 1.0 x 10^{-3} (1:1,000) or less. This criterion has been used to evaluate the proposed project.

The societal risk posed by the proposed project is less than the significance threshold of 1:1,000 or less.

~~The level of risk posed by Line 407E before mitigation is 1:27,000, 37 times greater than the level of risk generally considered acceptable. After mitigation, the level of risk posed by Line 407E would be approximately 1:40,000, 25 times greater than the level of risk generally considered acceptable. The level of individual risk for the entire proposed Project is presented above, in the response to comment U-2.~~

The commenter cited the following additional mitigation measures, which could be imposed to reduce the level of risk. As noted above, the revised risk analysis shows that the individual risk is less than significant before mitigation. ~~In addition~~ To reduce the risk further, many of these additional mitigation measures have already been incorporated into the Project, as ~~noted~~ listed below:

- Increase the Pipe Wall Thickness - The pipe as proposed has adequate thickness to resist damage from construction equipment beyond the size normally used in general construction. PG&E has proposed, as a part of their Project, to install the pipeline to meet or exceed the current pipeline regulations (49 CFR 192). Thick-walled steel pipelines are typically used for extreme conditions such as subsurface sea floor lines or risers. During the manufacturing of thick-walled steel pipelines, the cooling rate at the time of quenching of the pipe becomes slow, particularly at the central portion due to its thickness, resulting in insufficient strength and toughness. This is because the cooling rate is slow, and there is a high probability that the pipe will be brittle. As provided in the Project Description and on pages 4.7-36 and 4.7-37 of the Draft EIR, the following pipe wall thickness is proposed for the Project:

    - For Class 1 areas, the minimum regulated pipe wall thickness is 0.3125-inch; 0.375-inch wall thickness pipe is proposed, 20% greater than the minimum required.

- For Class 2 areas, the minimum regulated pipe wall thickness is 0.375-inch; 0.406-inch wall thickness is proposed, 8% greater than the minimum required.

- For Class 3 areas, the minimum regulated wall thickness is 0.4875-inch; 0.500-inch wall thickness is proposed, 3% greater than the minimum required.

  The additional wall thickness will provide added strength. For example, the 0.375-inch to 0.406-inch thick pipe wall would resist a 73-ton machine and the 0.500-inch thick pipe wall would resist a 120-ton machine. As noted on page 88~~ 57 of~~ the revised System Safety and Risk of Upset report, which was prepared by EDM Services, Inc. (October 2009) for the proposed Project and is included as ~~a part of~~ Appendix H-3 of ~~the Draft~~ this Revised Final EIR, “For 24-inch diameter pipe, a wall thickness of 0.375-inches or greater was found to reduce the frequency of third party caused unintentional releases by 80 percent.”

- Higher Grade Pipe - PG&E has proposed using API 5L X-60 and X-65 pipe. These pipe materials have specified minimum yield strengths of 60,000 psi and 65,000 psi, respectively, and are at the upper range of pipe grades typically used for transmission pipelines. For reference, API 5L Grade B pipe, with a specified minimum yield strength of 35,000 psi, is commonly used for pipeline construction. Pipes with higher yields strengths than those proposed can suffer from metallurgical issues including excessive hardness, cracking, difficulty in welding, etc.

- Decreased Hoop Stress - The California Hazardous Liquid Pipeline Risk Assessment (Payne, Brian L. et al. EDM Service, Inc. 1993. California Hazardous Liquid Pipeline Risk Assessment, Prepared for California State Fire Marshal) studied the effect of operating pressure and hoop stress as a percentage of the specified minimum yield strength of the pipe. The study found that there was no statistical correlation between stress level or operating pressure and the likelihood that a pipe would leak or rupture. Although the study found that pipes operated at higher pressures and stress levels were actually less prone to leakage, these differences disappeared once other variables, such as pipe age and operating temperature were controlled in the logistic regressions.