



June 19, 2015

The Honorable Barbara Boxer
The Honorable Dianne Feinstein
The Honorable Edward J. Markey
United States Senate
Washington, D.C. 20510

The Honorable Lois Capps
United States House of Representatives
Washington, D.C. 20515

RE: Response to Letter Dated June 5, 2015

Dear Senators Boxer, Feinstein and Markey and Congresswoman Capps:

In response to your letter dated June 5, 2015, Plains All American Pipeline shares your interest in determining the cause of the breach in Line 901 and applying that information to help prevent similar accidents from recurring in the future. We sincerely regret the impact that this unfortunate release has had on the environment and wildlife along the Central Coast and its residents and visitors. In conjunction with the other members of the Unified Command, we have made meaningful progress toward cleanup, and Plains will continue to do what it takes to complete this work and to make things right.

With respect to the written questions that were included in your letter, attached please find our responses. Consistent with the tenor of the discussions I was fortunate to have with certain of you and your staff members recently in Washington, D.C., we have responded in a candid and open manner, recognizing that in a few instances our responses are necessarily constrained by the fact that there are ongoing investigations.

Please don't hesitate to contact me if you have any additional questions or would like any additional information. I would welcome the continued dialogue.

Best regards,

Greg L. Armstrong
Chairman & CEO
Plains All American Pipeline, L.P.

Enclosures

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- 1. Please provide an unredacted copy of Plains Pipeline's spill response plan for Line 901. When was this spill response plan approved by PHMSA? What is the maximum spill detection and shutdown time for Line 901 outlined in the spill response plan approved by PHMSA?**

Attached is a copy of our spill response plan (the "SR Plan") for the Plains Bakersfield District (Santa Barbara, San Luis Obispo and Kern Counties), which contains over 700 pages of detailed information. We respectfully note that our SR Plan includes certain sensitive information that, due to security concerns voiced by the pipeline industry and others, is considered inappropriate or unwise to make widely available. With those considerations in mind, we have provided a copy of the SR Plan that has been redacted to protect personal information, customer and vendor information and certain security sensitive material. Our objective is to be as transparent and responsive as practical within these constraints. However, if after reviewing the plan you determine that you would like to review any of the redacted information, we are certainly open to discussing how best to make that information available to you in a manner that addresses the applicable security and other concerns.

Our records indicate that the SR Plan was approved by PHMSA on February 7, 2014. As set forth in the SR Plan, our estimate of the maximum detection and shut down time for Line 901 is fifteen (15) minutes.

- 2. According to the original corrective action order issued by PHMSA, Plains Pipeline employees detected anomalies in Line 901 at 11:30 a.m., discovered the failure at 1:30 p.m. and reported the incident to the National Response Center at 2:56 p.m. While we understand that this question may be part of PHMSA's investigation, please provide whatever information you have as to why this release of oil was not reported to the National Response Center for 1 hour and 26 minutes after it was visually confirmed by Plains employees and 3 hours and 26 minutes after anomalies were first detected?**

The sequence of events on the day of the release is being thoroughly analyzed and evaluated by PHMSA, and we are fully cooperating with PHMSA by providing it with requested information (including a full record of the second-by-second data from our Supervisory Control and Data Acquisition system (SCADA)), answering questions and making our employees available. In deference to the ongoing PHMSA investigation and other fact gathering efforts, it would be premature and inappropriate for us to provide detailed responses regarding the timeline at this time or attempt to draw any conclusions therefrom. However, as we discussed during our meetings in Washington DC with certain of you or members of your respective staff and in order to be responsive to your question, we provide below the following timeline information compiled from the Joint Timeline prepared by the Unified Command, timeline notes prepared by a representative of the Santa Barbara Office of Emergency Management ("SBC OEM") and Plains Pipeline information (all times PDT):

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- a) The Las Flores pump (located upstream of the release point at the origination point for Line 901) was remotely shut down by Plains Midland control room at approximately 11:30 a.m., which was approximately 12 minutes before the Santa Barbara County Fire Department (“SBFD”) received a 911 call regarding an odor (additional information regarding the basis for the shutdown is set forth in the answer to question #3 below);
- b) Just after noon, State Parks staff were alerted to the 911 call and attempted to locate the source of the odor; State Parks and SBFD staff met at Refugio State Beach, began to search and observed a sheen on the water;
- c) At around the same time, representatives from Plains Pipeline, the SBC OEM and the SBFD were attending a previously scheduled spill drill hosted by Freeport McMoran; the drill began with an initial briefing at the offices of the SBFD and then moved to Freeport McMoran’s Gaviota station;
- d) Shortly before 12:30 p.m., SBFD personnel notified the SBC OEM representative at the spill drill that oil was on the beach just north of Refugio Beach, the drill was cancelled and representatives of Plains Pipeline and the SBC OEM traveled to the beach;
- e) According to the National Response Center (“NRC”) records, the NRC received notification of the spill at 12:43 p.m.; the California Office of Emergency Management received notice of the spill from the SBFD at approximately the same time; shortly thereafter, representatives from Plains Pipeline and the SBC OEM visually confirmed there was oil on the water;
- f) Once Plains Pipeline and SBC OEM personnel confirmed that there was oil on the water, two Plains Pipeline employees left to ride the Line 901 right of way to determine if Line 901 was the source of the released oil. It was not readily apparent from their vantage point near the beach that the oil originated from Line 901; the line is located up-slope on the other side of the highway and railroad tracks, and oil was not seen running down the slope, across the highway or across the railroad tracks. As discovered later, there was a culvert located near the pipeline very near the point of release and oil traveled under the slope, highway and railroad tracks.
- g) At approximately 1:25 to 1:30 p.m., the Plains Pipeline employees confirmed that the release originated from Line 901. After calling Plains’ Midland control center to confirm the spill, both employees made various calls by cell phone to mobilize resources, make notifications and coordinate activities. In addition, one of the Plains employees attempted to build a makeshift berm with his shovel to prevent additional oil from getting to the culvert and was subsequently assisted in this effort by SBFD personnel.
- h) Plains Pipeline personnel in the Bakersfield office also began to make notifications to regulatory agencies, and it appears that several of these

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calls duplicated the notifications made by other responding agencies. To properly notify the NRC, Plains Pipeline personnel needed to have the location coordinates and an estimate of the volume of oil released. While the on-site Plains personnel were busy dealing with the immediate demands and distractions associated with the response, the Plains personnel in the Bakersfield office were not able to reach the on-site employees to get a volume estimate, but they were able to determine the location coordinates. At 2:56 p.m. a Plains Pipeline Bakersfield employee called the NRC and formally notified them of the coordinates of the release and, despite being unable to get through to the on-site Plains employees, gave a volume estimate of approximately 500 barrels (equivalent of approximately 21,000 gallons). This contact was in addition to the initial contact received by the NRC at approximately 12:43 p.m. according to NRC records.

- 3. According to documents provided by your company, a Plains Pipeline Control Room employee saw abnormalities in the line and shut it down at approximately 11:30 a.m. However, subsequent reports note that Control Room operators originally shut down pumps on the line, restarted them about 20 minutes later, and shut down the pumps again after finding the pumps had failed. When did Plains Pipeline personnel first discover abnormalities in Line 901? How long after first discovering these abnormalities was Line 901 shut down (both initially and permanently)? Why did you resume pumping when there was potentially a larger problem, and who approved the restart of Line 901? What factors contributed to the decision to shut down the line a second time?**

As we discussed during our meetings the week of June 8 in Washington DC with certain of you or members of your respective staffs, on the morning of May 19, during routine maintenance of an idled pump we experienced an unplanned shutdown of the operating pump at our Sisquoc station located approximately 45 miles downstream of the release location. The Las Flores pump continued to operate for several minutes and line pressure increased before it was shutdown. Shortly thereafter, the issues with the Sisquoc pump were resolved, the Las Flores pump was restarted and the command to restart the Sisquoc pump was sent. Approximately 20 minutes later, at approximately 11:15 a.m. PDT, the Sisquoc pump shut down and was not able to be restarted. Approximately 15 minutes later, the Las Flores pump was shut down. Approximately 37 minutes elapsed between the restart of the Las Flores pump and the final shutdown of the Las Flores pump at approximately 11:30 a.m. PDT.

As indicated above, the sequence of events on the day of the release is being thoroughly analyzed and evaluated by PHMSA, and we are fully cooperating with PHMSA by providing it with requested information (including a full record of the second-by-second data from our SCADA system), answering questions and making our employees available.

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4. **According to documents provided by your company, an employee traveled to the site and visually confirmed the release of oil at 1:30 p.m. While we understand that this question may be part of PHMSA's investigation, please provide whatever information you have as to why it took roughly two hours to visually confirm the existence of a release of oil?**

Please see the response to Question 2 above for a summary description of activities that took place between 11:30 a.m. and 1:30 p.m. PDT.

5. **According to PHMSA, the affected pipeline was recently inspected using a smart pig on May 5, 2015, but the report had not yet been provided to Plains Pipeline at the time of the incident. How long does Plains Pipeline typically provide for vendors performing in-line inspections to provide a report of the results, which may show corrosion or other anomalies that could potentially lead to spills? Please provide a copy of the final results of this in-line inspection report either accompanying your response to this letter or when it is provided to you.**

Plains Pipeline typically requires in-line inspection ("ILI") service providers to issue a preliminary report within 30 calendar days, and a final report within 60 calendar days, following completion of the inspection. After the release occurred on May 19, Plains requested an expedited preliminary and final report from the third party vendor that performed the May 5 inspection. The preliminary report was received on May 28, 2015 and the final report on June 5, 2015.

With respect to your request for a copy of the final results of the in-line inspection report, we have established an online portal for representatives of PHMSA to review the final ILI report, and we would be happy to discuss granting similar privileges to you or members of your respective staffs.

6. **Preliminary results from your May 5 inspection reported corrosion metal loss of 45 percent in the area of the rupture, but third party investigators have revealed that 82 percent of the pipe's thickness had actually worn away (down to 1/16 of an inch) instead. Please explain how there can be such large inconsistencies in these measurements. Does the inconsistency of these measurements raise further concern for the safety of the remainder of this pipeline and other pipelines that you operate in the area?**

PHMSA's Amendment #1 to the Corrective Action Order stated that:

"...Third-party metallurgists in the field estimated that corrosion at the Failure site had degraded the wall thickness to an estimated 1/16 of an inch (.0625"). This thinning of the pipe wall is greater than the 45% metal loss which was indicated by the recent ILI survey."

To our knowledge, neither the metallurgist nor PHMSA performed actual physical measurements of the wall thickness of the affected pipe in the field. The coating and debris would have to be removed and the pipeline would have to be cleaned before an

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accurate measurement could be obtained. To our knowledge, this work was not performed in the field, and the affected pipe was excavated, placed in a box, sealed and transported to a third-party laboratory for evaluation and testing. Accordingly, although we are aware of the above reference to a field estimate, as of the current date, neither PHMSA nor the third party conducting the evaluation and testing of the affected segment of pipe has provided us with their measurements of the metal loss or wall thickness, and until that information is made available, we are not in a position to make any statements about “inconsistent measurements” or draw any conclusions about implications for other pipelines that we operate.

We would like to note that the reports from the May 5, 2015 ILI tool run indicated four locations that required further investigation. With PHMSA inspectors observing as noted in Amendment No. 1 to the Corrective Action Order, Plains Pipeline’s field crews excavated three of these locations between May 29 and June 3. The fourth location has since been excavated and repaired. The actual metal loss at each of these four locations, as determined by physical inspections and measurements in the field, revealed an acceptable correlation with the metal loss measured by the tool run. In all four cases, the actual metal loss was less than the loss estimated in the report from the tool run.

- 7. Please confirm that Line 901 was not outfitted with an automatic shut-off sensor system. If such a system was not in place, will Plains Pipeline be installing such a system on Line 901 after the pipeline is excavated, inspected, and replaced? If not, why not?**

Line 901 is equipped with remotely controlled valves (“RCVs”) and check valves (valves that allow liquid product to flow in one direction, but automatically prevent flow in the opposite direction). RCVs allow an operator to remotely open and close valves with the push of a button from a control room and do not require a person to be dispatched to the site to open or close a valve. Applicable federal regulations (CFR 195.452) require operators of hazardous liquids pipelines to evaluate the use of RCVs and check valves (defined in the regulations as Emergency Flow Restricting Devices (“EFRDs”)) on hazardous liquids pipelines operating in high consequence areas (“HCAs”).

Please note that applicable federal regulations do not require operators of hazardous liquids pipelines in HCAs to evaluate the use of automatic shut-off valves (“ASVs”); however, such regulations do require natural gas pipeline operators to consider the use of ASVs (see CFR 192.935).

As additional background, according to a Pipeline Safety report issued by the GAO in January 2013 (GAO-13-168), which discussed the use of ASVs by operators of liquids pipelines:

“...For hazardous liquid, all operators we [GAO] spoke with stated that they either do not consider or do not typically install automatic-shutoff valves because an accidental closure has the potential to lead to an incident. Specifically, operators stated that an unexpected valve closure can result in decompression

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waves in the pipeline system, which might cause the pipeline to rupture if operators cannot reduce the flow of product promptly.”

Similarly, an Oakridge National Laboratory study in October 2012 acknowledged that inadvertent valve closures could cause a pressure surge and could damage the pipeline.

Plains Pipeline shares the view that the use of ASVs on liquids pipelines could cause unintended consequences, and accordingly does not expect to use ASVs on Line 901 after the affected segment is replaced.

- 8. According to information on Plains Pipeline’s website, your company operates 17,800 miles of active crude oil and natural gas liquid pipelines and gathering systems in the United States and Canada. How many miles of crude oil and natural gas liquid pipelines and gathering systems does Plains Pipeline operate in the United States? How many of these pipelines in the United States are equipped with automatic shut-off valves?**

In its transportation segment, Plains All American (“PAA”) owns approximately 17,800 miles of crude oil and natural gas liquid pipelines in the United States and Canada, including approximately 10,700 miles of crude oil and natural gas liquid pipelines that we operate in the United States. PAA also operates approximately 1,100 miles of pipelines in its facilities segment, for a combined total of 18,900 miles of pipelines on a company-wide basis. For the reasons stated in our response to Question 7 above, none of these pipelines that transport crude oil or other liquids are equipped with ASVs.

- 9. According to news reports, your company has had one of the worst safety records of any pipeline company, with 175 safety and maintenance violations since 2006 that have spilled more than 16,000 barrels of oil that have caused more than \$23 million worth of property damage. Please provide the amount of money Plains Pipeline has spent on pipeline safety improvements in each year for the past 10 years and any additional steps Plains Pipeline is taking to improve safety on the pipelines it operates.**

Plains Pipeline has in fact reported 175 incidents to PHMSA since 2006, but the reported incidents are not “safety and maintenance” violations. They are releases that occur on both pipelines and within our facilities, and include releases as low as five (5) gallons, even if such releases were captured in containment areas designed for such purpose. It is worth noting that although Plains Pipeline’s 175 reported incidents ranked high among the approximate 1,750 reporting entities in the data set referenced by media reports, based on reported pipeline miles Plains Pipeline is larger than approximately 99% of all reporting entities.

To provide a full and transparent analysis of our history of releases, included in Exhibit A is an analysis of our historical performance based on the data set that includes the 175 releases referenced in the media reports we understand are being referred to in your

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question. In total, there are 229 incidents since 2006; this amount includes the 175 incidents related to Plains Pipeline as well as incidents related to other PAA related entities that operate liquids pipelines included in the corresponding data set. In Exhibit A we have categorized and separated the incidents to those related to our pipelines and those related to our facilities. Incidents on our pipelines pose the greatest risk of impacting third party property and the environment, while releases at our facilities typically only impact our property. The graphs on Exhibit A show a significant reduction in pipeline related incidents; such incidents have declined by 74% since 2006, and incidents involving five (5) or more barrels have declined by approximately 82%. We acknowledge that facilities related incidents have increased; however, we are implementing programs to address these releases, which are typically lower risk incidents that for the most part only impact our property.

We also note that the volume of approximately 16,000 barrels released only includes Plains Pipeline incidents. If we more broadly include all PAA related entities that operate liquids pipelines included in the corresponding data set, the volume released since 2006 is approximately 19,700 barrels, and approximately 9,700 of such barrels were released in 2006. Thus, since 2007 the volumes released were approximately 10,000 barrels. Approximately 5,100 barrels of such 10,000 barrels released related to our pipeline assets, and the remaining 4,900 barrels related to our facility assets.

We also note that the \$23 million of property damage reported by Plains Pipeline consisted largely of costs that reflect the economic impact to us, including property damage to our facilities, the value of lost commodities, the cost to repair and replace our facilities and cleanup costs on our property. The balance of the \$23 million consists of damage to third party property, including the cost to remediate impacted soils and/or waters on property owned by third parties.

PAA has number of programs in place to assess, maintain and improve the integrity of our assets, many of which are above and beyond those necessary to meet minimum regulatory compliance. Exhibit B attached hereto includes a brief description of these programs and Exhibit C shows the amount of maintenance and integrity expenditures that PAA has incurred in each of the last ten years from 2005 to 2014, which total \$2.4 billion. These amounts do not include expansion capital expenditures we have made that enhance the overall integrity of our asset base; examples of such expenditures include projects to replace or parallel pipelines that have been de-rated and are being operated at lower operating pressures, valve installations and horizontal directional drilling projects. For the ten year period from 2005 to 2014, such amounts totaled approximately \$400 million.

- 10. In 2010, the U.S. Environmental Protection Agency and Justice Department announced that Plains would spend approximately \$41 million on upgrades to oil pipelines operated in the United States, stemming from Clean Water Act violations for oil spills in Texas, Louisiana, Oklahoma, and Kansas. Please provide a complete description of how these funds were allocated and whether any of these funds were**

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used to upgrade the Line 901 pipeline near Santa Barbara, or any other pipelines operated by Plains within the State of California. If these funds were used to upgrade Line 901 or other pipelines in California, please describe what upgrades were made and the pipelines involved.

As detailed below, none of the \$41 million in funds that PAA committed to spend pursuant to the Consent Decree were used to upgrade Line 901, but some of the funds were spent on other pipelines operated by Plains within the State of California.

Prior to 2007, PAA made a number of acquisitions, and many of the acquired pipelines were gathering pipelines and pipelines that were not subject to PHMSA's integrity management ("IMP") regulations. PAA developed its own risk screening program ("RSP") to identify threats associated with any such acquired pipelines that were not subject to PHMSA's IMP regulations and to develop risk mitigation strategies. For the most part, the Consent Decree required PAA to implement the RSP within PAA's proposed timeline – essentially mandating that we implement plans that were already identified and in progress. PAA estimates that the cost associated with the RSP program accounts for a range of \$24 million to \$29 million of the \$41 million PAA committed to expend pursuant to the terms of the Consent Decree. In the last ten years, PAA has taken over 6,200 miles of pipelines out of service as a result of the RSP. Since Line 901 is subject to PHMSA's IMP regulations, the RSP did not apply to Line 901. However, the RSP was implemented with respect to gathering pipelines in Kern County, California, and approximately eight miles of these pipelines have been taken out of service as a result of the RSP.

Pursuant to the Consent Decree, PAA also was required to spend no less than a total of \$6.0 million during 2010 and 2011 on activities we had identified to mitigate threats posed by corrosion on pipelines; approximately \$3.7 million of this cost was attributable to pipelines not covered by PHMSA's IMP regulations and thus were counted towards PAA's \$41 million commitment under the Consent Decree. The corrosion mitigation activities undertaken included: (i) replacement or installation of no fewer than 120 anode beds and/or rectifiers; (ii) installation of equipment to inject corrosion inhibitor and biocides for internal corrosion control, and (iii) performance of close interval surveys ("CIS") (a test of the cathodic protection system) on no fewer than 2,400 miles of pipeline. None of these costs related to Line 901, as these activities were already in place for Line 901. Our gathering assets in Kern County, California were included in this corrosion mitigation program. In addition, in Amendment No. 1 to the CAO, PHMSA acknowledged that there were adequate levels of cathodic protection at the sites where external corrosion was identified on Line 901. We also note that PAA conducted CISs in 2008 and in 2015 (testing in progress) on Line 901.

Approximately \$3.0 million of the \$41 million commitment related to a requirement to provide computational pipeline monitoring ("CPM") capabilities on 110 segments of pipeline. Eighty segments were identified specifically in Appendix B of the Consent Decree, including Line 901 and other lines in California, with an additional 30 segments

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identified by PAA to be completed by December 31, 2011. PAA was also required to have all 110 segments comply with the performance standards for CPM in API 1130.

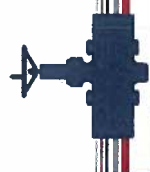
Approximately \$9.0 million (\$3.0 million per year for a three year period) was related to a requirement for PAA to preserve and staff the following employee positions until at least July 31, 2011, which positions benefited all of our assets in the United States:

- PHMSA/IMP Records Coordinator and five records specialists;
- Pipeline Integrity Coordinator for Non-PHMSA Regulated Pipelines;
- Pipeline Integrity Coordinator for Internal Inspection;
- Senior Measurement and Quality Control Manager;
- Pipeline Control Center Training Supervisor;
- Control Center Shift and Console Supervisors;
- One Call Administrator; and
- Two Leak Detection Engineers.

We also note that the Consent Decree was terminated in November 2013 following the completion by Plains of its obligations thereunder.

EXHIBIT A ¹

To Letter Dated June 19, 2015



PHMSA Reported Incidents 2006 to 1Q 2015

	2006	2007	2008	2009	2010	2011	2012	2013	2014	Q1 15	Total	Percent
PIPELINE Incidents												
Releases Under 1 Barrel	1	3	4	1	2	-	1	-	1	-	13	15%
Releases 1-5 Barrels	7	6	1	5	3	1	2	-	2	-	27	32%
Releases 5-20 Barrels	2	4	-	4	-	-	2	1	-	-	13	15%
Releases > than 20 Bbls	9	3	2	2	2	5	3	3	2	1	32	38%
Total	19	16	7	12	7	6	8	4	5	1	85	100%
FACILITY Incidents												
Releases Under 1 Barrel	-	3	4	1	1	2	3	4	5	1	24	17%
Releases 1-5 Barrels	3	2	3	7	3	5	12	6	12	3	56	39%
Releases 5-20 Barrels	3	1	1	3	3	1	7	6	5	2	32	22%
Releases > than 20 Bbls	5	4	2	3	4	1	3	1	8	1	32	22%
Total	11	10	10	14	11	9	25	17	30	7	144	100%
TOTAL Incidents												
Releases Under 1 Barrel	1	6	8	2	3	2	4	4	6	1	37	16%
Releases 1-5 Barrels	10	8	4	12	6	6	14	6	14	3	83	36%
Releases 5-20 Barrels	5	5	1	7	3	1	9	7	5	2	45	20%
Releases > than 20 Bbls	14	7	4	5	6	6	6	4	10	2	64	28%
Total	30	26	17	26	18	15	33	21	35	8	229	100%

Observations

- Pipeline releases declining steadily in total & > 5bbls
- Facility releases fluctuating, but significant % of total releases occurred within the fence line with limited impact on third party lands

--->5 bbls

--->5 bbls

(1) The table of reported incidents above includes the 175 incidents for Plains Pipeline for the 9-10 year period included in the PHMSA website as included in the media reports referenced in the June 5, 2015 letter. To ensure a complete and comparable analysis, the table also includes an additional 54 incidents reported by entities controlled by Plains All American that operate assets engaged in crude oil and refined products activities regulated by PHMSA. The table excludes activities for periods prior to Plains' ownership of such entities.

EXHIBIT B

To Letter Dated June 19, 2015 Integrity Management Summary

Plains All American (“PAA”) has implemented several programs and initiatives that in many instances go above and beyond regulatory requirements to ensure the integrity and safety of PAA’s pipeline assets. Set forth below is a brief summary of such integrity management programs and initiatives.

In-line Inspection (ILI) Assessments - PAA has assessed virtually all of its PHMSA regulated pipeline miles with ILI tools to test for internal and external corrosion and dents. The regulations require that this be performed only in High Consequence Areas (HCAs). PAA has also run ILI tools in the majority of its non-PHMSA regulated pipeline miles and continues to expand that initiative. In addition, PAA runs ILI crack tools in pipelines that may be susceptible to different types of cracking mechanisms.

Note that Line 901 does not exhibit characteristics of cracking susceptibility and that Line 901 had ILI tool runs in 1996, 2007, 2012 and 2015.

Close Interval Survey (CIS) Assessments – PAA has assessed virtually all of its pipelines (including lines that are not required to be tested) with CIS assessments, which confirm that a pipeline’s coating and cathodic protection system is properly functioning. This type of assessment requires a person to walk the entire length of the pipeline. Line 901 had CIS assessments in 2008 and 2015.

GIS Mapping and Data Integration– PAA uses a geographic information system (“GIS”) to create and maintain maps for all of PAA’s active and retired pipelines. Only PHMSA regulated pipelines are required to be mapped in a GIS system. Using the Pipeline Open Data Standard, PAA has developed a data integration capability that allows creation of aerial maps that contain all the key attributes of a pipeline system. By integrating pipeline construction, operation, maintenance, and integrity with high quality aerial photos, we are able identify threats to the integrity of a pipeline that may not be identified with the results of just one integrity assessment.

Water Crossing Assessments - PAA uses third-party experts to assess water flow and scouring potential at water crossings in high flow-rate rivers, particularly in the Rocky Mountain region and in Canada. Based on the output of this analysis PAA will, where necessary, use directional drilling technology to install new water crossings and increase the depth of cover (the distance between the bottom of a river bed and the buried pipe) for such pipelines segments. There are no regulatory requirements to perform such water crossing assessments or to provide additional depth of cover for such pipeline segments. As a part of this initiative, the water crossings for Line 901 at both Refugio Creek and the Santa Ynez River have been recently evaluated by a third party expert; there were no issues for the Refugio Creek crossing and analysis for the Santa Ynez River crossing is not yet complete.

Valve Replacements – PAA is required to determine if remotely controlled valves or check valves (known as emergency flow restriction devices or “EFRDs”) are needed to protect HCAs.

While such requirement only applies to HCAs, PAA has a continual evaluation process to determine the need to replace existing manual valves with EFRDs or install new EFRDs in strategic locations. All valves on Line 901 are EFRDs.

Risk Screening Program (“RSP”) – PAA employees perform a risk screening process to assess the potential threats associated with its non-PHMSA regulated assets and develops risk mitigation plans to address such threats. As a result of this process, PAA has taken over 6,200 miles of pipeline out of service over the last ten years. Also, a component of this program is to determine the frequency with which ILI tools will be run on each non-PHMSA regulated pipeline. There is no requirement to have an RSP type program for pipelines that are not subject to PHMSA regulations.

New Pipeline Programs – PAA has also adopted a number of practices that are above and beyond regulatory requirements for new pipelines we construct. These practices include:

- Running an ILI tool in new mainlines shortly after they are placed in service in order to establish a baseline assessment;
- Conducting a direct current voltage gradient test on new mainlines to ensure that the coating was not damaged during the installation of the pipeline;
- Testing 100% of the welds; and
- Evaluating the use of EFRDs, whether the new pipeline is located in an HCA or not.

Industry Participation – PAA actively participates in a number of industry efforts to improve the safety and integrity of hazardous liquids pipelines. Set forth below are some of the higher profile efforts in which PAA employees actively participate:

- A PAA employee is the current chairman of the Pipeline Integrity Work Group for API/AOPL;
- A PAA employee is leading the industry work group focused on developing a recommended practice to identify cracks in pipelines;
- A PAA employee lead the industry work group that developed a Data Integration Matrix used to enhance the evaluation of the integrity of pipelines;
- A PAA employee is on the Pipeline Research Council International board; and
- PAA employees participate in a number of other industry work groups and initiatives to improve pipeline safety.

EXHIBIT C

To Letter Dated June 19, 2015

PAA Consolidated Integrity & Maintenance Expenditures (in \$000s)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Total
I&M by Expenditure Type											
Integrity Expenditures:											
U.S. Assets	\$ 4,401	\$ 12,770	\$ 36,921	\$ 69,635	\$ 47,565	\$ 58,877	\$ 56,041	\$ 76,616	\$ 94,359	\$ 151,351	\$ 608,536
Canadian Assets	3,342	4,388	6,991	7,454	19,592	20,237	33,359	75,033	83,782	47,549	301,729
Total Integrity Expenditures	\$ 7,743	\$ 17,158	\$ 43,912	\$ 77,089	\$ 67,157	\$ 79,113	\$ 89,401	\$ 151,649	\$ 178,141	\$ 198,900	\$ 910,264
Maintenance Expenditures:											
U.S. Assets	\$ 33,218	\$ 46,515	\$ 77,147	\$ 82,227	\$ 98,304	\$ 98,164	\$ 124,694	\$ 146,961	\$ 170,233	\$ 171,059	\$ 1,048,523
Canadian Assets	11,077	14,171	17,940	27,100	16,361	24,349	47,198	99,225	98,522	110,437	466,379
Total Maintenance Expenditures	\$ 44,295	\$ 60,686	\$ 95,087	\$ 109,327	\$ 114,665	\$ 122,513	\$ 171,892	\$ 246,186	\$ 268,755	\$ 281,496	\$ 1,514,902
Integrity & Maintenance Expenditures:											
U.S. Assets	\$ 37,619	\$ 59,285	\$ 114,069	\$ 151,862	\$ 145,869	\$ 157,041	\$ 180,735	\$ 223,577	\$ 264,592	\$ 322,410	\$ 1,657,059
Canadian Assets	14,419	18,559	24,931	34,555	35,954	44,586	80,557	174,258	182,304	157,986	768,108
Total Integrity & Maintenance Expenditures	\$ 52,038	\$ 77,844	\$ 139,000	\$ 186,417	\$ 181,822	\$ 201,626	\$ 261,292	\$ 397,835	\$ 446,896	\$ 480,396	\$ 2,425,166