03-14-11P01:50 RCVD

PXP

Plains Exploration & Production Company

March 11, 2011

Mr. Chris Hoidal, P.E.
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
12300 W. Dakota Ave, Suite 110
Lakewood, Colorado 80228

RE: Response to Notice of Amendment CPF 5-2011-7002M

Dear Mr. Hoidal,

Plains Exploration & Production Company (PXP) has reviewed the "NOTICE OF AMENDMENT (NOA), CPF No. 5-2011-7002M. The NOA is a result of an integrity management inspection on October 13-15, 2010 at PXP's offices in Los Angeles California.

We have addressed the items of concern noted in the NOA.

(1) NOA States:

"195.452 Pipeline integrity management... Plains Exploration & Production Company (PXP) has a 10,000 barrel breakout tank in its Gaviota Processing Plant which is located in a High Consequence Area (HCA). However, this breakout tank is not included in the IMP segment identification. PXP must include this breakout tank in its IMP and integrate all available information about integrity of the tank and the consequence of its failure..

PXP Response:

Shipping Tank T-1 (10,000 bbl) at the Gaviota Oil Heating Facility (GOHF) is now designated as a break out tank and is located in an HCA. However, the tank is not a threat to the HCA and does not need to be included in the IMP segment identification. Released liquids cannot reach the HCA as the tank is within secondary containment as described in section 5.3.2 (attached) from the GOHF Spill Prevention, Control, and Countermeasure (SPCC) Plan. Table 5-1 "Bulk Oil Storage Tank and Containment" from the SPCC (attached) lists the volume of the containment structure Impound S-8 as 44,000 bbls. Impound S-8 is listed as four times the volume of T-1 and it is where T-1 drains to in the event of a release. This does not allow a release from T-1 to enter the HCA. The attached Site Plan sheet number 00-A-61043 shows in blue the drainage area, which includes T-1 and T-2, that drain into impound S-8.

(2) NOA States:

195.452 Pipeline integrity management... Plains Exploration & Production Company (PXP) did not include the anchoring of boats over its offshore pipelines from platforms

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Irene and Hermosa to shore as a risk factor in the IMP assessment. PXP must base the assessment schedule on all risk factors that reflect the risk conditions on its offshore pipeline segments and evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area.

PXP response:

Boat anchoring for offshore facilities has been included as a minimum risk factor In PXP's Hazardous Liquid Integrity Management Plan Element #2 "Baseline Assessment" Section 2.7 "Risk Factors for Establishing Assessment Schedule" and Element #5 "Continuing Assessment & Risk Analysis" Section 5.4 "Re-assessment Intervals" .

Section 2.7 from Element #2 and Section 5.4 from Element #5 have been attached for your review.

PXP believes these actions satisfy the PHMSA NOA concerns. Should you have any questions, please contact Mr. Bob Marsalek at (805) 934-8223,

Sincerely,

David Rose
Manager, Environmental, Health and Safety

- Steel forging to ASTM standard A66B CL, C, CH E, or F
- Bolts and nuts to ASTM standard A325
- Flanges to ANSI B31.3 and B16.5
- Gaskets are flexible graphite filled 0.175" thick, spiral wound per API standard 601 with type 304SS windings and carbon steel outer compression ring
- Platform floor plates painted with non-skid surface.

The storage tanks are fully coated. The tanks are equipped with anodes to prevent electrolytic corrosion.

5.3.2 Secondary Containment – 112.8(c)(2)

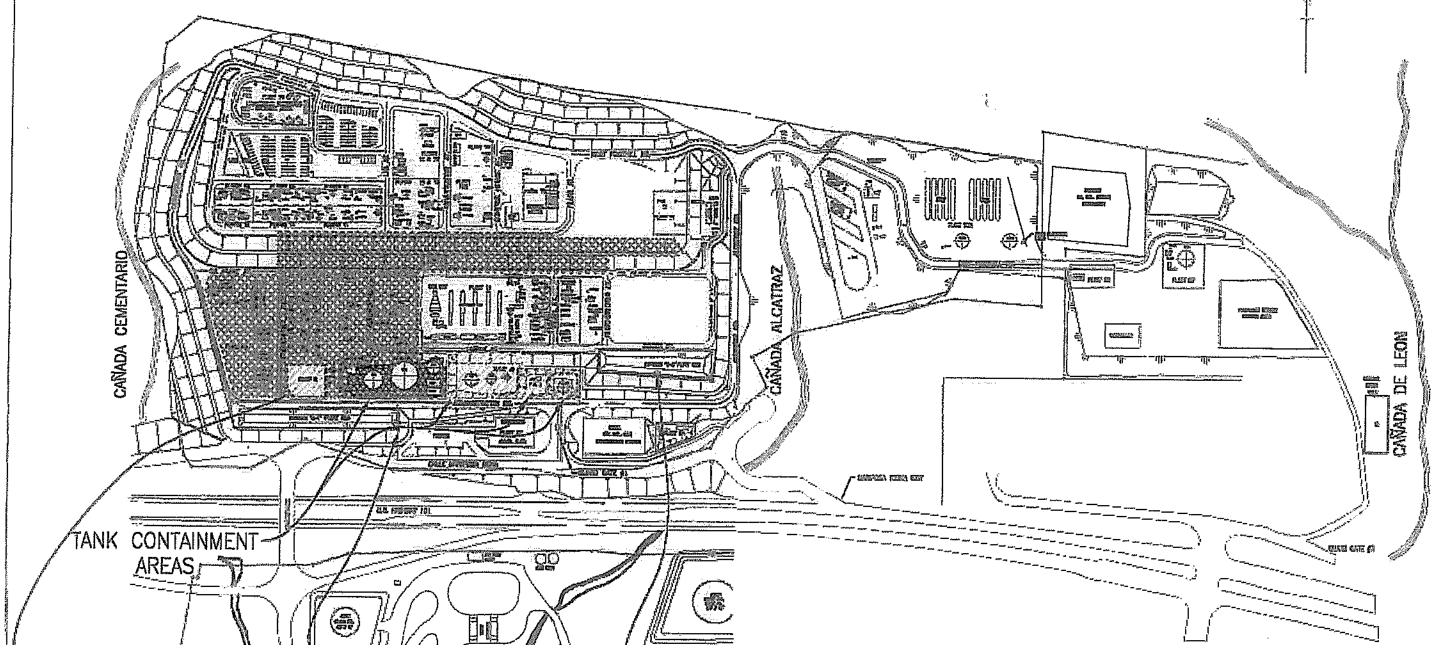
Specific information on secondary containment is included on Table 5-1. Secondary containment is provided by impervious dikes around the aboveground storage tanks containing petroleum. Secondary containment structures are designed to provide capacity for the entire contents of the largest single tank plus freeboard to allow for precipitation from a 100-year storm event. The secondary containment for T-2 consists of a concrete masonry wall approximately 2-feet high and impound S-8. The secondary containment for T-8 consists of earthen slopes and a concrete masonry wall approximately 2.3-feet high along the east and southeast sides. The secondary containment for T-25 consists of a concrete masonry wall approximately 5 feet high at its lowest point.

T-4, T-6, T-7 are no longer being used. T-1, T-4 are within the containment area for T-2.

Table 5-1. Bulk Oil Storage Tank and Secondary Containment

Container Designation	Type of Failure	Maximum Volume	Maximum Discharge Rate	Direction of Flow	Containment Structure – Containment Capacity
T-1	rupture, leak	10,000 bbls	5,000 bbls/hr	west	S-8 – 44,400 bbls
T-2	rupture, leak	40,000 bbls	20,000 bbls/hr	west	S-8 – 44,400 bbls
T-4*	OOS	5,000 bbls	--	west	S-8 – 44,400 bbls
T-6*	OOS	2,000 bbls	--	southwest	S-1 – 40,000 bbls
T-7*	OOS	500 bbls	--	southwest	S-1 – 40,000 bbls
T-8	rupture, leak	3,000 bbls	1,500 bbls/hr	southwest	S-1 – 40,000 bbls
T-25	rupture, leak	1,300 bbls	650 bbls/hr	southwest	S-1 – 40,000 bbls
D-201A	rupture, leak	752 gals	350 gals/hr	south	S-1 – 40,000 bbls
D-201B	rupture, leak	752 gals	350 gals/hr	south	S-1 – 40,000 bbls
D-201C	rupture, leak	752 gals	350 gals/hr	south	S-1 – 40,000 bbls
D-603A	rupture, leak	752 gals	350 gals/hr	south	S-1 – 40,000 bbls
D-603B	rupture, leak	752 gals	350 gals/hr	south	S-1 – 40,000 bbls
J-202	rupture, leak	420 gals	210 gals/hr	south	S-1 – 40,000 bbls
J-604	rupture, leak	420 gals	210 gals/hr	south	S-1 – 40,000 bbls
E-3B	rupture, leak	1306 gals	650 gals/hr	south	S-1 – 40,000 bbls
E-3C	rupture, leak	1306 gals	650 gals/hr	south	S-1 – 40,000 bbls
V-1000	rupture, leak	440 bbls	220 bbls/hr	south	S-1 – 40,000 bbls
V-1001A	rupture, leak	1854 bbls	900 bbls/hr	south	S-1 – 40,000 bbls
V-1001B	rupture, leak	1854 bbls	900 bbls/hr	south	S-1 – 40,000 bbls
V-50	rupture, leak	757 bbls	350 bbls/hr	south	S-1 – 40,000 bbls
V-51	rupture, leak	940 gals	450 gals.hr	south	S-1 – 40,000 bbls

GAVIOTA OIL HEATING FACILITY
CONTAINMENT & DRAINAGE SYSTEM



DRAINAGE INTO IMPOUND S-1

THIS AREA MAY BE DIVERTED TO TO IMPOUND S-1 (A)

DRAINAGE INTO IMPOUND S-8

DRAINAGE INTO IMPOUND S-2 (B)

PERIMETER ROADS AND OFF-PLOT DRAINAGE DRAIN INTO CAÑADAS

REVISIONS			
0 REDRAWN ON CAD	4/21/98	LL	JJPE

PXP

SITE PLAN
STORM WATER DRAINAGE SYSTEM
GAVIOTA OIL AND GAS PLANT
SANTA BARBARA COUNTY, CALIFORNIA

SCALE AS SHOWN DATE 4/21/98

A C.C. UC290G80Y W.O. 9700586

00-A-61043 SHEET 1 0

DR LUKE CH.
DR APP.
ENGR. JJPE
OPR'G. DEPT. APPROVED
ENG'R. DEPT. JJPE

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Minimum Risk Factors for Establishing Frequency of Assessment

The Company will use the following list of risk factors for establishing frequency of assessment.

1. Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.
2. Results from previous assessments, testing/inspection. [195.452(h)]
3. Leak history.
4. Known corrosion or condition of pipeline. [195.452(g)]
5. Cathodic protection history.
6. Type and quality of pipe coating (disbonded coating results in corrosion).
7. Age of pipe (older pipe shows more corrosion–may be uncoated or have an ineffective coating) and type of pipe seam.
8. Product transported (highly volatile, highly flammable and toxic liquids present a greater threat for both people and the environment).
9. Pipe wall thickness (thicker walls give a better safety margin)
10. Size of pipe (higher volume release if the pipe ruptures).
11. Local environmental factors that could affect the pipeline
    - Geo-technical = seismic faults, landslides, subsidence, and soil condition
    - Climatic = permafrost, etc
    - Corrosivity of soil
12. Security of throughput (effects on customers if there is failure requiring shutdown).
13. Time since the last internal inspection/pressure testing.
14. Previously discovered defects/anomalies, including type, growth rate, and size.
15. Operating stress levels in the pipeline.
16. Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).
17. Physical support of the segment such as by a cable suspension bridge.
18. Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).
19. Other regulatory interval requirements
20. Construction activity in the area.
21. General health and safety factors (employees and public)
22. Environmental impacts
23. Property damage
24. Local economic impact
25. Alternate modes of operation (startup, shutdown, shut-in, slack line, pressure cycling, etc.)
26. Other segment specific factors as determined by the Company, for example boat anchoring for offshore facilities

Other factors considered in the analysis will include information analysis, decisions about remediation, and preventive and mitigative actions.

The IMP records binder/files contains the baseline assessment schedule. This schedule identifies the pipeline segments affecting HCAs, assessment method, risk ranking, and scheduled assessment dates.

The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed, not including repair activities. That will be when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed, or the date on which "other technology" for which an operator has provided timely notification is conducted. Evaluation of the assessment results, integration of other information, and repair of anomalies must still be performed in accordance with the requirements established for these activities in the rule. These activities are considered to occur after the completion of the "assessment".

The Company will consider all risk factors relevant and specific to a particular pipeline segment. This includes risk factors that influence both the <u>likelihood</u> and the <u>consequences</u> of pipeline failure.

Re-assessment intervals will be based on the following:

1) All risk factors associated with the pipeline and adequately consider the risk factors listed in §195.452 (e), see list below
2) Re-assessment intervals that consider analysis of results from the last integrity assessment
3) Re-assessment intervals that are determined using all information obtained on the condition of the pipeline as required by §195.452 (g)

The primary element of risk management includes a dynamic framework that continually changes to reflect operating experience and conclusions drawn from previous assessments. This information would include design and construction information, maintenance and surveillance activities, operating parameters and operating history, right-of-way information, information about the population and the environment near the pipeline, and industry operating experience. The rule specifically identifies several risk factors that should be considered. The Company will include these factors in their risk analysis along with segment specific risk factors. See minimum factors used in risk analysis below.

Minimum Risk Factors for Establishing Frequency of Assessment

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6. Type and quality of pipe coating (disbonded coating results in corrosion).
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23. Property damage
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25. Other segment specific factors as determined by the Company, for example boat anchoring for offshore facilities.

Other factors considered in the analysis will include information analysis, decisions about remediation, and preventive and mitigative actions.

Risk is an inherent part of life and is associated with pipeline activities. While the overall risk of an operating pipeline can be managed, changed, or possibly reduced, it cannot be reduced to zero. Understanding risk factors is an important part of an IMP, because it is used to identify mitigation strategies. The total risk for a particular pipeline segment is the summation of the risks from the various threats to that segment.

5.5 Risk Analysis Methodology

The regulation allows the Company to select the appropriate risk analysis methodology. The Company will utilize the risk analysis methodology shown in the IMP records binder/files which addresses both the likelihood and consequence for each appropriate threat and associated risk factors.