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SABLE OFFSHORE CORP. and PACIFIC PIPELINE COMPANY

SUPERIOR COURT OF THE STATE OF CALIFORNIA
COUNTY OF SANTA BARBARA

CENTER FOR BIOLOGICAL DIVERSITY, et al.,
Petitioners and Plaintiffs,
v.
CALIFORNIA DEPARTMENT OF FORESTRY
AND FIRE PROTECTION, et al.,
Respondents and Defendants,
and
SABLE OFFSHORE CORP., et al.,
Real Parties in Interest.

Case No. 25CV02244
[Coordinated with Case No. 25CV02247]
Assigned for all purposes to:
Hon. Donna D. Geck
DECLARATION OF MICHAEL J. ROSENFELD IN SUPPORT OF REAL PARTIES IN INTEREST SABLE OFFSHORE CORP. AND PACIFIC PIPELINE COMPANY'S OPPOSITION TO APPLICATION FOR PRELIMINARY INJUNCTION (VOL. 1 OF 4)
[Filed concurrently with Opposition to Application for Preliminary Injunction; Declarations of Michael A. Mische, Bart Leininger, Brien Vierra, and Steve Rusch]
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1 **DECLARATION OF MICHAEL J. ROSENFELD**

2 I, Michael J. Rosenfeld, declare as follows:

3 1. My name is Michael J. Rosenfeld and I am a mechanical engineer. I have been engaged
4 by Alston & Bird LLP, counsel to Sable Offshore Corp. (Sable) and Pacific Pipeline Company,¹ to provide
5 my expert opinions as to the Declaration of Richard Kuprewicz submitted to the Superior Court of the
6 State of California, County of Santa Barbara, in the matter of Case Nos. 25CV02244 and 25CV02247.
7 Below, I provide my qualifications to provide these expert opinions. I have personal knowledge of the
8 matters set forth in this Declaration, and if called as a witness, I could and would testify competently
9 thereto.

10 **I. Introduction**

11 2. The purpose of this report is to critically review and interpret the Declaration of Richard
12 Kuprewicz submitted to the Superior Court of the State of California, County of Santa Barbara, in the
13 matter of Case Nos. 25CV02244 and 25CV02247. These cases concern the return to service of Lines 324
14 and 325A/B of the Las Flores Pipeline System, operated by Sable Offshore (Sable) and Pacific Pipeline
15 Company (PPC). I was asked to perform this review and prepare this report by Alston & Bird, LLP on
16 behalf of Sable and PPC.

17 3. I am qualified to give my professional opinion in this matter by education and experience.
18 My current position is Chief Engineer at RSI Pipeline Solutions, LLC, a pipeline engineering consulting
19 firm. I am a mechanical engineer by training receiving a Bachelor of Science in Engineering from the
20 University of Michigan in 1979, and Master of Science in Engineering from Carnegie-Mellon University
21 in 1981. I have been involved with petroleum and natural gas pipelines since the late 1980s. My
22 experience includes performing numerous metallurgical failure analyses having direct causes including
23 but not limited to pipe seam defects, girth weld defects, corrosion of various types, stress-corrosion
24 cracking, hydrogen assisted cracking, fatigue cracking due to the effects of cyclic pressure or vibration,
25 and excessive loading due to geohazards. I have also performed numerous root cause failure investigations
26

27 ¹ Pacific Pipeline Company (PPC) is a wholly owned subsidiary of Sable Offshore Corp. For the purpose of this
28 declaration, references to Sable or PPC as owner/operator of the pipeline system have the same meaning and may be used
interchangeably.

1 in which various management gaps such as inadequate specifications or procedural errors were causal.
2 My experience also includes analysis of pipeline stresses, evaluation of pipeline fitness for service,
3 analysis of in-line inspection (ILI) data, development of technical procedures and integrity management
4 plans, regulatory compliance, and training in codes and standards. I have also been principal investigator
5 in several research projects funded by pipeline interest groups including PHMSA, ASME, API, and GRI.
6 I also have held executive positions in pipeline safety standards development committees. A true and
7 correct copy of my curriculum vitae is attached hereto as **Exhibit A**.

8 **II. Conclusions**

9 4. As will be demonstrated in the sections that follow, Mr. Kuprewicz fails to take into
10 account:

- 11 a) Known facts about the 2015 Line 901 incident;
- 12 b) Known contributing factors and deficiencies related to the operation and integrity
13 management of the former Line 901 under the previous owner and operator of the
14 facility;
- 15 c) Requirements of the Corrective Action Order (CAO) and Consent Decree (CD)
16 issued by the Pipeline and Hazardous Materials Safety Administration and
17 additional requirements imposed by the Office of the State Fire Marshall (OSFM)
18 that correct the operational and integrity management deficiencies that were causal
19 or contributed to the 2015 incident; and
- 20 d) Other known facts that are contrary to the positions stated in Mr. Kuprewicz's
21 opinions.

22 5. By not accounting for these important facts Mr. Kuprewicz has set forth positions that are
23 unfounded. To the extent that opinions were made without relevant information, they are uninformed and
24 speculative. To the extent that relevant facts were knowable from information available to anyone in the
25 public domain but were not considered or accounted for, his opinions were not based on evaluation
26 performed to a reasonable standard of engineering practice. To the extent that such facts were known by
27 him and deliberately omitted, or positions were stated to the contrary, Mr. Kuprewicz's opinions are biased
28 or deceptive.

1 6. Mr. Kuprewicz concludes in Paragraph 11 of his Declaration that the Las Flores Pipeline
2 System is not safe to operate even if it meets the OSFM state waivers. He also states in Section X of his
3 Exhibit B that the Las Flores Pipeline System is unusually dangerous due to its age and design flaws.
4 These are pejorative statements built on an aggregation of claims made without supporting data, and which
5 should be disregarded as nonfactual and noncredible. He has provided no data, scientific or engineering
6 analysis, or factual evidence that supports these opinions.

7 **III. Review and Interpretation of the Kuprewicz Declaration**

8 **A. Declaration Review Process**

9 7. This review steps through the Declaration prepared by Mr. Richard Kuprewicz and
10 supporting Appendices point by point. His positions are interpreted and critically evaluated to assess
11 whether they are based on fact and science.

12 8. Documents that I have reviewed and relied on in addition to Mr. Kuprewicz's Declaration
13 are listed in the references attached hereto (See Section IV Below).

14 **B. Mr. Kuprewicz's Technical Issues and Opinions**

15 **1. Kuprewicz Technical Issues in Paragraph 8**

16 9. Mr. Kuprewicz identified five technical issues with the proposed restart of the San Flores
17 Pipelines in Paragraph 8 of his Declaration. They are repeated here verbatim:

- 18 a. The design of the Pipelines renders the federal mandated cathodic protection system,
19 intended to help address pipeline external corrosion, ineffective.
- 20 b. Current inline inspection (ILI) technologies cannot adequately assess all forms of external
21 corrosion threats that most likely exist on the Pipelines.
- 22 c. The high operating temperatures needed to reduce the viscosity of the heavy crude oil
23 significantly accelerate all forms of external pipeline corrosion that will not be mitigated
24 by the ineffective cathodic protection system once the Pipelines go into operation.
- 25 d. Segments at risk of corrosion related cracking (i.e., stress corrosion cracking or selective
26 seam corrosion cracking) are at the highest risk of failure.
- 27 e. The poorly designed Pipelines cannot be made as safe as new pipelines.

1 magnetic corrosion product. A second ILI technology to be used is the transverse-field MFL (also called
2 circumferential MFL or MFL-C), specifically designed and configured to detect selective seam weld
3 corrosion (SSWC) in the ERW seams (although, as will be discussed later, there is a low probability of
4 SSWC in Line 324), as well as narrow axial external corrosion if it is present in Line 325A/B. A third ILI
5 technology is UT crack detection, which is capable of detecting stress-corrosion cracking (SCC) colonies,
6 although as will be discussed later there is a low probability of SCC being present. Industry experience
7 has been that multiple tool technologies significantly increases the probability of detection of many
8 conditions of interest in the pipeline. [Ref: Thompson, et al; Harris]

9 12. Corrosion management is about more than ILI detection, since detection capabilities are
10 generally good even when an ILI tool is performing sub-optimally. Three other important enhancements
11 specified by the OSFM state waiver, that Mr. Kuprewicz fails to account for in an apparent attempt to bias
12 the reader of his statement, are the frequency of ILI inspections, the required ILI field validation, and run-
13 to-run comparisons to identify changes and rates of change in the condition of the pipeline. Notably, Sable
14 will be required to run each ILI tool type *twice per year in the first two years and annually thereafter*.
15 This is far more often than almost any other pipeline in the US. *The current regulations call for ILI*
16 *surveillance to take place once every five years*. The frequent ILI will give Sable multiple opportunities
17 to assess the tool performance, work with the ILI vendor to regrade the results based on field findings,
18 and multiple chances to understand the condition of the pipeline before serious corrosion can occur. The
19 previous operator's practices in these areas were not anywhere nearly as robust.

20 **c. Technical issue (c)**

21 13. Mr. Kuprewicz is concerned about the elevated operating temperature of the pipeline
22 causing high corrosion rates. This is a well-known phenomenon. Mr. Kuprewicz has not considered the
23 frequent ILI and corrosion growth rate assessments required by the OSFM state waiver will make it
24 possible to become aware of corrosion rates and corrosion growth often enough to respond with repairs
25 on a timely basis.

26 **d. Technical issue (d)**

27 14. Mr. Kuprewicz states that segments at risk of environmental cracking are at the highest
28 risk of failure. He is referring to SCC and apparently SSWC. As will be discussed later, these are the

1 least likely forms of degradation to affect the pipelines. The 2015 failure was not due to environmental
2 cracking, no environmental cracks were observed in the investigation of that failure, and ILI tools capable
3 of detecting these conditions will be used on a much more aggressive schedule in the future by Sable. Mr.
4 Kuprewicz is opining about occurrences of environmental cracking that are not and have never been
5 identified or found by any inspection or report, as reflected in the publicly available materials relative to
6 the 2015 failure. This is an effort to fabricate facts concerning the integrity of the Pipeline which Mr.
7 Kuprewicz knows are baseless.

8 **e. Technical issue (e)**

9 15. Mr. Kuprewicz asserts that the pipelines cannot be made as safe as a new pipeline. He
10 provides no technical information to back this statement. The pipelines have been pressure tested to prove
11 strength and frequently inspected using various technologies to monitor their condition. All new pipelines
12 become old pipelines, the question is how those pipelines are monitored and maintained. Here the
13 monitoring and maintenance program required by the regulators and the Consent Decree are state of the
14 art. Again Mr. Kuprewicz's statement with respect to the need for a new pipeline is without any
15 foundation or justification.

16 **2. Kuprewicz Opinions in Paragraph 10**

17 16. Mr. Kuprewicz expressed five opinions in Paragraph 10 of his Declaration. They are
18 repeated verbatim as follows:

- 19 a) The reliance on ILI technology to identify corrosion threats before failure is
20 misplaced because such tools can miss a lot of cracks. There are multiple forms of
21 corrosion on the Pipelines, and ILI is insufficient to detect some of them.
- 22 b) The proposed hydrotests are also insufficient to address certain types of corrosion
23 or predict corrosion growth. For example, Maximum Operating Pressure ("MOP")
24 hydrotests are not adequate to test for crack forming potential on the Pipelines.
- 25 c) The State Waivers do not assure adequate spike hydrotesting, which is a method to
26 address various forms of crack forming potential. The values for the spike test on
27 Line 324 are too low for corrosion cracking screening and evaluation. Hydrotesting
28 for Lines 325 A and B must be conducted in segments given the elevation changes.

1 It is unclear, however, whether the testing parameters are adequate for Line 325A
2 due to missing information. In addition, the Waivers do not appear to require any
3 hydrotesting for Line 325B.

4 d) A key corrosion performance tracking process set in the State Waivers for the
5 Pipelines is missing. This information, which helps identify possible corrosion “hot
6 spots,” is especially important given the history of extensive corrosion on the
7 Pipelines.

8 e) The State Waivers will not provide an equal or greater level of safety as if the
9 Pipelines were equipped with an effective cathodic protection system to avoid
10 pipeline failure due to external corrosion. The current design of the Pipeline renders
11 the cathodic protection system ineffective. External corrosion on the Pipelines is
12 exacerbated by operation of the Pipelines at elevated temperatures, which seriously
13 increases the corrosion rate.

14 **a. Opinion (a)**

15 17. There are multiple components of this opinion to examine. The first is that Mr. Kuprewicz
16 states a logical inconsistency: that “because ILI tools can miss a lot of cracks”, reliance on ILI to find
17 corrosion is misplaced. This is illogical because crack detection tools and corrosion detection tools are
18 not the same tools and use different technologies. Corrosion tools indeed will “miss a lot of cracks”
19 because they are not designed to detect cracks – ultrasonic crack detection tools specified for use by the
20 OSFM in the state waiver are the appropriate tools for crack detection. ILI tools targeting corrosion on the
21 other hand, specifically the magnetic and ultrasonic metal loss tools specified in the state waiver, are
22 designed to detect corrosion and are effective for that purpose. Informed pipeline operators understand
23 these differences and select the tool type(s) appropriate for the condition(s) they must manage. The OSFM
24 state waiver specifies that magnetic and ultrasonic metal loss tools, and ultrasonic crack detection, tools
25 be used. Neither of the ultrasonic technologies were used by the prior operator. The state waiver
26 introduces significant additional diversity to the inspection capabilities. Industry experience has been that
27 using multiple tool technologies and integrating the ILI data significantly improves the probability of
28 detecting, characterizing, and sizing features of interest in the pipeline.

1 18. The second is Mr. Kuprewicz states that multiple forms of corrosion are present on the
2 pipeline(s) but does not describe the different forms of corrosion he claims are present. The Line 901
3 failure analysis [Ref: DNV-GL, Appendix M to PHMSA FIR] and PHMSA’s incident investigation [Ref:
4 PHMSA FIR] did not identify different forms of corrosion contributing to the failure, nor differing forms
5 of corrosion being present on other parts of the pipeline. Mr. Kuprewicz has not reviewed the results of
6 field digs to investigate corrosion analysis already performed by Sable, in response to ILI, to determine
7 what different types of corrosion are present. His statement is entirely speculative without reviewing any
8 factual data.

9 19. The third point is that Mr. Kuprewicz states that ILI is inadequate to detect some forms of
10 corrosion though he does not state what those undetectable forms of corrosion are. All ILI tools have
11 lower thresholds of detectable flaw size; detection and sizing performance differ with the size and
12 orientation of the flaws. Taken together, the different tool technologies to be used by Sable are capable
13 of detecting various forms of corrosion if they are present and of detectable size, including pitting
14 corrosion, general corrosion, corrosion along or adjacent to seams, narrow axially aligned corrosion, and
15 other forms of corrosion. Furthermore, tool performance improves with large pipe such as Lines 324 and
16 325 because more sensors and supporting components can be fitted in the larger circumference, and
17 defects of concern are proportionally larger and easier to detect, compared with small pipe sizes. [Ref:
18 Nestleroth & Rosenfeld]

19 **b. Opinion (b)**

20 20. Mr. Kuprewicz states that the hydrotests are insufficient to address certain types of
21 corrosion but does not state which types of corrosion are at issue. To identify all potential corrosion leaks,
22 Sable has been required by the OSFM state waiver to significantly enhance its computational leak
23 detection technology, an area in which the prior operator was grossly deficient. The frequency of
24 inspections specified by the OSFM state waiver will give multiple opportunities to identify such features
25 versus the prior operator.

26 21. Mr. Kuprewicz also states that the MOP hydrotests are not adequate to test for crack
27 forming potential. He seems confused about the purpose of the hydrostatic pressure tests, which is to
28 demonstrate that no defects, whether corrosion, cracks (of any type), or other degradation is present and

1 having a severity significant enough to threaten the safe operation *at the time of the test*, which holds the
2 pressure at 1.5 X MOP for a period of fifteen minutes, followed by an eight hour test at 1.25 X MOP. In
3 other words, the purpose is to demonstrate the current condition of the pipeline is safe with a known factor
4 of safety. Mr. Kuprewicz does not demonstrate by any rational engineering analysis why the pressure tests
5 performed are inadequate for a plausible postulated crack growth scenario.

6 **c. Opinion (c)**

7 22. Mr. Kuprewicz makes several statements in his Opinion (c) that merit examination. Firstly,
8 he states that the State Waivers do not assure adequate spike hydrotesting (in Line 324), which he describes
9 as “a method to address various forms of crack forming potential”. Mr. Kuprewicz seems confused about
10 the purpose of the spike hydrostatic test. It is a technique for mitigating stress corrosion cracking (SCC)
11 or manufacturing defects in certain older vintage seam types having low ductility, where effective ILI for
12 cracks is unavailable (which was the case in 1979 when the spike test concept was first proposed). [Ref:
13 Baker Engineering & Kiefner & Assoc., TTO-6; Rosenfeld]. The test concept presumes that unknown
14 cracks are present and recognizes that holding a crack at the near-failure point could cause damage during
15 the test leading to failure even if the crack is not a threat at the operating pressure. The spike test is
16 conducted by taking the pipeline to a very high pressure for a short period of time (just a few minutes is
17 sufficient) to force any significant cracks to fail while minimizing subcritical crack growth in those that
18 do not fail, then lowering pressure to no more than 90% of the high level to avoid further damage to
19 surviving cracks and holding at the reduced pressure to confirm a lack of leaks. The test has nothing to
20 do with the potential to form cracks – if conditions are favorable to cracks forming, they could form just
21 as easily after the hydrotest is completed. Since crack detection ILI has been and will be performed, a
22 spike test is really unnecessary. The ILI will be more sensitive than the pressure test. However, OSFM
23 has made the spike test a condition of its state waiver for Line 324 out of an abundance of caution as the
24 responsible regulatory authority, which is their public duty and prerogative.

25 23. Related to the above point, Mr. Kuprewicz states that the spike hydrostatic test is too low
26 for “corrosion cracking screening and evaluation”. Presumably by “corrosion cracking”, which is not an
27 industry-standard term, he is referring to stress-corrosion cracking (SCC). Even though SCC cracking
28 was not identified in the course of the Line 901 failure investigation, consistent with the PHMSA Advisory

1 Bulletin the OSFM has required an ultrasonic crack detection ILI and transverse field magnetic ILI, which
2 together or individually can indicate the presence of SCC large enough to pose a future threat. The spike
3 hydrostatic test to 1.5X MOP is adequate to prove the current integrity of the pipeline with a factor of
4 safety of 1.5, and demonstrate that significant SCC that is a current threat at the MOP is not present. If
5 less significant SCC is present, it will not be revealed by the test, though it can be expected to be revealed
6 by the crack detection ILI.

7 24. Mr. Kuprewicz notes that due to elevation changes along the route, the pipeline must be
8 pressure tested in multiple test segments. Had Mr. Kuprewicz reviewed the hydrotest plans he would have
9 noted that the hydrotest of the pipelines was broken up into eight different segments to conform to the
10 elevation changes associated with the pipeline. This is a common aspect for any and all pipelines installed
11 in anything but flat terrain and must be accounted for in the test plan. It can increase testing cost, but it is
12 not unique to the Las Flores Valley Pipeline System, pipeline engineers understand how to test in hilly
13 terrain, and it is not a reason to object to the testing.

14 25. He also states that it is unclear whether the testing is adequate for Line 325A due to his
15 lack of data. In that case, Mr. Kuprewicz is speculating and has no basis in fact for objecting.

16 **d. Opinion (d)**

17 26. Mr. Kuprewicz states that a key corrosion tracking process is missing from OSFM's state
18 waiver for identifying corrosion "hot spots". He does not describe the corrosion tracking process that is
19 missing, nor does he define "hot spot" though presumably he means it as a localized area of corrosion
20 having a growth rate that is greater by a vague, undefined amount than is typical of other parts of the
21 pipeline. The OSFM state waiver requires aggressive ILI run frequencies and dig response criteria in
22 order to produce a robust corrosion tracking process. ILI for corrosion must be performed twice annually
23 the first 2 years and annually thereafter, which is far more frequently than every 5 years practiced with
24 most pipelines. ILI for cracks must be performed annually, which is also far more frequent than the 5 year
25 interval practiced with most other pipelines. Metal loss of 40% of the wall thickness or more, accounting
26 for tool performance, must be investigated within 6 months. This is also unusually stringent and accounts
27 for potential growth during the interval between running ILI and responding in the field. OSFM also
28 requires a procedure for estimating corrosion growth rates from comparisons of multiple ILI runs and for

1 making projections for when each corrosion feature will attain a depth of concern. As the regulatory
2 authority, the OSFM will have the right to review all such information at any time and perform its own
3 analysis. OSFM’s conditions appear to be designed to make it highly unlikely that a corrosion “hot spot”
4 will go unnoticed for long.

5 **e. Opinion (e)**

6 27. Mr. Kuprewicz objects that the OSFM state waiver will not provide the same level of safety
7 as a pipeline with effective cathodic protection (CP), due to the characteristics of the coating system. The
8 OSFM has taken this into consideration — performing ILI frequently enough to indicate and size corrosion
9 is an important alternative risk mitigation and barrier against corrosion failure where CP will be
10 ineffective. Mr. Kuprewicz provides no risk assessment showing that frequent ILI cannot offset risk due
11 to ineffective CP.

12 28. Moreover, Mr. Kuprewicz provides no risk analysis accounting for the numerous
13 improvements and upgrades to the facility and operating practices that demonstrates that the pipeline will
14 be inadequately safe. The OSFM, as a regulatory agency having responsibility in risk-critical subject
15 areas, understands risk analysis and applies risk models to its decisions. Moreover, OSFM has performed
16 extensive fact-based analysis of the pipelines at issue and has personally inspected the repairs and
17 upgrades to the pipelines in conformance with the state waivers.

18 29. Mr. Kuprewicz also objects that due to the elevated operating temperatures, corrosion rates
19 will be “seriously increased”. This was observed to be the case with the former Line 901 failure. It is an
20 understood phenomenon and is not unique to the Las Flores Pipeline system. Other heated oil pipelines
21 are operated in the US. The OSFM requires measures be in place to ensure the pipelines are operated
22 safely under these conditions. The fact that the previous operator applied inadequate methods to estimate
23 corrosion rates does not mean that it cannot be done. In fact, pipeline operators do this often, and the
24 OSFM state waiver requires a process to do that, accounting for tool performance and measurement
25 uncertainty.

26 **C. Positions Stated in Kuprewicz’s Declaration Exhibit B**

27 30. Mr. Kuprewicz supplements his five technical concerns in Paragraph 8 and five main
28 opinions in Paragraph 10 with additional statements in his Declaration and Exhibits B and C. These will

1 also be critically examined. The following discussion refers to Sections V through X from his Exhibit B
2 “Evaluation of Las Flores Pipeline System Startup Proposal”, Dec. 20, 2024.

3 **1. Section V. TIMP Regulations Are Not Working**

4 **a. Inadequacy of TIMP Regulations**

5 31. Mr. Kuprewicz states that transmission integrity management planning (TIMP) regulations
6 are not working to protect the public. This is demonstrably false. PHMSA’s own data available to anyone
7 with an internet connection [Ref: www.phmsa.dot.gov] shows that TIMP along with improved technology
8 and operator focus is gradually reducing the running average incident metrics for hazardous liquid
9 pipelines over the past 20 years:

Reference period	Avg. Annual Incident Count	Avg. Annual Barrels Spilled	Avg. Annual Barrels Lost
3-yr Avg (2022-2024)	294	63,300	32,618
5-yr Avg (2020-2024)	312	81,959	48,946
10-yr Avg (2015-2024)	364	85,502	51,394
20-yr Avg (2005-2024)	367	89,261	51,450

15 32. It should be noted that approximately 80% of the reported incidents occurred within
16 facilities such as pump stations, terminals, and tankage farms, rather than on the pipeline right-of-way,
17 with valves and equipment being the largest component. Those causes are not managed by a TIMP
18 program. Essentially, Mr. Kuprewicz’s complaint is with PHMSA, not Sable, and his complaint is
19 understood as TIMP not reducing incidents enough to suit him personally. Mr. Kuprewicz also seems to
20 be confusing regulatory compliance with actual safety, a common thought bias.

21 33. Mr. Kuprewicz states “pipeline integrity management tools are not a substitute for proper
22 pipeline design or effective cathodic protections. Their purpose is simply to monitor the condition of
23 pipelines over time and identify threats to the pipeline’s integrity.” This statement is biased and
24 misleading in that it gives a very incomplete picture of the TIMP process. TIMP is a structured approach
25 to managing pipeline risk, consisting broadly of the following steps: 1) analyze and integrate data about
26 the pipeline including design and operating history; 2) identify integrity threats; 3) perform risk
27 assessment to determine consequences of failure and identify high risk locations; 4) perform an assessment
28 of the condition of the pipeline (this is the only TIMP process step Mr. Kuprewicz acknowledges) with

1 respect to the integrity threats, prioritized by risk in accordance with the risk assessment; 4) respond to
2 the condition assessment results with repairs prioritized by severity and location-based risk; 5) develop
3 preventive and mitigative measures consisting of facility and procedural improvements to avoid or prevent
4 occurrence of threats throughout the system; and 6) evaluate performance against the plan commitments,
5 verify that risk is reduced, and identify process improvements. [Ref: API RP 1160] The process is
6 continually repeated. TIMP is a complex process; not all elements work perfectly and not all operators
7 perform equivalently, but that does not mean the process is unable to lower risk.

8 **b. Hydrostatic Testing Assessments**

9 34. Mr. Kuprewicz states “For a pipeline experiencing certain cracking threats such as selective
10 seam cracking (SSC) or stress corrosion cracking (SCC)—corrosion threats *that likely exist* (emphasis
11 added) along the Las Flores Pipeline System—a subpart E hydrotest is inadequate.” This statement is
12 incorrect on several levels.

13 35. To state that something could exist, or even is likely to exist, does not mean that it has
14 existed, does now exist, or will exist. As will be discussed below, Mr. Kuprewicz fails to account for
15 known factual information to support his assertion that certain conditions are likely. In my opinion, they
16 are unlikely.

17 36. Firstly, “selective seam cracking (SSC)” is not a generally recognized condition. Based on
18 my subject matter knowledge, I believe that Mr. Kuprewicz is referring to “selective seam weld corrosion”
19 (SSWC), a condition that can affect older varieties of pipe manufactured with electric resistance welded
20 (ERW) seams or flash welded (FW) seams. Line 324 is modern ERW seam pipe. Extensive testing and
21 research over the years has concluded that susceptibility to SSWC is influenced by composition of the
22 pipe steel and other factors associated with pipe manufactured prior to 1985, the two most significant
23 influences being carbon content greater than 0.10% and sulfur content greater than 0.007%. According
24 to the metallurgical failure analysis of the Line 901 failure [Ref: DNV-GL] published with PHMSA’s
25 public failure investigation report, the composition of the steel in the failure pipe and upstream and
26 downstream pipes exhibited carbon content of 0.078-0.083% and sulfur content of 0.007%. [Ref:
27 McMahon, et al] The subject pipe was manufactured in 1986. Thus susceptibility to SSWC should be
28 very low, and in fact no SSWC was observe in the Line 901 failure investigation. In the *unlikely* event

1 that SSWC was to occur, the transverse field magnetic ILI tool used by Sable, as required by the OSFM
2 state waiver, was developed to detect SSWC.

3 37. Secondly, Mr. Kuprewicz considers SCC to be *likely*. SCC requires specific stress and
4 environmental condition. SCC in pipelines has two forms: near-neutral-pH (NNpH) or high-pH (HPH),
5 with differing necessary environments. [Ref: NEB Inquiry] NNpH SCC requires shielding from CP and
6 anaerobic conditions. Although the CP-shielding conditions exist, evidently conditions were only
7 intermittently anaerobic or favorable to NNpH SCC, resulting instead in pitting metal loss. Applied stress
8 is also a promoting factor. While there is no theoretical lower stress at which SCC cannot occur, it is
9 rarely observed at applied stresses below 50% Specified Minimum Yield Strength (“SMYS”) absent other
10 sources of stress such as external forces or residual stress. At the pipeline MOP of 1,003 psig, the hoop
11 stress is 54% of SMYS. However, normal operating pressure is in the range of 250 to 600 psig, resulting
12 in prevalent stress levels of 15-33% SMYS. At such stress levels, the driving force for SCC is weak,
13 cracking colonies will be sparse, crack growth rates will be low, and the condition is more likely to go
14 dormant or be overtaken by pitting during intermittent periods that are environmentally not conducive to
15 SCC. Thus NNpH severe enough to threaten the pipeline is *unlikely*. HpH SCC has differing
16 environmental conditions from the NNpH type. While temperatures above 100 deg F are favorable to
17 HpH SCC, the condition only develops within a narrow range of cathodic potentials indicative of partially
18 impaired but not shielded CP. Thus HpH SCC is also *unlikely*. The ultrasonic crack detection ILI tools
19 specified by the OSFM state waiver are designed to detect SCC if it is present in a detectable size.

20 38. Thirdly, Mr. Kuprewicz states that a 49 CFR Part 195, Subpart E test to a test pressure ratio
21 of 1.25 is “inadequate” in connection with his postulated SSWC or SCC. Any pressure test above
22 1.1xMOP (the maximum allowed surge condition) demonstrates the present safety of the pipeline. No
23 test pressure proves an absence of flaws no matter how high the test pressure. The higher the test pressure,
24 the smaller will be any undiscovered flaws that survive the test. All things being equal, larger flaws, if
25 they can enlarge in service, grow to failure in less time than smaller flaws, so higher tests are more
26 effective for demonstrating some positive factor of safety >1.0 for a longer period of time. But certainly
27 if significant SSWC or SCC did exist of a size that could be caused to fail at a TPR of 1.25, the Subpart
28 E test is adequate, and certainly the spike test required by OSFM is adequate. Later in the same paragraph

1 he states that it is not clear whether hydrotesting, if performed with be a Subpart E test or a different test
2 to a higher pressure level. Clearly then he lacks necessary information to form an opinion and is
3 speculating.

4 39. Mr. Kuprewicz states that “Current ILI technology cannot reliably identify if such cracking
5 threats are present.” This is patently false, biased, and misleading. In fact, ILI is more effective than
6 hydrostatic testing, a point which Mr. Kuprewicz acknowledges in the very next section of this Exhibit.
7 The industry has for the past 25 or more years relied on ILI to detect and characterize threats such as
8 SSWC and SCC, as well as other types of cracks such as seam fatigue cracks and pipe manufacturing
9 defects in seams.[Ref: Krieg, et al] Although no inspection process is perfect, ILI has proven over and
10 over to be an effective integrity management tool. Frequent ILI intervals with robust validation, and use
11 of multiple tool technologies, will reduce the chances of completely missing something important.

12 **c. ILI Assessments**

13 40. In this section, Mr. Kuprewicz makes numerous negative statements about ILI:

- 14 • Some ILI tools are more suitable than others depending on the threat. ... Operators
15 don’t always select the ILI technology best suited to help identify threats on their
16 system.
- 17 • The previous operator failed to share ILI tool performance data with the ILI service
18 provider that could have enabled them to regrade the ILI more accurately.
- 19 • Some conditions can be more challenging as ILI tools have technical limitations.
20 ILI tool vendors have limits or restrictions on tool operation to get valid results.
- 21 • Some pipeline operators make biased interpretations of the ILI data or fail to
22 account for tool error.

23 41. His point seems to be “it’s complicated and has to be done right”. That applies to all
24 228,000 miles of hazardous liquid transmission pipelines not to mention all 298,000 miles of onshore
25 natural gas transmission pipelines. He has not shown through any rational, data-based analysis that it is
26 somehow *more true* for Las Flores than any of those other systems.

1 **2. Section VI. The Greatest Threat ... Is From External Corrosion**

2 42. Mr. Kuprewicz questions whether the reliance of the Consent Decree and the OSFM state
3 waiver on ILI to manage the external corrosion threat can prevent another failure. He points to the failure
4 of the previous operator, Plains, to rigorously validate the performance of the ILI tools and account for
5 the tool performance when establishing appropriate field response to conclude that "...current ILI
6 technology does not ... reliably identify all forms of external corrosion most likely present on much of
7 the pipeline". Mr. Kuprewicz leaps to this conclusion without recognizing several significant facts.
8 Firstly, Sable is not Plains, and will be held to higher standards of performance. Secondly, different tools
9 with differing technology will be used (most importantly, ultrasonic metal loss tools), and will be run
10 more frequently. Third, he does not identify what kind of corrosion will be present on much of the pipeline
11 that he claims will be undetectable. His position are biased and misleading, being based on pejorative
12 sentiments intended to be alarming while ignoring important facts.

13 43. Later in this section he discusses the relationship between the insulation and coating system
14 and the inability of cathodic protection to function effectively. As I have pointed out earlier, ineffective
15 CP is a common occurrence for pipelines for a variety of reasons. ILI, implemented correctly and with
16 due understanding of its limitations, can be used to monitor the condition of the pipeline in an absence of
17 effective CP. Mr. Kuprewicz has not provided factual proof that ILI as specified by the OSFM state
18 waiver cannot effectively be used for that purpose.

19 **3. Section VII. High Pipeline Operating Temperatures Accelerate All Forms of**
20 **Corrosion**

21 44. Mr. Kuprewicz claims that due to the elevated temperatures, the corrosion rate will be 32
22 times faster than under normal conditions. There is little doubt that corrosion rates will be higher than for
23 many other pipelines that don't operate at elevated temperatures. But Mr. Kuprewicz is speculating as to
24 the corrosion rate being 32 times faster, nevertheless the OSFM has implemented in the state waiver an
25 accelerated detection and protection program as discussed above in my analysis of Mr. Kuprewicz's
26 Opinion (e). This was established by PHMSA's third party consultants. The OSFM has specified that
27 corrosion rates be established to assure that response times for repairs and maintenance are appropriate
28 with a high margin of safety.

1 **4. Section VIII. The CD Fails to Required Adequate IM Processes to Prevent**
2 **Another Rupture**

3 45. Mr. Kuprewicz complains that the Consent Decree does not address important technical
4 issues, such as “cracking threats most likely to to exist on major segments of the pipeline”. The Line 901
5 failure was not due to cracking, no cracking was identified in the failure investigation, and in my opinion
6 as discussed previously, cracking is unlikely to be significant. In any case, the OSFM state waiver, which
7 he does not discuss in this section of his Declaration, does address numerous important technical issues
8 including requiring running crack detection ILI tools. This appears to be a deliberate omission by Mr.
9 Kuprewicz to bias the reader.

10 **5. Section IX. The Pipelines Cannot Be Made as Safe as New Pipelines**

11 46. Mr. Kuprewicz summarizes the design aspects of the pipelines that contribute to corrosion
12 occurring readily and quickly. He states that it will be impossible to return the pipeline to a corrosion-
13 free as-new condition. Actually, all pipelines, even a newly constructed pipeline, will require condition
14 assessment by ILI surveillance and subsequent repairs and maintenance, and will require an ongoing TIMP
15 program to remain safe (all of which is being done on this pipeline system as per the OSFM). Almost
16 every pipeline has some corrosion on it, even modern pipelines. Testing has shown that at the common
17 maximum operating stress levels of 72% SMYS, it is virtually impossible for a pipeline to fail with
18 corrosion up to 50% wall loss. Sable’s planned operating pressure combined with OSFM requirements
19 that they repair up to 40% wall losses further enhances pipeline integrity. This provides many
20 opportunities to discover the pipeline conditions that may require repairs. Using differing ILI technologies
21 on a frequent basis can be relied on to discover that, in my opinion and experience. Mr. Kuprewicz’s
22 opinion is based on an incomplete recognition of the facts concerning this pipeline.

23 **6. Section X. Conclusion**

24 47. Mr. Kuprewicz states in his Conclusion that hydrostatic testing and ILI will be ineffective
25 to address the possible threats, and it would imprudent to rely on such assessments. He has not critically
26 evaluated whether the specific and multiple ILI technologies specified by the OSFM state waiver are in
27 fact inadequate and, if so, why. He also states that using the wrong ILI tools can make the risk of an oil
28 spill orders of magnitude worse, though he has not stated why the specified ILI technology is of the wrong

1 type, nor presented a risk assessment quantifying the increased magnitude of the postulated oil spill. He
2 concludes that the Las Flores Pipeline System is unusually dangerous due to its age and design flaws.
3 This opinion was built on an aggregation of preceding claims each made without supporting data or even
4 contrary to known or knowable facts. As such it is nonfactual and noncredible.

5 **D. Positions Stated in Kuprewicz’s Declaration Exhibit C**

6 48. Mr. Kuprewicz supplements the technical issues and the opinions in his Declaration with
7 additional positions stated in his Exhibit C “Observations on OSFM Letters of Decision for State Waiver
8 Requests on Line CA-324 and CA-325A/B Related to Possible Restart”, February 21, 2025. For the most
9 part, he relies on the same erroneous positions taken without supporting data or analysis, or half-truths
10 presented in an incomplete way to bias the reader, as have been discussed above. Therefore, a detailed
11 point by point evaluation of Exhibit C is already addressed in this declaration and need not be repeated
12 here.

13 **IV. Exhibits**

14 49. In forming the opinions stated herein, I reviewed and considered the following documents
15 and the facts stated therein:

- 16 a. Declaration of Richard B. Kuprewicz in Support of Petitioners’ *Ex Parte* Application for
17 Stay, Order to Show Cause and Temporary Restraining order, June 3, 2025, a true and
18 correct copy of which is attached hereto as **Exhibit B**.
- 19 b. US Department of Transportation, Pipeline and Hazardous Materials Safety
20 Administration, Office of Pipeline Safety, Corrective Action Order, CPF NO. 5-2015-
21 5011H, May 21, 2015, a true and correct copy of which is attached hereto as **Exhibit C**.
- 22 c. United States District Court, Central District of California, Civil Action NO. 2:20-cv-
23 02415, CONSENT DECREE, Filed 03/13/20, a true and correct copy of which is attached
24 hereto as **Exhibit D**.
- 25 d. Department of Forestry and Fire Protection, Office of the State Fire Marshal, Letter of
26 Decision on the state Waiver Request for Limited Effectiveness of Cathodic Protection on
27 Thermally Insulated Pipeline and Corrosion of or Along a Longitudinal Seam Weld (CA-
28 324), Dec. 17, 2024, a true and correct copy of which is attached hereto as **Exhibit E**.

- 1 e. Department of Forestry and Fire Protection, Office of the State Fire Marshal, Letter of
2 Decision on the State Waiver Request for Limited Effectiveness of Cathodic Protection on
3 Thermally Insulated Pipeline and Corrosion of or Along a Longitudinal Seam Weld (CA-
4 325A/B), Dec. 17, 2024, a true and correct copy of which is attached hereto as **Exhibit F.**
- 5 f. US Department of Transportation, Pipeline and Hazardous Materials Safety
6 Administration, “Failure Investigation Report, Plains Pipeline LP, Line 901 Crude Oil
7 Release, May 19, 2025, Santa Barbara California”, May 2016, a true and correct copy of
8 which is attached hereto as **Exhibit G.**
- 9 g. Norfleet, D.M., “Line 901 Release (5/19/25): Mechanical and Metallurgical Testing”,
10 DNV-GL, Final Report No. OAPUS309DNOR (PP136049), September 18, 2015,
11 Appendix M to PHMSA FIR, a true and correct copy of which is attached hereto as **Exhibit**
12 **H.**
- 13 h. US Department of Transportation, Pipeline and Hazardous Materials Safety
14 Administration, Advisory Bulletin ADB 17-01, 82 FR 14106, Thursday, March 16, 2017,
15 a true and correct copy of which is attached hereto as **Exhibit I.**
- 16 i. Kiefner, J.F., “Defect assessment – 1: Modified equation aids integrity management”, Oil
17 & Gas Journal, Oct. 6, 2008 and “Defect assessment – 2: Modified Ln-Secant equation
18 improves failure prediction”, Oil & Gas Journal, Oct. 13, 2008, a true and correct copy of
19 which is attached hereto as **Exhibit J.**
- 20 j. McMahan, T.P., Amend, B., Harper, W., Bubenik, T., Evans, K., Rosenfeld, M., and Li,
21 Y., “Evaluation of Selective Seam Weld Corrosion Susceptibility”, 14th International
22 Pipeline Conference, IPC2024-121806, Calgary, 2024, a true and correct copy of which is
23 attached hereto as **Exhibit K.**
- 24 k. National Energy Board, “Stress Corrosion Cracking on Canadian Oil and Gas Pipelines”,
25 Report of the Inquiry, MH-2-05, December 1996, a true and correct copy of which is
26 attached hereto as **Exhibit L.**
- 27 l. Michael Baker Jr. Engineering and Kiefner & Associates, Inc., “Spike Hydrostatic Test
28 Evaluation”, Final Report to Department of Transportation, Research and Special

1 Programs Administration, Office of Pipeline Safety, Technical Task Order No. 6 (TTO-6),
2 Delivery Order DTRS56-02-D-70036, July 2004, a true and correct copy of which is
3 attached hereto as **Exhibit M.**

4 m. Rosenfeld, M.J., “Hydrostatic pressure spike testing of pipelines: why and when?”, Journal
5 of Pipeline Engineering, 2013, a true and correct copy of which is attached hereto as
6 **Exhibit N.**

7 n. US Department of Transportation, Pipeline and Hazardous Materials Safety
8 Administration, Advisory Bulletin ADB 17-01, 82 FR 14106, Thursday, March 16, 2017,
9 a true and correct copy of which is attached hereto as **Exhibit O.**

10 o. Kiefner, J.F., and Vieth, P.H., “Project PR 3-805, A Modified Criterion for Evaluating the
11 Remaining Strength of Corroded Pipe”, American Gas Association, Cat. No. L51609, Dec.
12 22, 1989, a true and correct copy of which is attached hereto as **Exhibit P.**

13 p. American Petroleum Institute, “Managing System Integrity for Hazardous Liquid
14 Pipelines”, API Recommended Practice 1160, Third Edition, February 2019, a true and
15 correct copy of which is attached hereto as **Exhibit Q.**

16 q. Nestleroth, J.B. and Rosenfeld, M.J., “Changes to In-Line Inspection Approaches to
17 Consider with Changing Regulations”, Pipeline Pigging and Integrity Management
18 Conference, Houston, 2020, a true and correct copy of which is attached hereto as **Exhibit**
19 **R.**

20 r. Harris, C. “Assessing Mechanical Damage Using Multiple Data Sets in Inline Inspection”,
21 Pipeline Technology Conference, Berlin, 2013, a true and correct copy of which is attached
22 hereto as **Exhibit S.**

23 s. Thompson, R., Gardner, R., Dwyer, K., Gonzales, R., Corbett, A., Solano, G., “Pipeline
24 Integrity Management of CSCC using multiple ILI technologies”, Pipeline Pigging and
25 Integrity Management Conference, Houston, 2021, a true and correct copy of which is
26 attached hereto as **Exhibit T.**

27 t. Krieg, M., Nestleroth, J.B., Hennig, T., and Haines, H., “In-Line Inspection in Lieu of
28 Hydrostatic Testing for Low Frequency Electric Resistance Welded Pipe”, 12th

1 International Pipeline Conference, IPC2018-78522, Calgary, 2018, a true and correct copy
2 of which is attached hereto as **Exhibit U**.

3 I declare under penalty of perjury under the laws of the State of California that the foregoing is
4 true and correct. Executed this 7th day of July, 2025, in Granville, Ohio.

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9 _____
Michael J. Rosenfeld

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VOLUME 1 OF 4
(EXHIBITS A – F)
TO DECLARATION OF
MICHAEL ROSENFELD

EXHIBIT A

Michael J. Rosenfeld, PE

Chief Engineer, Managing Member
RSI Pipeline Solutions, LLC
740-398-9543, mrosenfeld@rsi-ps.com
or mjrosenfeld57@gmail.com



Summary

Experienced consultant in the subject of oil and gas pipeline fitness-for-service; pipeline integrity; pipeline design, materials, construction, and maintenance; and pipeline regulations and standards.

Education

Bachelor of Science in Engineering – Mechanical Engineering, University of Michigan, 1979
Master of Science in Mechanical Engineering, Carnegie-Mellon University, 1981

Areas of Competency

Pipeline defects, fitness for service assessment
Metallurgical failure analysis
Root cause failure analysis
Pipeline integrity management
Pipeline risk analysis
ASME B31.4, B31.8, B31.8S and related standards
API 1104, 1160, 1176, and related standards
49 CFR Parts 192 and 195
Pipeline design, materials, and construction
Pipeline maintenance and repair
Research and development
Training and seminars

Work Experience

RSI Pipeline Solutions LLC

Chief Engineer, 2019-Present

Co-founder of RSI Pipeline Solutions LLC, 2019 and Managing Member. Providing technical services in support of the oil and gas pipeline industry in matters such as pipeline fitness for service, pipeline integrity management, pipeline failure root cause analysis, regulatory compliance, pipeline codes and standards development, research, and training. Recently completed an industry-funded landmark study on the integrity threat of pipe body hard spots in vintage line pipe.

Kiefner Applus-RTD**Chief Engineer, 2012-2019**

Developed company practice for conducting root cause failure analysis. Developed process for determining the most probable grade of undocumented line pipe based on measured material strength and steel chemistry. Developed processes for establishing the probable design pressure of undocumented pipelines. Provided expert testimony or opinions in support of litigation.

Kiefner & Associates, Inc.**President, 2002-2011**

Conducted research on the effects of pressure cycle fatigue in pipelines, and the effects of pipe diameter expansion due to material yielding. Worked with pipeline operators to improve their processes for evaluating pipeline fitness for service, risk assessment, and other integrity management practices. Effectively doubled the size of Kiefner & Associates with the addition of a dedicated material testing facility, a corrosion group, and other service areas such as geotechnical and in-line inspection analysis.

Senior Structural Engineer, 1991-2002

Performed stress analyses of pipelines subjected to external loadings. Developed monitoring and mitigation plans for pipelines affected by longwall mining subsidence. Performed qualifications testing of welding procedures and welder performance. Conducted research on the effects of mechanical damage on pipelines and originated the concept of evaluating severity of pipeline indentations based on strains of deformation. Authored revised allowable stress limits and revise repair requirements for ASME B31.8. Performed several dozen pipeline failure investigations.

Battelle Memorial Institute, Senior Research Engineer, 1984-1991

Performed stress analysis, fracture mechanics analysis, and design engineering for various industrial and military equipment applications. Patented an innovative design to reduce material usage and improve performance in a household appliance motor housing. Performed failure analysis of high-pressure piping. Conducted industry funded research on effectiveness of gas pipeline in-line inspection and on structural behavior of piping components affected by corrosion.

EDS Nuclear / Impel Corporation, Engineer II, 1981-1984

Performed stress analysis of nuclear power plant piping, piping supports, building structures, and electrical components for seismic and other loadings using finite element analysis and traditional calculation methods. Performed field engineering in support of plant turnovers.

Industry Activity

Past Vice Chair, Interim Chair, ASME B31.8 Committee

Past Chair, ASME B31.8 Subgroup on Design, Materials, and Construction

Member, B31.8 Task Groups on Hydrogen and CO₂ pipelines

Member, ASME B31 Standards Committee

Member, ASME B31 Mechanical Design Technical Committee

Instructor, ASME Continuing Education Short Courses on ASME B31.4, B31.8, B31.8S, B31.12

Former Member at Large, ASME Board of Pressure Technology Codes and Standards

Former Member, Joint ASCE-ASME Task Group on Design of Buried Pipe

Former Member, API RP 1117 Task Force on In-Service Relocation of Pipelines, 1st Edition

Former Member, Work Group on API RP 1176 Assessment and Management of Cracking in Pipelines, 1st Edition

Former Member, Work Group on API RP 1160 Managing System Integrity for Hazardous Liquid Pipelines, 3rd Edition

International Pipeline Conference 2006, Session Chair, Mechanical Damage

International Pipeline Conference 2010, Session Chair, Structural Integrity I

ASME Fellow, awarded January 2012

ASME B31 Forever Award for Excellence in Piping Engineering, awarded September 2020

Registered Professional Engineer, State of Ohio, License No. E-55441

Publications

Authored or coauthored over 130 published articles and public conference presentations. List available upon request.

EXHIBIT B

1 LINDA KROP (Bar No. 118773)
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3 TARA C. RENGIFO (Bar No. 307670)
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ENVIRONMENTAL DEFENSE CENTER
5 906 Garden Street
Santa Barbara, CA 93101
6 Phone: (805) 963-1622; Fax: (805) 962-3152

7 *Attorneys for Petitioners/Plaintiffs*

8 **SUPERIOR COURT OF THE STATE OF CALIFORNIA**
9 **IN AND FOR THE COUNTY OF SANTA BARBARA**

10 ENVIRONMENTAL DEFENSE CENTER, a
11 California non-profit corporation; GET OIL
12 OUT!, a California non-profit corporation;
SANTA BARBARA COUNTY ACTION
13 NETWORK, a California non-profit corporation;
14 SIERRA CLUB, a national non-profit
corporation; and SANTA BARBARA
15 CHANNELKEEPER, a California non-profit
corporation,

16 **Petitioners and Plaintiffs,**

17 vs.

18 CALIFORNIA DEPARTMENT OF
19 FORESTRY AND FIRE PROTECTION, by and
through the OFFICE OF THE STATE FIRE
20 MARSHAL, an agency of the State of
California; DANIEL BERLANT, in his official
21 capacity as State Fire Marshal; and DOES 1 to
22 10, inclusive,

23 **Respondents and Defendants,**

24 and

25 SABLE OFFSHORE CORP., a Delaware
26 corporation; and PACIFIC PIPELINE
COMPANY, a Delaware Corporation,
27

28 **Real Parties in Interest.**

Case No.: 25CV02247

**DECLARATION OF RICHARD B.
KUPREWICZ IN SUPPORT OF
PETITIONERS' EX PARTE APPLICATION
FOR STAY, ORDER TO SHOW CAUSE AND
TEMPORARY RESTRAINING ORDER**

*[Filed concurrently with Ex Parte Application for
Stay, Order to Show Cause and Temporary
Restraining Order]*

Date: June 3, 2025
Time: 8:30 a.m.
Dept.: 4
Judge: Hon. Donna G. Geck

Action Filed: April 15, 2025
Trial: None Set

1 that I instituted and developed for the City of Bellingham, Washington, to assure that a ruptured pipeline
2 there could be restarted and operated safely. I also served for seven years as a member of the
3 Washington State Citizens Committee on Pipeline Safety (“CCOPS”). Positions to CCOPS are
4 appointed by the Governor.

5 5. I am an expert in oil and gas pipeline safety and risk management analysis based on my
6 training, education, and experience. Attached as **Exhibit A** is my curriculum vitae.

7 6. I have investigative expertise in the topic of various forms of seam corrosion, such as
8 selective seam corrosion, stress corrosion cracking, and am a recognized expert in early vintage cracking
9 having investigated pipeline ruptures associated with these types of cracking threats.

10 7. I was asked by the Environmental Defense Center (EDC) and Center for Biological
11 Diversity (CBD) to utilize my experience and expertise to evaluate safety and integrity issues regarding
12 the proposal to restart the Las Flores Pipeline System, which includes CA-324 and CA-325A/B (“the
13 Pipelines”). A true and correct copy of my report, titled *Evaluation of Las Flores Pipeline System*
14 *Startup Proposal*, dated December 20, 2024, is attached to this declaration as **Exhibit B**.

15 8. The report sets forth my opinion, based on my review of the Consent Decree and other
16 documents, references, and regulations related to the Pipelines, including: the “Failure Investigation
17 Report, Plains Pipeline, LP, Line 901 Crude Oil Release, May 19, 2015 Santa Barbara County,”
18 prepared by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety
19 Administration (May 2016); DNV-G Final Report, “Line 901 Release (5/15/15) Mechanical and
20 Metallurgical Testing – Report No.: OAPUS309DNOR (PP136049)” (September 18, 2015); PHMSA –
21 In the Matter of Plains Pipeline, LP, Respondent, “Amendment No. 1 to the Corrective Action Order –
22 CPF No. 5-2015-5011H;” CA Code CCR 19 § 2111 – Risk Analysis (2) Pipeline Description (A); 49
23 CFR § 195.304 Test Pressure; and Sable’s website concerning, “Sable Offshore Corp. Provides Update
24 on Pacific Pipeline Company Operations,” October 28, 2024, at:

25 <https://www.sableoffshore.com/news/news-details/2024/Sable-Offshore-Corp.-Provides-Update-on->
26 [Pacific-Pipeline-Company-Operations/default.aspx](https://www.sableoffshore.com/news/news-details/2024/Sable-Offshore-Corp.-Provides-Update-on-Pacific-Pipeline-Company-Operations/default.aspx). In summary, I identified the following technical
27 issues concerning the proposed restart of the Pipelines:
28

1 a. The design of the Pipelines renders the federal mandated cathodic protection system,
2 intended to help address pipeline external corrosion, ineffective.

3 b. Current inline inspection (ILI) technologies cannot adequately assess all forms of
4 external corrosion threats that most likely exist on the Pipelines.

5 c. The high operating temperatures needed to reduce the viscosity of the heavy crude oil
6 significantly accelerate all forms of external pipeline corrosion that will not be mitigated by the
7 ineffective cathodic protection system once the Pipelines go into operation.

8 d. Segments at risk of corrosion related cracking (i.e., stress corrosion cracking or
9 selective seam corrosion cracking) are at the highest risk of failure.

10 e. The poorly designed Pipelines cannot be made as safe as new pipelines.

11 9. Following the preliminary approval of the State Waivers for the pipelines, EDC and
12 CBD asked me to review and evaluate the Letters of Decision on the State Waiver Request for Limited
13 Effectiveness of Cathodic Protection on Thermally Insulated Pipeline and Corrosion of or Along a
14 Longitudinal Seam Weld for CA-324 and CA-325A/B (“State Waivers”). A true and correct copy of my
15 report, titled *Observations on OSFM Letters of Decision for State Waiver Requests on Line CA-324 and*
16 *CA-325A/B Related to Possible Restart*, dated February 21, 2025, is attached to this declaration as

17 **Exhibit C.**

18 10. The report sets forth my opinion based on my review of the State Waivers and related
19 documents, references, and regulations, including: Pacific Pipeline Company (Aka now as Sable/PPC)
20 letter to OSFM, “Subject Pacific Pipeline Company (OPID 40475) State Waiver Application for the Las
21 Flores Pipeline CA-324 (OSFM #00115),” July 10, 2023, p. 5 related to MFL-C February 2020 ILI run;
22 49 CFR § 452(h)(4)(iii)(H); PHMSA website: [https://www.phmsa.dot.gov/pipeline/special-permits-
23 state-waivers/special-permits-and-state-waivers-overview](https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-and-state-waivers-overview); Plains Administrative Draft EIR, “Plains
24 Replacement Pipeline Project,” February 2022; and “Failure Investigation Report, Plains Pipeline, LP,
25 Line 901 Crude Oil Release, May 19, 2015 Santa Barbara County,” prepared by the U.S. Department of
26 Transportation Pipeline and Hazardous Materials Safety Administration (May 2016). My opinion, as set
27 forth in my report, is as follows:
28

1 a. The reliance on ILI technology to identify corrosion threats before failure is
2 misplaced because such tools can miss a lot of cracks. There are multiple forms of corrosion on the
3 Pipelines, and ILI is insufficient to detect some of them.

4 b. The proposed hydrotests are also insufficient to address certain types of corrosion or
5 predict corrosion growth. For example, MOP hydrotests are not adequate to test for crack forming
6 potential on the Pipelines.

7 c. The State Waivers do not assure adequate spike hydrotesting, which is a method to
8 address various forms of crack forming potential. The values for the spike test on Line 324 are too low
9 for corrosion cracking screening and evaluation. Hydrotesting for Lines 325 A and B must be conducted
10 in segments given the elevation changes. It is unclear, however, whether the testing parameters are
11 adequate for Line 325A due to missing information. In addition, the Waivers do not appear to require
12 any hydrotesting for Line 325B.

13 d. A key corrosion performance tracking process set in the State Waivers for the
14 Pipelines is missing. This information, which helps identify possible corrosion “hot spots,” is especially
15 important given the history of extensive corrosion on the Pipelines.

16 e. The State Waivers will not provide an equal or greater level of safety as if the
17 Pipelines were equipped with an effective cathodic protection system to avoid pipeline failure due to
18 external corrosion. The current design of the Pipeline renders the cathodic protection system ineffective.
19 External corrosion on the Pipelines is exacerbated by operation of the Pipelines at elevated temperatures,
20 which seriously increases the corrosion rate.

21 11. Based on the facts I reviewed and my professional analysis, in my opinion the Las Flores
22 Pipeline System is not safe to operate, even if the conditions in the Fire Marshal’s State Waivers are
23 fulfilled.

24 I declare under penalty of perjury under the laws of the State of California that the foregoing is
25 true and correct.

26 Executed this 28th day of May 2025, in Nipomo, California.

27 

28 _____
Richard B. Kuprewicz

Exhibit Index

[Exhibits Supporting Declaration of Richard B. Kuprewicz in Support of Petitioners' Ex Parte Application for Stay, Order to Show Cause and Temporary Restraining Order]

Exhibit	Description	Page No.
A	Curriculum vitae of Richard B. Kuprewicz	7-16
B	Evaluation of Las Flores Pipeline System Startup Proposal, dated December 20, 2024	17-43
C	Observations on OSFM Letters of Decision for State Waiver Requests on Line CA-324 and CA-325A/B Related to Possible Restart, dated February 21, 2025	44-55

Exhibit A

Curriculum Vitae.

Richard B. Kuprewicz

8151 164th Ave NE
Redmond, WA 98052

Tel: 425-802-1200 (Office)

E-mail: kuprewicz@comcast.net

Profile:

As president of Accufacts Inc., I specialize in gas and liquid pipeline investigation, auditing, risk management, siting, construction, design, operation, maintenance, training, SCADA, leak detection, management review, emergency response, and regulatory development and compliance. I have consulted for various local, state and federal agencies, NGOs, the public, and pipeline industry members on pipeline regulation, operation and design, with particular emphasis on operation in unusually sensitive areas of high population density or environmental sensitivity.

Employment:

Accufacts Inc.

1999 – Present

Pipeline regulatory advisor, incident investigator, and expert witness on all matters related to gas and liquid pipeline siting, design, operation, maintenance, risk analysis, and management.

Position: President
Duties: > Full business responsibility
> Technical Expert

Alaska Anvil Inc.

1993 – 1999

Engineering, procurement, and construction (EPC) oversight for various clients on oil production facilities, refining, and transportation pipeline design/operations in Alaska.

Position: Process Team Leader
Duties: > Led process engineers group
> Review process designs
> Perform hazard analysis
> HAZOP Team leader
> Assure regulatory compliance in pipeline and process safety management

ARCO Transportation Alaska, Inc.

1991 - 1993

Oversight of Trans Alaska Pipeline System (TAPS) and other Alaska pipeline assets for Arco after the Exxon Valdez event.

Position: Senior Technical Advisor
Duties: > Access to all Alaska operations with partial Arco ownership
> Review, analysis of major Alaska pipeline projects

ARCO Transportation Co.

1989 – 1991

Responsible for strategic planning, design, government interface, and construction of new gas pipeline projects, as well as gas pipeline acquisition/conversions.

Position: Manager Gas Pipeline Projects
Duties: > Project management
> Oil pipeline conversion to gas transmission
> New distribution pipeline installation
> Full turnkey responsibility for new gas transmission pipeline, including FERC filing

Four Corners Pipeline Co.

1985 – 1989

Managed operations of crude oil and product pipelines/terminals/berths/tank farms operating in western U.S., including regulatory compliance, emergency and spill response, and telecommunications and SCADA organizations supporting operations.

- Position:** Vice President and Manager of Operations
Duties:
- > Full operational responsibility
 - > Major ship berth operations
 - > New acquisitions
 - > Several thousand miles of common carrier and private pipelines

Arco Product CQC Kiln

1985

Operations manager of new plant acquisition, including major cogeneration power generation, with full profit center responsibility.

- Position:** Plant Manager
Duties:
- > Team building of new facility that had been failing
 - > Plant design modifications and troubleshooting
 - > Setting expense and capital budgets, including key gas supply negotiations
 - > Modification of steam plant, power generation, and environmental controls

Arco Products Co.

1981 - 1985

Operated Refined Product Blending, Storage and Handling Tank Farms, as well as Utility and Waste Water Treatment Operations for the third largest refinery on the west coast.

- Position:** Operations Manager of Process Services
Duties:
- > Modernize refinery utilities and storage/blending operations
 - > Develop hydrocarbon product blends, including RFGs
 - > Modification of steam plants, power generation, and environmental controls
 - > Coordinate new major cogeneration installation, 400 MW plus

Arco Products Co.

1977 - 1981

Coordinated short and long-range operational and capital planning, and major expansion for two west coast refineries.

- Position:** Manager of Refinery Planning and Evaluation
Duties:
- > Establish monthly refinery volumetric plans
 - > Develop 5-year refinery long range plans
 - > Perform economic analysis for refinery enhancements
 - > Issue authorization for capital/expense major expenditures

Arco Products Co.

1973 - 1977

Operating Supervisor and Process Engineer for various major refinery complexes.

- Position:** Operations Supervisor/Process Engineer
Duties:
- > FCC Complex Supervisor
 - > Hydrocracker Complex Supervisor
 - > Process engineer throughout major integrated refinery improving process yield and energy efficiency

Qualifications:

Served for over fifteen years as a member representing the public on the federal Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC), a technical committee established by Congress to advise PHMSA on pipeline safety regulations.

Committee members are appointed by the Secretary of Transportation.

Served seven years, including position as its chairman, on the Washington State Citizens Committee on Pipeline Safety (CCOPS).

Positions are appointed by the governor of the state to advise federal, state, and local governments on regulatory matters related to pipeline safety, routing, construction, operation and maintenance.

Served on Executive subcommittee advising Congress and PHMSA on a report that culminated in new federal rules concerning Distribution Integrity Management Program (DIMP) gas distribution pipeline safety regulations.

As a representative of the public, advised the Office of Pipeline Safety on proposed new liquid and gas transmission pipeline integrity management rulemaking following the pipeline tragedies in Bellingham, Washington (1999) and Carlsbad, New Mexico (2000).

Member of Control Room Management committee assisting PHMSA on development of pipeline safety Control Room Management (CRM) regulations.

Certified and experienced HAZOP Team Leader associated with process safety management and application.

Education:

MBA (1976)

BS Chemical Engineering (1973)

BS Chemistry (1973)

Pepperdine University, Los Angeles, CA

University of California, Davis, CA

University of California, Davis, CA

Publications in the Public Domain:

1. "An Assessment of First Responder Readiness for Pipeline Emergencies in the State of Washington," prepared for the Office of the State Fire Marshall, by Hanson Engineers Inc., Elway Research Inc., and Accufacts Inc., and dated June 26, 2001.
2. "Preventing Pipeline Failures," prepared for the State of Washington Joint Legislative Audit and Review Committee ("JLARC"), by Richard B. Kuprewicz, President of Accufacts Inc., dated December 30, 2002.
3. "Pipelines - National Security and the Public's Right-to-Know," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated May 14, 2003.
4. "Preventing Pipeline Releases," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated July 22, 2003.
5. "Pipeline Integrity and Direct Assessment, A Layman's Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated November 18, 2004.
6. "Public Safety and FERC's LNG Spin, What Citizens Aren't Being Told," jointly authored by Richard B. Kuprewicz, President of Accufacts Inc., Clifford A. Goudey, Outreach Coordinator MIT Sea Grant College Program, and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated May 14, 2005.
7. "A Simple Perspective on Excess Flow Valve Effectiveness in Gas Distribution System Service Lines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated July 18, 2005.
8. "Observations on the Application of Smart Pigging on Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated September 5, 2005.
9. "The Proposed Corrib Onshore System - An Independent Analysis," prepared for the Centre for Public Inquiry by Richard B. Kuprewicz, dated October 24, 2005.
10. "Observations on Sakhalin II Transmission Pipelines," prepared for The Wild Salmon Center by Richard B. Kuprewicz, dated February 24, 2006.
11. "Increasing MAOP on U.S. Gas Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2006. This paper was also published in the June 26 and July 1, 2006 issues of the Oil & Gas Journal and in the December 2006 issue of the UK Global Pipeline Monthly magazines.
12. "An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick," prepared for the Friends of Rockwood Park, by Richard B. Kuprewicz, dated September 16, 2006.
13. "Commentary on the Risk Analysis for the Proposed Emera Brunswick Pipeline Through Saint John, NB," by Richard B. Kuprewicz, dated October 18, 2006.
14. "General Observations On the Myth of a Best International Pipeline Standard," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2007.
15. "Observations on Practical Leak Detection for Transmission Pipelines – An Experienced Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated August 30, 2007.
16. "Recommended Leak Detection Methods for the Keystone Pipeline in the Vicinity of the Fordville Aquifer," prepared for TransCanada Keystone L.P. by Richard B. Kuprewicz, President of Accufacts Inc., dated September 26, 2007.
17. "Increasing MOP on the Proposed Keystone XL 36-Inch Liquid Transmission Pipeline," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated February 6, 2009.
18. "Observations on Unified Command Drift River Fact Sheet No 1: Water Usage Options for the current Mt. Redoubt Volcano threat to the Drift River Oil Terminal," prepared for Cook Inletkeeper by Richard B. Kuprewicz, dated April 3, 2009.

19. "Observations on the Keystone XL Oil Pipeline DEIS," prepared for Plains Justice by Richard B. Kuprewicz, dated April 10, 2010.
20. "PADD III & PADD II Refinery Options for Canadian Bitumen Oil and the Keystone XL Pipeline," prepared for the Natural Resources Defense Council (NRDC), by Richard B. Kuprewicz, dated June 29, 2010.
21. "The State of Natural Gas Pipelines in Fort Worth," prepared for the Fort Worth League of Neighborhoods by Richard B. Kuprewicz, President of Accufacts Inc., and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated October, 2010.
22. "Accufacts' Independent Observations on the Chevron No. 2 Crude Oil Pipeline," prepared for the City of Salt Lake, Utah, by Richard B. Kuprewicz, dated January 30, 2011.
23. "Accufacts' Independent Analysis of New Proposed School Sites and Risks Associated with a Nearby HVL Pipeline," prepared for the Sylvania, Ohio School District, by Richard B. Kuprewicz, dated February 9, 2011.
24. "Accufacts' Report Concerning Issues Related to the 36-inch Natural Gas Pipeline and the Application of Appleview, LLC Premises: 7009 and 7010 River Road, North Bergen, NJ," prepared for the Galaxy Towers Condominium Association Inc., by Richard B. Kuprewicz, dated February 28, 2011.
25. "Prepared Testimony of Richard B. Kuprewicz Evaluating PG&E's Pipeline Safety Enhancement Plan," submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012.
26. "Evaluation of the Valve Automation Component of PG&E's Safety Enhancement Plan," extracted from full testimony submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012, Extracted Report issued February 20, 2012.
27. "Accufacts' Perspective on Enbridge Filing to NEB for Modifications on Line 9 Reversal Phase I Project," prepared for Equiterre Canada, by Richard B. Kuprewicz, Accufacts Inc., dated April 23, 2012.
28. "Accufacts' Evaluation of Tennessee Gas Pipeline 300 Line Expansion Projects in PA & NJ," prepared for the Delaware RiverKeeper Network, by Richard B. Kuprewicz, Accufacts Inc., dated June 27, 2012.
29. "Impact of an ONEOK NGL Pipeline Release in At-Risk Landslide and/or Sinkhole Karst Areas of Crook County, Wyoming," prepared for landowners, by Richard B. Kuprewicz, Accufacts Inc., and submitted to Crook County Commissioners, dated July 16, 2012.
30. "Impact of Processing Dilbit on the Proposed NPDES Permit for the BP Cherry Point Washington Refinery," prepared for the Puget Soundkeeper Alliance, by Richard B. Kuprewicz, Accufacts Inc., dated July 31, 2012.
31. "Analysis of SWG's Proposed Accelerated EVPP and P70VSP Replacement Plans, Public Utilities Commission of Nevada Docket Nos. 12-02019 and 12-04005," prepared for the State of Nevada Bureau of Consumer Protection, by Richard B. Kuprewicz, Accufacts Inc., dated August 17, 2012.
32. "Accufacts Inc. Most Probable Cause Findings of Three Oil Spills in Nigeria," prepared for Bohler Advocaten, by Richard B. Kuprewicz, Accufacts Inc., dated September 3, 2012.
33. "Observations on Proposed 12-inch NGL ONEOK Pipeline Route in Crook County Sensitive or Unstable Land Areas," prepared by Richard B. Kuprewicz, Accufacts Inc., dated September 13, 2012.
34. "Findings from Analysis of CEII Confidential Data Supplied to Accufacts Concerning the Millennium Pipeline Company L.L.C. Minisink Compressor Project Application to FERC, Docket No. CP11-515-000," prepared by Richard B. Kuprewicz, Accufacts Inc., for Minisink Residents for Environmental Preservation and Safety (MREPS), dated November 25, 2012.
35. "Supplemental Observations from Analysis of CEII Confidential Data Supplied to Accufacts Concerning Tennessee Gas Pipeline's Northeast Upgrade Project," prepared by Richard B. Kuprewicz, Accufacts Inc., for Delaware RiverKeeper Network, dated December 19, 2012.

36. "Report on Pipeline Safety for Enbridge's Line 9B Application to NEB," prepared by Richard B. Kuprewicz, Accufacts Inc., for Equiterre, dated August 5, 2013.
37. "Accufacts' Evaluation of Oil Spill Joint Investigation Visit Field Reporting Process for the Niger Delta Region of Nigeria," prepared by Richard B. Kuprewicz for Amnesty International, September 30, 2013.
38. "Accufacts' Expert Report on ExxonMobil Pipeline Company Silvertip Pipeline Rupture of July 1, 2011 into the Yellowstone River at the Laurel Crossing," prepared by Richard B. Kuprewicz, November 25, 2013.
39. "Accufacts Inc. Evaluation of Transco's 42-inch Skillman Loop submissions to FERC concerning the Princeton Ridge, NJ segment," prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated June 26, 2014, and submitted to FERC Docket No. CP13-551.
40. Accufacts report "DTI Myersville Compressor Station and Dominion Cove Point Project Interlinks," prepared by Richard B. Kuprewicz for Earthjustice, dated August 13, 2014, and submitted to FERC Docket No. CP13-113-000.
41. "Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco's Leidy Southeast Expansion Project," prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated September 3, 2014, and submitted to FERC Docket No. CP13-551.
42. Accufacts' "Evaluation of Actual Velocity Critical Issues Related to Transco's Leidy Expansion Project," prepared by Richard B. Kuprewicz for Delaware Riverkeeper Network, dated September 8, 2014, and submitted to FERC Docket No. CP13-551.
43. "Accufacts' Report to Portland Water District on the Portland – Montreal Pipeline," with Appendix, prepared by Richard B. Kuprewicz for the Portland, ME Water District, dated July 28, 2014.
44. "Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco's Leidy Southeast Expansion Project," prepared by Richard B. Kuprewicz and submitted to FERC Docket No. CP13-551.
45. Review of Algonquin Gas Transmission LLC's Algonquin Incremental Market ("AIM Project"), Impacting the Town of Cortlandt, NY, FERC Docket No. CP14-96-0000, Increasing System Capacity from 2.6 Billion Cubic Feet (Bcf/d) to 2.93 Bcf/d," prepared by Richard B. Kuprewicz, and dated Nov. 3, 2014.
46. Accufacts' Key Observations dated January 6, 2015 on Spectra's Recent Responses to FERC Staff's Data Request on the Algonquin Gas Transmission Proposal (aka "AIM Project"), FERC Docket No. CP 14-96-000) related to Accufacts' Nov. 3, 2014 Report and prepared by Richard B. Kuprewicz.
47. Accufacts' Report on Mariner East Project Affecting West Goshen Township, dated March 6, 2015, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.
48. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing on the Proposed System Integrity Projects ("SIP") to the Mississippi Public Service Commission ("MPSC") under Docket No. 15-UN-049 ("Docket"), prepared by Richard B. Kuprewicz, dated June 12, 2015.
49. Accufacts' Report to the Shwx'owhamel First Nations and the Peters Band ("First Nations") on the Trans Mountain Expansion Project ("TMEP") filing to the Canadian NEB, prepared by Richard B. Kuprewicz, dated April 24, 2015.
50. Accufacts Report Concerning Review of Siting of Transco New Compressor and Metering Station, and Possible New Jersey Intrastate Transmission Pipeline Within the Township of Chesterfield, NJ ("Township"), to the Township of Chesterfield, NJ, dated February 18, 2016.
51. Accufacts Report, "Accufacts Expert Analysis of Humberplex Developments Inc. v. TransCanada Pipelines Limited and Enbridge Gas Distribution Inc.; Application under Section 112 of the National Energy Board Act, R.S.C. 1985, c. N-7," dated April 26, 2016, filed with the Canadian Nation Energy Board (NEB).
52. Accufacts Report, "A Review, Analysis and Comments on Engineering Critical Assessments as proposed in

PHMSA's Proposed Rule on Safety of Gas Transmission and Gathering Pipelines," prepared for Pipeline Safety Trust by Richard B. Kuprewicz, dated May 16, 2016.

53. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing to the Mississippi Public Utilities Staff, "Accufacts Review of Atmos Spending Proposal 2017 – 2021 (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 15, 2016.
54. Accufacts Report, "Accufacts Review of the U.S. Army Corps of Engineers (USACE) Environmental Assessment (EA) for the Dakota Access Pipeline ("DAPL")," prepared for Earthjustice by Richard B. Kuprewicz, dated October 28, 2016.
55. Accufacts' Report on Mariner East 2 Expansion Project Affecting West Goshen Township, dated January 6, 2017, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.
56. Accufacts Review of Puget Sound Energy's Energize Eastside Transmission project along Olympic Pipe Line's two petroleum pipelines crossing the City of Newcastle, for the City of Newcastle, WA, June 20, 2017.
57. Accufacts Review of the Draft Environmental Impact Statement for the Line 3 Pipeline Project Prepared for the Minnesota Department of Commerce, July 9, 2017, filed on behalf of Friends of the Headwaters, to Minnesota State Department of Commerce for Docket Nos. CN-14-916 & PPL-15-137.
58. Testimony of Richard B. Kuprewicz, president of Accufacts Inc., in the matter West Goshen Township and Concerned Citizens of West Goshen Township v. Sunoco Pipelines, L.P. before the Pennsylvania Public Utilities Commission, Docket No. C-2017-2589346, on July 18, 2017, on Behalf of West Goshen Township and Concerned Citizens of West Goshen Township.
59. Direct Testimony of Richard B. Kuprewicz, president of Accufacts Inc., on Behalf of Friends of the Headwaters regarding Enbridge Energy, Limited Partnership proposal to replace and reroute an existing Line 3 to the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (MPUC PL-9/CN-14-916 and MPUC PL-9/PPL-15-137), September 11, 2017 and October 23, 2017.
60. Direct Testimony of Richard B. Kuprewicz On Behalf of The District of Columbia Government, before the Public Service Commission of the District of Columbia, in the matter of the merger of AltaGas Ltd. and WGL Holdings, Inc., Formal Case No. 1142, September 29, 2017.
61. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2018 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated December 4, 2017.
62. Report to Hugh A. Donaghue, Esquire, Concord Township Solicitor, "Accufacts Comments on Adelphia Project Application to FERC (Docket No. CP18-46-000) as it might impact Concord Township," dated May 30, 2018.
63. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2019 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 20, 2018.
64. Report to West Goshen Township Manager, PA, "Accufacts report on the repurposing of an existing 12-inch Sunoco pipeline segment to interconnect with the Mariner East 2 and Mariner East 2X crossing West Goshen Township," dated November 8, 2018.
65. Report to West Whiteland Township Manager, PA, "Accufacts Observations on Possible Pennsylvania State Pipeline Safety Regulations," prepared by Richard B. Kuprewicz, dated March 22, 2019.
66. Accufacts Public Comments on the Proposed Joint Settlement, BI&E v. Sunoco Pipeline L.P. ("SPLP"), Docket No. C-2018-3006534 ("Proposed Settlement"), submitted on August 15, 2019 to the Pennsylvania Public Utility Commission on the behalf of West Goshen Township as an intervener.
67. Report to West Whiteland Township Manager, Ms. Mimi Gleason, "Accufacts Perspective on Two Questions from West Whiteland's Board of Supervisors on Proposed Changes to ME 2 and ME 2X Construction/Operational Activities within West Whiteland," dated September 5, 2019."

68. Report to West Goshen Township Manager, Mr. Casey LaLonde, "Accufacts Report on the episode on the evening of 8-5-19 at the Mariner East Boot Road Pump Station ("Event"), Boot Road, West Goshen Township, PA," dated September 16, 2019.
69. Provided direct testimony before the Arizona Corporation Commission, In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on Fair Value of the Properties of Southwest Gas Corporation Devoted to its Arizona Operations (Docket No. G-01551A-19-0055), testified on behalf of Utilities Division Arizona Corporation Commission, February 19, 2020.
70. Report to West Goshen Township Manager, Mr. Casey LaLonde, "Accufacts Report on the Mariner East 2X Pipeline Affecting West Goshen Township," dated July 23, 2020.
71. Assisted the Commonwealth of Massachusetts, Office of the Attorney General in developing pipeline safety processes to be incorporated into the settlement agreement related to Columbia Gas' sale of Assets to Eversource following the Merrimack Valley, Massachusetts overpressure event of September 13, 2018.
72. Report to Natural Resources Defense Council, Inc., "Accufacts' Observations on the Use of Keystone XL Pipeline Pipe Exhibiting External Coating Deterioration Issues from Long Term Storage Exposure to the Elements," October 1, 2020.
73. Report to Pennsylvania Public Utilities Commission ("PAPUC"), "Accufacts Comments on Proposed Pennsylvania Intrastate Liquid Pipeline Safety Regulations," dated October 29, 2021, prepared for West Whiteland Township Board of Supervisors, West Whiteland Township, PA. Filed to PAPUC public web docket November 5, 2021 by West Whiteland Township under Reference Docket Number L-2019-3010267. Addresses suggested improvements in proposed pipeline safety rules for PA intrastate liquid transmission pipelines.
74. Submitted written testimony of Richard B. Kuprewicz on Behalf of Bay Mills Indian Community to ALJ Dennis Mack, dated December 14, 2021, in the matter of the Application of Enbridge Energy, Limited Partnership for Authority to Replace and Relocate the Segment of Line 5 Crossing the Straits of Mackinac into a Tunnel Beneath the Straits of Mackinac, before the State of Michigan Public Service Commission, U-20763.
75. Public presentation to New York State Indian Point Nuclear Facility Decommissioning Oversight Board on Holtec removal activities in proximity to Enbridge three Natural Gas Transmission Pipelines, March 17, 2022.
76. Report to Pipeline Safety Trust and Bold Alliance, "Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.," March 23, 2022.
77. Accufacts Inc., Public Presentation for the National Academies of Science Engineering Medicine and The Transportation Research Board, "To Committee on Criteria for Installing Automatic and Remote-Controlled Shutoff Valves on Existing Gas and Hazardous Liquid Transmission Pipelines," 4/27/22.
78. Accufacts Inc, "6/13/22 Webinar to Illinois Emergency Responders, Healthcare Providers, & Local Officials on Responses to CO₂ Transmission Pipeline Releases," 6/13/22.
79. Accufacts Report for Pipeline Safety Trust, "Safety of Hydrogen Transportation by Gas Pipelines," 11/28/22.
80. Completed a series of testimonies related to Enbridge's Line 5 proposal to replace 2 – 20-inch diameter existing submerged pipelines currently lying across the bottom of the Straits of Mackinac with a 30-inch diameter grade X-70 pipeline, proposed to be installed in a 21-foot diameter concrete tunnel to be installed across the approximate 4-mile span of the Straits of Mackinac. Testified on Behalf of the Bay Mill Indian Community before the State of Michigan Public Service Commission, Docket U-20763, in opposition to this very poorly designed proposal/installation allowing for movement of the pipeline on rollers within the tunnel. Final testimony to the docket submitted May 19, 2023. This is the only pipeline proposal I am aware of in the world that would place a crude oil and liquid propane pipeline, especially a 30-inch diameter pipeline, within a tunnel.
81. Issued to Ms. Niroop Srivatsa, City Manager, "Accufacts Report for the City of Lafayette on the Status of the Tree Assessment Process with PG&E," indicating most of the trees identified for removal by PG&E risk management

approach have nothing to do with gas pipeline safety, June 15, 2023.

82. Issued Direct Testimony to Illinois Commerce Commission (“ICC”) on the Navigator Heartland Greenway LLC Application for a Carbon Dioxide Transportation and Sequestration pipeline, under Docket 23-0161, on behalf of Citizens Against Heartland Pipeline (“CAHGP”), McDonough County, Christian County and Hancock County (the “Counties”) (jointly, “Citizen and County Intervenor” of “CCI”), raising serious questions as to PHMSA’s recent assertions of pipeline safety jurisdiction, and underscoring the ICC’s authority for pipeline siting jurisdiction of said pipeline proposal in the State of Illinois, filed June 15, 2023. Applicant has terminated their application.
83. Issued Direct Testimony to Illinois Commerce Commission (“ICC”) on the WOLF Carbon Solutions US LLC Application for a Carbon Dioxide Transportation and Sequestration pipeline, under Docket 23-0475, for a certificate of authority to construct and operate a carbon dioxide pipeline and when necessary to take interest in property as provided by law of eminent domain, testifying on Behalf of Citizens Against Predatory Pipelines (“CAPP”): 1) identifying serious inadequacies in PHMSA’s pipeline safety regulations, 2) explaining why the Commission should require pipeline temperature profiles 3) detailing why DNV-RP-F104 is not relevant to this filing and 4) underscoring the ICC’s authority to require additional critical information from the Applicant in this matter, filed October 24, 2023. Applicant has withdrawn their submission to the Commission.
84. Provided general summary, main observations/concerns, on “Draft Environmental Impact Statement: Otter Tail to Wilkin Carbon Dioxide Pipeline Project” submitted to Minnesota Public Utilities Commission regarding Summit Carbon Solutions, LLC proposed 28 mile long 4-inch diameter CO₂ liquid transmission pipeline (“Otter Tail Pipeline”) within Minnesota, PUC Docket No. IP-7093/PPL-22-422, provided to Clean Up the River Environment (“CURE”) on 1/29/2024.
85. Issued to EarthJustice, “Observations concerning Kern County’s Draft Environmental Impact Report (“DEIR”) on the TerraVault I Carbon Capture and Storage Project (“Project”),” dated February 26, 2024, “Observations concerning Kern County’s Recent Recirculated Draft Environmental Impact Report (“RDEIR”) on the TerraVault I Carbon Capture and Storage Project (“Project”),” dated July 17, 2024, and “Evaluation of Kern County Response to Comments and Final Recirculated Environmental Impact Report on the TerraVault I Carbon Capture and Storage Project, dated October 15, 2024. The Project situated in Kern County is proposed by the California Resources Corporation to separate a portion of the pre-combustion Elk Hills field gas production, treat and inject via liquid transmission pipelines, CO₂ into two sequestration injection wells within the Elk Hill oil field. The reports identify many technical gaps in filings to Kern County.
86. Issued for the Tribal Partnerships Program, “Observations on the U.S. Army Corps of Engineers Draft Environmental Assessment, Clean Water Act Section 404(b)(1) Guidelines Evaluation, and Public Interest Review (collectively referenced as “DCDD”) for the Enbridge Line 5 Wisconsin Segment Relocation Project (“Project”), dated May 2024,” report dated July 31, 2024 affecting the Bad River Band of the Lake Superior Tribe of Chippewa Indians reservation.

Exhibit B

Accufacts Inc.

“Clear Knowledge in the Over Information Age”

***Evaluation of Las Flores Pipeline System Startup
Proposal***

Prepared For

**The Center for Biological Diversity
&
The Environmental Defense Center**

December 20, 2024

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I. Executive summary and major findings

Accufacts Inc. (“Accufacts”) was asked to review the documents related to the Las Flores Pipeline System (“Pipelines”) for possible restart. A Consent Decree signed in March, 2020 places responsibility for approving processes related to the onshore pipeline system restart on the California Office of the State Fire Marshal, or OSFM, the agency responsible for intrastate hazardous liquid pipeline safety.¹ The Consent Decree replaces various Corrective Action Orders issued on the Pipelines by the Pipeline and Hazardous Materials Safety Administration, or PHMSA, the federal agency responsible for pipeline safety.² PHMSA is the federal agency responsible for establishing minimum pipeline safety regulations for many pipelines operating in the U.S., including intrastate hazardous liquid transmission pipelines. States meeting certain conditions can impose pipeline safety standards for intrastate pipelines beyond PHMSA regulations as long as such state regulations are not in conflict with PHMSA regulations. By agreement, the Consent Decree gives the OSFM main pipeline safety approval authority of the Pipelines if the OSFM’s actions are not in conflict with PHMSA pipeline safety regulations, and if PHMSA decides the proposed waiver alternative measures “provide an equal or greater level of safety.”^{3, 4} The Consent Decree is inadequate, missing many corrosion threats to the Pipelines that can result in rupture.

Accufacts finds that the main technical issues concerning the restart of the Pipelines are:

- 1. The poorly designed pipeline system renders required federal mandated cathodic protection (“CP”), intended to help address pipeline external corrosion, ineffective.**
- 2. Current inline inspection (“ILI”) technologies cannot adequately allow the assessment of all forms of external corrosion threats that most likely exist on the Pipelines.**
- 3. The high operating temperatures needed to reduce the viscosity of the heavy crude oil significantly accelerate all forms of external pipeline corrosion that will not be mitigated by the ineffective CP system once the Pipelines go into operation.**
- 4. Segments at risk of corrosion related cracking (i.e., stress corrosion cracking or selective seam corrosion cracking) are at the highest risk of failure. The poorly designed Pipelines cannot be made as safe as new pipelines.**

¹ Such state responsibility is dependent on whether the state agency meets certain qualifications required by PHMSA and whether the state Legislature has granted such state authority, as California has.

² UNITED STATES DISTRICT COURT CENTRAL DISTRICT OF CALIFORNIA, UNITED STATES OF AMERICA, and the PEOPLE OF THE STATE OF CALIFORNIA, ex rel. DEPARTMENT OF FISH AND WILDLIFE, PEOPLE OF THE STATE OF CALIFORNIA, ex rel. CENTRAL COAST REGIONAL WATER QUALITY CONTROL BOARD, ex rel. CALIFORNIA DEPARTMENT OF PARKS AND RECREATION, ex rel. CALIFORNIA STATE LANDS COMMISSION, ex rel. CALIFORNIA DEPARTMENT OF FORESTRY AND FIRE PROTECTION’S OFFICE OF STATE FIRE MARCHALL, and THE REGENTS OF THE UNIVERSITY OF CALIFORNIA (Plaintiffs) v. PLAINS ALL AMERICAN PIPELINE L.P. and PLAINS PIPELINE, L.P. (Defendants), Consent Decree, Civil Action No. 2:20-cv-20415 signed March 2020 (“Consent Decree”).

³ *Ibid.*, Appendix B & Appendix D, paragraph 1.

⁴ PHMSA website, “Special Permits and State Waivers Overview,” at <https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-and-state-waivers-overview>.

Oil spills are catastrophic events, and operation of any pipeline carries a risk of spill. At best, good pipeline design and pipeline integrity management tools can reduce—but not eliminate—the risk. The Consent Decree is replacing incomplete integrity management (“IM”) approaches implemented by Plains that failed to prevent a pipeline rupture from the poor design of the Pipelines, with another incomplete IM approach expecting a change in the outcome.

The Pipelines have been sitting shut down for over nine years at ambient temperatures without effective CP protection. While external corrosion rates in this shutdown mode are significantly reduced because of lower temperatures as discussed later in this report, **the risk of external corrosion is not eliminated**. The Consent Decree requires the OSFM to seek a waiver of the federal pipeline safety CP requirements defined under Subpart H, subject to the approval of PHMSA, to permit the Pipelines to restart.^{5, 6} Complicating this matter is the incorporation of risk analysis by the state into the Consent Decree that is under the control of the pipeline operator and is not made fully public, but subject only to the “review and comment” of the OSFM. To be fair, the OSFM must meet certain state legislated risk analysis requirements that though well-meaning, are incomplete, such as, for example, how to define what a reasonable worst-case discharge is to prudently evaluate the risk of a pipeline failure.⁷ This is a problem I often see abused in federal pipeline oil spill response plans that doesn’t adequately capture pipeline rupture hydraulics.⁸ One of the major problems with risk analysis, a determination of the likelihood of an event occurring, and why it is not codified into federal pipeline safety regulations, is that such approaches are usually not complete or representative of the true risks of a specific pipeline operation. The impacts of any pipeline failure are significant and long-lasting, causing destruction of habitats, death of wildlife, and even human fatalities. It is impossible to predict a pipeline failure, and decision-making based on the perceived probability of failure does not adequately account for the severe consequences that will ensue, particularly if those decisions fail to capture pipeline rupture hydraulics. I call this “Space Shuttle Syndrome,” because, in the rush to launch the space shuttle program, NASA decisionmakers understated its true risks and dismissed well established safety culture protocols, resulting in the loss of two space shuttles and their crews and ending the space shuttle program.

The Consent Decree is placing undue responsibilities on the OSFM which might not appreciate the limits of current inline inspection technical capabilities. The Consent Decree overly relies on ILI technologies and their associated engineering critical assessments that are not capable of prudently addressing many forms of external corrosion, especially interactive forms such as Stress Corrosion Cracking, or SCC, whose time to failure is difficult, if not impossible, to predict as discussed later in this report. The current poorly designed Pipelines do not permit CP protection to mitigate external corrosion on the Pipelines that must operate at uniquely high temperatures. The required high temperatures accelerate all forms of external corrosion. New pipelines would incorporate proper design such as non-insulated pipe and newer forms of pipeline coating technology, that would permit CP to be effective in addressing external corrosion even at high temperatures to help assure pipeline safety. No pipeline waiver issued under the conditions addressed in the Consent Decree is consistent with pipeline safety nor can ensure the same level

⁵ 49CFR§195 Subpart H - Corrosion Control.

⁶ Consent Decree, Appendix B, “State Waivers for Line 901, 903,”.

⁷ CA Code CCR 19§2111 – Risk Analysis.

⁸ 49CFR§194 Response Plans for Onshore Oil Pipelines.

of safety as that associated with a prudently designed pipeline system. Neither Plains, the pipeline operator at the time of the May 19, 2015 failure, nor the new owner, Sable, designed or built the present Pipelines with their serious deficiencies, but as a pipeline operator Sable bears the ultimate responsibilities should the Pipelines fail.

II. Accufacts experience qualifying me as an expert in this matter.

Accufacts Inc. (“Accufacts”) was asked to review the Line 901/903 pipelines, now renamed Lines CA-324/CA-325 (“Pipelines”), and related documents such as those produced by the OSFM on their website. A Consent Decree places responsibility for approving processes related to the onshore pipeline system restart first on the OSFM, then on PHMSA.⁹ The Center for Biological Diversity and The Environmental Defense Center asked Accufacts to provide an independent evaluation of documents related to a possible restart of the Pipelines to safely move heavy oil production from offshore platforms in the Santa Barbara Channel into the Pipelines. It should be noted that the OSFM has recently issued a waiver on PHMSA’s CP obligations for the Pipelines. I have not seen the details related to OSFM’s decision on the granting of such a waiver.

I am a chemical engineer with over fifty years of experience in the energy industry, including over 25 years as president of Accufacts Inc. (“Accufacts”). Accufacts provides independent expert consulting services to assist decision makers in making informed decisions concerning pipelines. Pipeline safety expertise is provided in areas including, but not limited to: pipeline failure investigation, risk management/risk analysis, siting, construction, design, operation, maintenance, training, control room management including Supervisory Control and Data Acquisition (“SCADA”) approaches, leak/rupture detection, integrity management, emergency and spill response, and pipeline safety regulatory development and compliance. Much of my background is grounded in pipeline incident investigations following numerous pipeline rupture tragedies spanning several decades.

For the past two decades I have been involved as a representative of the public, which carries special obligations to avoid a conflict of interest, in advancing pipeline safety regulations at the federal and various state levels as demonstrated by my CV that is included as Attachment 1. For example, I played a significant role representing the public in developing integrity management federal pipeline safety regulations in the early 2000s for both liquid and gas transmission pipelines. These regulatory approaches emulated safety process approaches that I instituted and developed for the City of Bellingham, WA to assure that a ruptured pipeline there could be restarted and operated safely. This safety process approach, identified as the Pipeline Safety Immediate Action Plan, or PSIAP, identified steps that the pipeline operator was to complete following the Bellingham rupture tragedy of June 10, 1999, before that pipeline could be permitted to safely return to service. The PSIAP is a matter of public record compliments of Washington State’s Right-to-Know laws. PSIAP formed a template for the integrity management safety regulations developed by the Office of Pipeline Safety, which morphed into PHMSA in 2003.

⁹ Consent Decree, Appendix B & Appendix D.

For approximately fifteen years, through the development of federal standards for Transmission Integrity Management Programs (“TIMP”) for both liquid and gas integrity regulations, control room management (“CRM”), and Operator Qualification (“OQ”) rulemaking efforts, to cite a few pipeline safety rulemaking efforts, I served on the Technical Hazardous Liquid Pipeline Safety Standards Committee, also referred to as the Liquid Pipeline Advisory Committee, or LPAC, to advise PHMSA on possible pipeline safety regulation advancement. After a brief hiatus of several years, I have recently been reappointed by the Secretary of Transportation to represent the public again on LPAC, which carries numerous obligations to avoid a conflict of interest. I believe I am more than qualified to comment as an expert on the various issues related to CA-324/CA-325 pipeline system possible restart.

III. A brief historical perspective

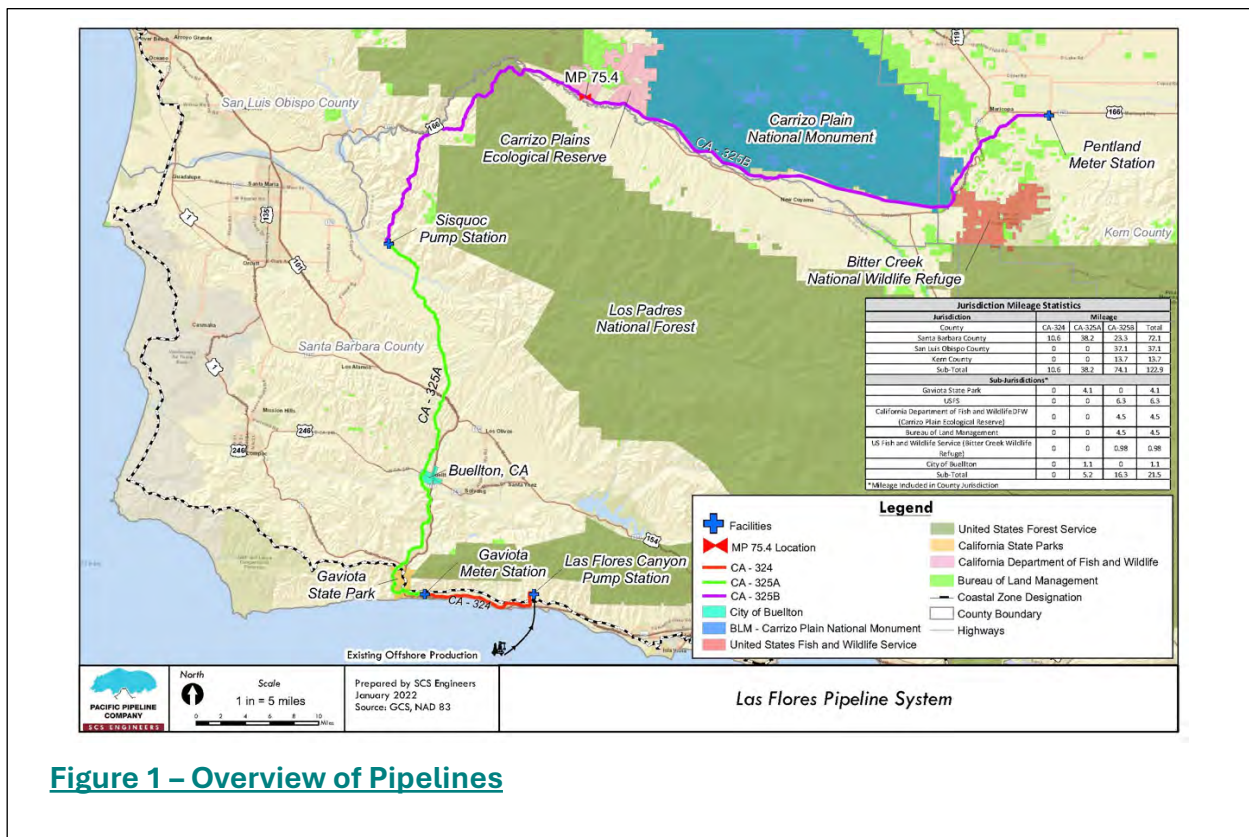


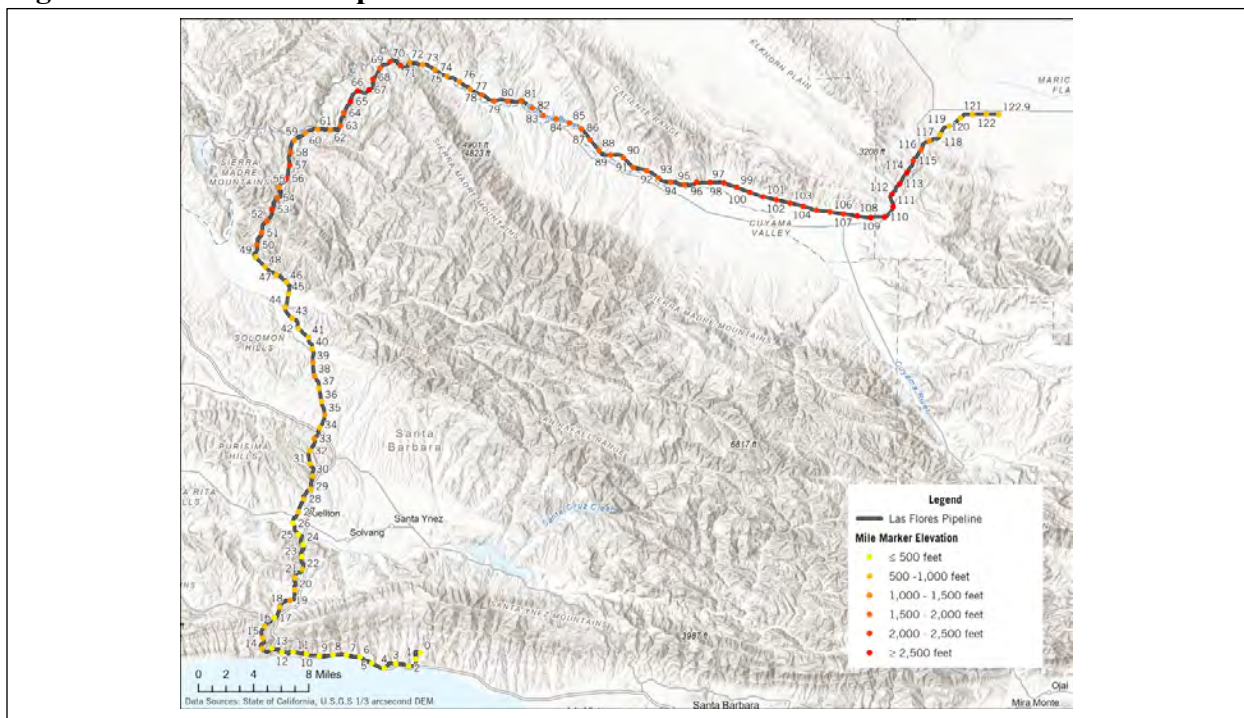
Figure 1 – Overview of Pipelines

Since the May 19, 2015 onshore pipeline rupture and oil release that spilled into the Santa Barbara Channel and beyond, the pipeline system known at the time as Lines 901/903, and offshore oil platforms feeding this system have been shut down. Lines 901/903 have recently been renumbered CA-324 and CA-325, respectively. These pipelines, which were classified as interstate pipelines at the time of the release, were ordered to be shut down and oil purged from the Pipelines and placed under nitrogen atmospheres under Corrective Action Orders instituted by PHMSA. Line 901 experienced an onshore pipeline rupture failure caused by massive external corrosion and released on the late morning of May 19, 2015 near Refugio State Beach that placed a considerable amount of oil into the sensitive waters of the Santa Barbara Channel and beyond. While the years since 2015 involved discussions for possible construction of new pipelines to replace the poorly

designed Lines 901/903, recent activities shifting ownership of the pipelines and associated infrastructure to Sable Offshore Corp. (“Sable”), are now focused on restarting the existing pipelines under new ownership and conditions stated under a Consent Decree.

The May 19, 2015 Line 901 rupture failure occurred at approximately 4 miles (MP 4) downstream of the Las Flores Canyon Pump Station due to extensive external corrosion. The Line 901 ruptured at approximately 56 % of the maximum operating pressure (“MOP”) of 1341 pounds per square inch gauge (“psig”) (which is 72 % specified minimum yield strength (“SMYS”)).¹⁰ In addition, further metallurgical forensic reports attached to the PHMSA Final Report, indicate that pipeline ruptured at a pressure of 737 psig, which was 39.6% of SMYS.¹¹ This pipeline failed at very low stress levels, not a surprise given that the depth of the corrosion failure was 89% of the measured wall thickness, and the ILI tools significantly mis indicated the size of the corrosion threats.¹²

Figure 2 – Overview of Pipelines route with MPs estimated



IV. The Las Flores Pipeline System.

The following is based on information readily in the public domain, as demonstrated by the footnote references. Because of many variations in MP numbers in various documents, MP numbers referenced in this report should be considered approximate with slight variations that don’t really impact my findings/conclusions/recommendations.

¹⁰ U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, “Failure Investigation Report, Plains Pipeline, LP, Line 901 Crude Oil Release, May 19, 2015 Santa Barbara County, California,” May 2016. p.14 of 23.

¹¹ DNV-G Final Report, “Line 901 Release (5/15/15) Mechanical and Metallurgical Testing, - Report No: OAPUS309DNOR (PP136049),” September 18, 2015, p. iii.

¹² *Ibid.*, “Summary of Observations,” p. vi.

The Pipelines, formerly identified as Line 901/903 operated by Plains (aka Plains All American Pipeline L.P. and Plains Pipeline L.P.), represent a pipeline system of approximately 125 miles in length running from the Las Flores Canyon Pump Station (milepost 0) to the Pentland Metering (and Storage) facility (at Milepost 125.3). Figure 1 is a general overview of the Pipelines routing. CA-224 (old Line 901) that runs from the Las Flores Canyon Pump Station (Milepost 0) to the Gaviota Meter Station (Milepost 10.7). Note that I have reversed the Milepost reported in PHMSA's Final Report to follow more conventional milepost numbering, increasing from the pipeline inlet at the Las Flores Canyon Pump Station (MP 0), to the pipeline outlet of the 24-inch diameter Line 901/CA-224 pipeline, the Gaviota Metering Station (MP 10.7). CA-324 is the sole feed into the 30-inch pipeline, CA-325A. CA-325A runs from the Gaviota Metering Station to the Sisquoc pump station (MP 49.2). CA-325B, also a 30-inch diameter pipeline, runs from the Sisquoc pump station (MP 49.2) to the Pentland metering station (~MP 125.3). Figure 2 shows the general route adding approximate MP numbers following this similar MP increasing numbering all the way to Pentland.

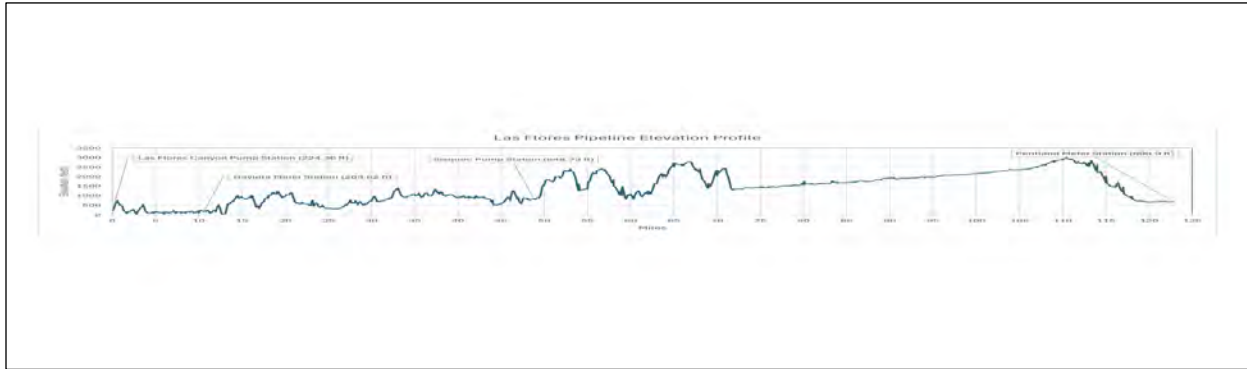
According to the PHMSA Final Report on the 2015 rupture:

Plains transports crude oil produced in federal and state waters off the coast of Santa Barbara, CA to inland refineries. Plains' pipeline is composed of two major pipeline sections: (1) Line 901, and (2) Line 903. Lines 901 and 903 were constructed in the late 1980s, hydrostatically tested in 1990, and went into crude oil service in 1992 and 1991, respectively. The pipelines are coated with coal tar urethane and covered with foam insulation which in turn is covered by a tape wrap over the insulation. Shrink wrap sleeves, which provide a barrier between the steel pipeline and soil for corrosion prevention, are present at all of the pipeline joints on Line 901 and multiple locations on Line 903. The pipelines carry high viscosity crude oil at a temperature of approximately 135 degrees Fahrenheit to facilitate transport. Lines 901 and 903 are controlled from the Plains Control Room's (PCR) California console in Midland, TX.

Line 901 is a 24-inch diameter pipeline that extends approximately 10.7 miles in length from the Las Flores Pump Station to the Gaviota Pump Station; and (2) Line 903 is a 30-inch diameter pipeline that extends approximately 128 miles in length from the Gaviota Pump Station to the Emidio Pump Station, with intermediate stations at Sisquoc Mile Post (MP) 38.5 and Pentland (MP 114.57). There is a delivery point into Line 901 from Venoco's Line 96 located approximately 2 miles downstream of the Las Flores Station. All of Line 901 crude oil throughput enters Line 903. Line 901 was manufactured of low carbon steel by Nippon Steel in Japan in 1986. Line 901's pipe specifications are API 5L, Grade X-65 pipe, 0.344-inch wall thickness, with a high frequency-electric resistance welded (HF-ERW) long seam. The line was hydrotested to 1,686 pounds per square inch gauge (psig) on November 25, 1990. There are additional crude oil lines coming in and out of Pentland Station with numerous tanks at that station used to blend different crude oils for delivery further downstream. At Emidio Station crude oil is delivered to above-

ground storage tanks for future delivery to Los Angeles refineries in a separate pipeline system.¹³

Figure 3 - Approximate Elevation Profile - Las Flores Canyon Pump Station (MP 0) to Pentland Station (MP ~125.3)



PHMSA provided additional information related to Line 903:

(2) Line 903 is a 30-inch diameter pipeline that extends approximately 128 miles in length from the Gaviota Pump station to the Emidio Pump Station, with intermediate stations at Sisquoc Mile Post (MP) 38.5 and Pentland (MP 114.57).¹⁴

Plains has informed PHMSA that Line 903 has insulation and shrink wrap sleeves on the girth welds similar to the Affected Pipeline {Line 901}.¹⁵

It is not clear from the documents produced if Line 903 insulation is also tape wrapped like Line 901, that would further shield the CP system from the Pipelines, assuring that CP is ineffective.

Figure 3 is an approximate elevation profile (approximate elevation of pipeline in feet versus pipeline milepost) for the Las Flores Pipeline System developed by the Center for Biological Diversity's Geographic Information System, or GIS, specialist using information readily available in the public domain. Pipeline elevation profiles play a critical role in understanding liquid transmission pipeline operation and risks, such as evaluating ILI runs, valve placement/actuator decisions, emergency and oil spill actions, and spill response planning. In addition, if a pipeline hydraulic profile, also referred to as a hydraulic gradient, is superimposed on an elevation profile, much information about pipeline risk can be gained. A hydraulic gradient is required of the pipeline operator under California Risk Analysis regulation.¹⁶ A pipeline hydraulic gradient includes a plot of operating pressure versus milepost for a specified crude oil gravity and flow rate, but for this unique system, a crude oil viscosity and temperature should also be included on the

¹³ U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, "Failure Investigation Report, Plains Pipeline, LP, Line 901 Crude Oil Release, May 19, 2015 Santa Barbara County, California," May 2016, pp. 4 & 5 of 21.

¹⁴ *Ibid.*, p. 4 of 21.

¹⁵ PHMSA – In the Matter of Plains Pipeline, LP, Respondent, "Amendment No. 1 to the Corrective Action Order – CPF No. 5-2015-5011H," p. 2.

¹⁶ CA Code CCR 19§2111 – Risk Analysis (2) Pipeline Description (A).

hydraulic gradient as these parameters seriously impact the hydraulic gradient evaluation. Such hydraulic gradient information is important in evaluating the risks of a pipeline restart program, especially on the Pipelines given their highly unique elevation profile among other factors (See Figure 3). This information is probably not likely to be made public, though a competent experienced engineer can develop an approximate hydraulic profile for a pipeline system if they understand certain crude oil blended properties and temperatures.

V. TIMP regulations are not working to protect the public or the environment.

In the passage of the federal pipeline safety regulations setting standards for Transmission Integrity Management Programs, or TIMP, first for liquid, then gas, in 2002 and 2003, respectively, the use of performance-based approaches versus more prescriptive based regulations were agreed to as a compromise to advance important needed pipeline safety regulation in this area. Until the passage of TIMP regulations, pipeline operators were under no obligation to periodically assess the condition of their mainline pipelines. Performance-based regulation, in theory, allows a pipeline operator to choose between various alternatives that may work best for their pipeline. Prescriptive-based pipeline safety regulations historically have been imposed in federal pipeline safety regulatory efforts. Prescriptive regulations impose certain conditions that pipeline operators must, or shall, follow.

TIMP efforts for liquid pipelines define four basic approaches permitted in pipeline integrity assessment, depending on the pipeline threat that a pipeline segment might experience. Briefly, the major assessment methods most appropriate for this pipeline system are hydrostatic pressure testing (“hydrotesting”) and inline inspection (“ILI”) also known as smart pigging. As the Line 901 onshore oil release that flowed into sensitive waterway areas has clearly demonstrated, TIMP regulation is not working for many pipeline operators, even after the operator had run multiple ILI corrosion tool runs which I will expand on further below. Another unexpected outcome of TIMP performance-based regulation is that such less than clear regulation efforts are harder to enforce.

It’s important to note that pipeline integrity management tools are not a substitute for proper pipeline design or effective cathodic protections. Their purpose is simply to monitor the condition of pipelines over time and identify threats to the pipeline’s integrity.

1) Hydrotesting assessments.

Properly performed hydrotesting can be an important pipeline integrity assessment tool that proves a pipeline’s fitness for service to safely operate at MOP at the time of the hydrotest. Hydrotesting involves shutting down a pipeline and filling a pipeline segment with water. Proof of pipeline integrity or fitness for service testing is verified by carefully increasing water pressure with a water injection pump after air has been removed and the pipeline segment temperature stabilized. While federal pipeline safety regulations for liquid transmission pipelines define a “Subpart E” hydrotest to establish or verify maximum operating pressure, or MOP, a term having specific meaning in regulation, the regulations are not specific on important parameters to ensure a quality hydrotest that doesn’t damage the pipe. Minimum hydrotest pressures are established to verify the MOP at the time of the hydrotest, with

sufficient pressure safety margin at the time of the hydrotest. A Subpart E hydrotest is a proof for fitness test that the pipeline, at the time of the test, can withstand pressures above the MOP with a certain margin of pressure safety.¹⁷

One important caveat is needed regarding Subpart E hydrotests, which are often called strength tests. For a pipeline experiencing certain cracking threats such as selective seam cracking (SSC) or stress corrosion cracking (SCC)—corrosion threats that likely exist along the Las Flores Pipeline System—**a subpart E hydrotest is inadequate**. Current ILI technology cannot reliably identify if such cracking threats are present. More importantly, nor can associated engineering critical assessments provide prudent evaluation of such threats due to the inability to reliably predict corrosion colonies that can interact or link together in unpredictable ways. SCC colonies can be associated with disbanded coatings such as that occurring on the Pipelines where CP current is prevented from reaching the outer pipewall steel. A much higher pressure (higher % Specified Minimum Yield Strength, or SMYS) hydrotest is warranted. A prudent risk analysis should clearly demonstrate if such external corrosion cracking threats from environmental factors are possible around the Pipelines. **I need to note that it is not clear whether hydrotesting, if performed, will be a Subpart E test or a higher % SMYS hydrotest intended to address cracking threats such as SCC.** The Consent Decree strangely makes no mention of corrosion cracking threats or hydrotesting.

While considerable discussion in the Consent Decree has focused on the use of ILI to identify possible general wall loss corrosion threats well before failure, this agreement makes no mention of other forms of corrosion related threats such as corrosion cracking SCC or SSC. These forms of corrosion cracking are very challenging to identify via ILI, and more importantly, engineering critical assessments associated with ILI to predict time to failure can be highly unreliable, given the inactive threat nature of these type of corrosion cracking threats. The corrosion cracking threats tend to fail as pipeline ruptures. It is important that the cracking threat potentials on the Pipelines be prudently addressed and proposed solution be made public and transparent.

For pipeline segments that undergo large elevation changes, like the Line 325A/B segments, the pipeline must be cut up into segments to assure hydrotesting pressure ranges do not permanently deform the pipe. Hydrotesting can be more expensive than other pipeline integrity assessments such as ILI, but there are no built-in assumptions about the quality and thoroughness of the assessment that can be mismanaged such as that which can and often does occur with ILI approaches resulting in numerous pipeline ruptures after ILI assessments, as the May 19, 2015 release has clearly demonstrated. Hydrotesting is much more reliable than other pipeline integrity assessment approaches, such as ILI, at verifying a pipeline's fitness for service at the time of the test. Hydrotesting is usually performed by contractor firms experienced and qualified to perform a proper hydrotest for specific types of threats. The Consent Decree requires certain threshold general corrosion threats if identified by ILI be remediated before restart.¹⁸

¹⁷ 49CFR§195.304 Test pressure

¹⁸ Consent Decree, Appendix B (4) Integrity Management.

Hydrotesting is warranted, justified, and vastly appropriate for the Pipelines which have been sitting for over nine years without effective CP. I also need to mention that the use of nitrogen gas to idle the pipeline was meant to avoid internal corrosion attack and plays no role in preventing external corrosion attacks to keep the Pipelines in a “corrosion-free state” as mentioned by Steve Rusch, Sable’s vice president of environmental and regulatory affairs.¹⁹ The external corrosion sites experience reduced corrosion rates from the lower ambient soil temperatures as no hot oil was passing through the system, but the corrosion sites are not inactive, especially if CP systems are ineffective, such as on the Pipelines.

2) ILI assessments.

In the U.S., ILI or smart pig tool efforts started to develop in the early 1980s depending on the threat a pipeline operator was trying to address. ILI tools are usually multi-ton devices run inside a pipeline while the pipeline is operating to ascertain the condition of the pipeline depending on the type of threats trying to be analyzed. Given the advancements in technology including shrinking the equipment, ultrasonic, or UT, approaches that focus on direct anomaly measurement has historically proven superior for general wall thinning corrosion evaluation to approaches using inferred software-based algorithms, such as magnetic flux leakage (“MFL”) testing. Some ILI tools are more suitable than others depending on the threat. There is a wide spectrum of ILI tools and different technological approaches to select from depending on the type of threat trying to be reviewed. Operators don’t always select the ILI technology best suited to help identify threats on their system. Even with the advances in tool development and approaches there can still be a wide variation as to whether a specific ILI tool or vendor can properly identify a specific pipe threat and permit it to be further properly characterized after an ILI run. This is why pipeline operators will incorporate ILI tool tolerances and perform field verification digs to produce “unity plots” for a specific ILI run, to verify ILI vendor claims about their technology and its specific performance. This field verification data was not shared by Plains with the ILI vendor, a serious deficiency in ILI utilization. It is worth noting the PHMSA made it a point in their Failure Analysis of the Line 901 release, that the pipeline operator had not provided field dig verification feedback to the ILI vendor to confirm ILI capability.²⁰ For example, corrosion attacks can take on many forms such as general pipewall thinning (usually the easiest to determine depending on the ILI technology), various forms of corrosion cracking such as stress corrosion cracking (“SCC”), selective seam corrosion cracking (“SSC”), and pit corrosion. All such corrosion threats can lead to a pipeline failure and release. Based on my experience involving investigations of liquid transmission pipeline ruptures from SCC and SSC after ILI runs, some segments of the Pipelines exhibit the potential for SCC or SSC. Such external corrosion cracking threats are often found on pipelines with disbanded coating that are exposed to corrosion environments such as that introduced by the Pipeline’s insulation. It is incumbent on the new Pipeline operator, Sable, to demonstrate to the OSFM, and to the public and various regulatory agencies that SCC/SSC external cracking environments do not exist.

¹⁹ Los Angeles Times article by Tony Briscoe, “*Plan to restart pipeline sparks anger*,” Front page, October 20, 2024.

²⁰ U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, “Failure Investigation Report, Plains Pipeline, LP, Line 901 Crude Oil Release, May 19, 2015 Santa Barbara County, California,” May 2016. p.13 of 21.

Some forms of ILI technology to identify certain pipeline threats, if properly managed, can be superior to hydrotesting as they may identify some threats well before they go to failure. As too clearly demonstrated, however, in the May 19, 2015 Line 901 rupture, ILI cannot address all forms of external corrosion threat that are likely to exist on the Pipelines because of their poor design, their unique high temperature operation, and ineffectiveness of CP. If a corrosion ILI tool can be utilized within the limits of the pig vendor specification (i.e., such as maintaining pig speed within the operating pipeline), and if the ILI tool run is independently field verified, some ILI tools can be a superior form of assessment for many types of pipeline threats, such as general internal and external corrosion (i.e. wall-thinning) if prudently managed. The more specialized forms of corrosion, cracking and pitting, or corrosion within dents, however, can be much more challenging as ILI tools and their related engineering critical assessments still have technical limits. ILI tool vendors place specific limitations on their various tools, and it is important that the pipeline operator follow such restrictions that can easily invalidate an ILI tool run reading or result. ILI runs in hilly terrain, such as that which exist with the Pipelines (See Figure 3) can be quite challenging for ILI tools that can easily exceed multiple tons in weight as gravity never shuts off.

In investigating numerous pipeline rupture failures after ILI tool runs, I consistently see failures on the part of the pipeline operators to perform sufficient field verification digs to determine if bias is being introduced in a specific ILI tool approach on a specific pipeline segment, for a specific pipeline threat, and that the ILI tool selected is really appropriate to identify certain pipeline threats. Some pipeline operators repeatedly fail to recognize or even consider ILI tool capabilities and tolerances, especially as ILI vendors and pipeline engineers have tried to improve technologies and assessment techniques. It is worth noting that no one markets ILI tools claiming they don't work. An important consideration in integrity management approaches is whether the right ILI technology has been selected and is being prudently utilized by the pipeline operator. It is further worth noting that while running an ILI tool is not inexpensive, the cost of running such a tool is relatively less expensive compared to the overall quality of the field integrity verification program to assure the ILI tool is doing its job for a specific type of pipeline threat, on a specific pipeline segment.

Part of the problem is that many forms of interactive external corrosion pipeline cracking threats cannot be accurately characterized to allow meaningful engineering critical assessments that are reliable. Such assumptions or inability to properly engineer and predict interactive threats introduce significant margins of error to fitness for service predictions using ILI assessments. Just doing ILI reassessments when they really aren't capable of dealing with interactive corrosion threats is an illusion of safety. Basically, performing an inappropriate ILI assessment more often is not the solution as further explained below.

VI. The greatest threat on the Las Flores Pipeline System is from external corrosion.

It should not take a pipeline failure to identify that the greatest pipeline integrity threat on the Pipelines is from various forms of external corrosion due to poor design of these Pipelines rendering CP systems ineffective at reducing or preventing external corrosion failure.

The PHMSA Final Report stated:

Proximate or Direct Cause

PHMSA determined that the proximate or direct cause of the release was progressive external corrosion of the insulated 24-inch diameter steel pipeline. The corrosion occurred under the pipeline's coating system, which consisted of a urethane coal tar coating applied directly to the bare pipe, covered by foam thermal insulation with an overlying Polyken tape wrap. Water has been noted in the foam insulation at a number of digs, indicating that the integrity of the coating system had been compromised. The external corrosion was facilitated by the environment's wet/dry cycling, as determined by the PHMSA-approved, third-party metallurgical laboratory. The release was a single event caused at an area where external corrosion had thinned the pipeline wall. There is no evidence that the pipeline leaked before the rupture. There was a telltale "fish mouth" (a split due to over-pressurization) at the release site indicating the line failed in a single event.²¹

PHMSA goes on to list numerous contributory causes, among them a significant observation, "Corrosion under insulation (CUI) cannot be prevented on insulated lines where the coating system has been compromised."²² This important fact should also play a major role into any decision to restart the Las Flores Pipeline System as explained in further detail in this report. This critically important PHMSA observation should not come as a surprise to any pipeline operator. Bottom line, Plains acquired a poorly designed set of Pipelines in the early 1990s that rendered the CP system ineffective at preventing or mitigating external corrosion on a pipeline system operating at high temperatures. Some years after acquiring the Pipelines and after TAMP regulations were promulgated in late 2002, Plains did not implement an appropriate integrity management program to prevent the pipeline failure from external corrosion attack. The question now is whether Sable's compliance with the Consent Decree under the approval of the OSFM relying on the capabilities of ILI tools can prevent another failure on the Pipelines? **Clearly, current ILI technology does not meet an obligation to reliably identify all forms of external corrosion most likely present on much of the Pipelines.** The CP systems required by PHMSA regulations will not be effective on most of the pipeline mileage in the Las Flores Pipeline System as previously discussed, and from my perspective there is serious doubt as to whether these poorly designed pipelines can be made as safe as new pipelines that have properly functioning cathodic protections.

Regarding the Las Flores Pipeline restart decision and related integrity assessments, it is important to understand how CP systems are supposed to work. In layman's terms, a CP system impresses a weak current into a pipeline turning the pipeline into a cathode in an electrochemical corrosion cell on the outside of a buried pipeline, to control or reduce external corrosion. Older nonconducting pipeline coatings such as that which exists on the Pipelines do not allow for CP current to pass through them. The purpose of the CP system is thus to introduce current to the outer pipewall where the older coatings have been penetrated, such as with holes or tears in the outer coating. Unfortunately, older pipeline external coatings such as the urethane coal tar outer coatings, like those on the Pipelines, are also well known to not adhere tightly to a pipeline over time, causing coating separation or disbondment. Such disbondment can result in external

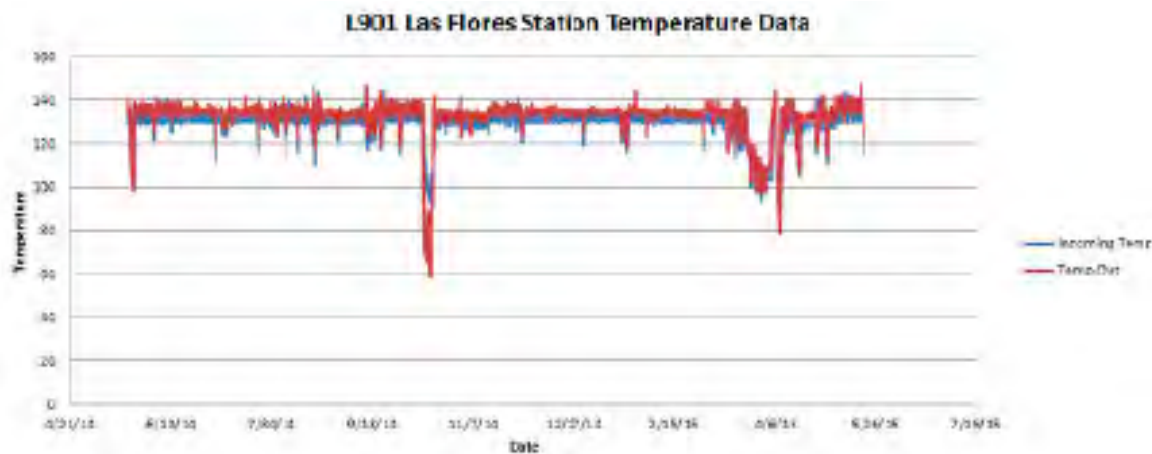
²¹ *Ibid*, p. 14 of 21.

²² *Ibid*, p. 14 of 21.

pipewall corrosion cells under the coating, generating many different forms of corrosion, especially SCC and SSC cracking in the wrong environments, that are not protected by CP. To add to this threat of external corrosion, the Las Flores Pipeline System’s external insulation traps and serves as a water conduit further increasing external corrosion as a water fed corrosion attack. And lastly, the Polyken tape wrap installed during pipeline installation around the outside of the insulation is also well known to not be conductive, further shielding and preventing CP current from reaching the outer pipe wall. **This is a perfect storm or combination of factors all working to render CP ineffective.** Without effective cathodic protections, the pipeline is at particularly high risk of spilling again. To further underscore the lack of a proper integrity management program, this pipeline operates at elevated temperature that accelerates external corrosion as explained further below. New types of pipeline coatings now allow the passage of CP current through such coating to mitigate external corrosion even if the coating disbonds from the pipeline.

VII. High pipeline operating temperatures accelerate all forms of corrosion.

Figure 4 Los Flores Temperature Data from DNV Line 901 Release (5/19/15) Technical Root Cause Analysis included in PHMSA Final Report.²³



If one is experienced in handling/refining the heavy crude oils produced offshore that feed into the Las Flores Pipeline System, this crude oil not only needs to be diluted with natural gas liquids, or NGLs, but the pipeline must be operated at high pipeline temperatures, approximately 135 °F, that also is required to reduce the blended oil viscosity to get the fluid over the main hill beyond the Sisquoc Pump Station to Pentland. While the PHMSA Final Report mentions 135 °F as a pipeline operating temperature, Figure 4 represents a temperature graph indicating 135 °F was not unusual, but higher fluid temperature to improve the flow and capacity of the Pipelines did occur.

Chemical engineers experienced in reaction kinetics are familiar with the Arrhenius equation which indicates that chemical reaction rates, such as that for corrosion, essentially double for every 10 °C (18 °F) increase in temperature. This means that the rate of corrosion at 140 °F is about 32

²³ *Ibid.*, “Figure 23, L901 Las Flores Station Temperature Data,” p. 375 of 510.

times that for a pipeline operating at 60 °F, a typical ambient soil condition. Because of the higher viscosity of unblended offshore oil there probably is little opportunity to reduce the Las Flores Pipeline System temperature to help reduce corrosion rates on a pipeline system where the CP system is ineffective. If the Pipelines are returned to operation, all forms of external corrosion will remain a primary threat of concern for pipeline failure.

VIII. The Consent Decree agreement fails to require adequate IM processes to prevent another rupture of the poorly designed Pipelines.

It is important to understand that the Consent Decree is just a compromise agreement between the signature parties and may be missing important technical matters related to the Pipelines. I find it odd that many of the technical issues discussed above were not identified or addressed in the Consent Decree. External corrosion cracking risk was well known for many decades to be a threat of concern for pipelines exhibiting disbanded external coating where CP systems are ineffective.

I find it especially strange that Plains the pipeline operator at the time of the Line 901 rupture got itself into serious trouble by failing to understand that the poor design of the Pipelines could not be adequately addressed by ILI. It appears that the Consent Decree continues to foster the illusion that ILI can adequately permit assessment of corrosion risks, especially cracking threats most likely to exist on major segments of the Pipelines (see Figure 3, for example). The Consent Decree doesn't even mention corrosion cracking threats for this system operating at high temperature that exacerbates all forms of external corrosion as previously discussed.

And lastly, I would caution that the Consent Decree gives authority to the OSFM on certain pipeline safety related decisions. These OSFM decisions, however, cannot violate federal pipeline safety regulations and that I believe require a public decision process for PHMSA approval to assure any waiver meets or exceeds the level of safety had the waiver not been requested.

IX. The poorly designed Pipelines cannot be made as safe as new pipelines.

Sable's website implies that the Pipelines will be repaired, stating "PPC undertook a comprehensive repair and maintenance program to restore the pipeline to "as-new" condition."²⁴ As referenced in footnote 19 above, this isn't the only time that a Sable representative has suggested the Pipelines will be restored to "as-new" condition or a "corrosion free" state. A new pipeline would be properly designed such that the federal pipeline safety regulations requiring a CP system would be effective and do its job, while allowing CP monitoring to assure the new pipelines were adequately protected from external corrosion attack by an effective CP design. A new pipeline would not be trying to utilize CP on a pipeline improperly coated, that seriously disbonds from the pipe, with a system insulated to assist in water reaching the outer pipe steel, while operating at higher temperature. All these poor design factors accelerate all forms of external corrosion including cracking. It is a misguided illusion that relying on ILI can attempt to stay ahead of pipeline failure on such a poorly designed system. A cursory review of the PHMSA Final

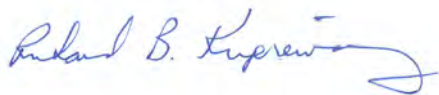
²⁴ See Sable's website concerning, "Sable Offshore Corp. Provides Update on Pacific Pipeline Company Operations," October 28, 2024, at: <https://www.sableoffshore.com/news/news-details/2024/Sable-Offshore-Corp.-Provides-Update-on-Pacific-Pipeline-Company-Operations/default.aspx>.

Report, Appendix G In-Line Inspection report will indicate that even running ILI tools, it is impossible to return Line 901 to an “as new” condition given the numerous corrosion anomalies.²⁵ The idea that running ILI tools should be sufficient to assure an “as-new” pipeline condition and safe operation of these poorly designed Pipelines with ineffective CP protection is a false premise, as the Pipelines are far from being in a new condition, with numerous anomalies, given their poor design approach and operating history.

X. Conclusion.

Given the ineffectiveness of the CP system to protect against external corrosion and the fact that the Pipelines have sat for over nine years without effective CP, and the failure of the Consent Decree to address these possible threats via proper hydrotesting and ILI, it is imprudent to expect that such limited assessment techniques can adequately protect against corrosion failure. Poor pipeline design and using the wrong set of integrity management tools (i.e., tools that do not adequately detect and permit the prudent evaluation of the type of corrosion threats specific to a given pipeline) can make the risk of an oil spill orders of magnitude worse. The Las Flores Pipeline System is unusually dangerous given its age and inherent design flaws.

The above represents my opinions based on experience with too many pipeline rupture investigations. I reserve the right to update this report if more relevant information is made available.



Richard B. Kuprewicz
President
Accufacts Inc.

²⁵ U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, “Failure Investigation Report, Plains Pipeline, LP, Line 901 Crude Oil Release, May 19, 2015 Santa Barbara Country, California, - Appendix G In-Line Inspection Report by Lamontagne for the Oak Ridge National Laboratory” May 2016, pp. 44 – 138 of 510.

Curriculum Vitae.

Richard B. Kuprewicz

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Profile:

As president of Accufacts Inc., I specialize in gas and liquid pipeline investigation, auditing, risk management, siting, construction, design, operation, maintenance, training, SCADA, leak detection, management review, emergency response, and regulatory development and compliance. I have consulted for various local, state and federal agencies, NGOs, the public, and pipeline industry members on pipeline regulation, operation and design, with particular emphasis on operation in unusually sensitive areas of high population density or environmental sensitivity.

Employment:

Accufacts Inc.

1999 – Present

Pipeline regulatory advisor, incident investigator, and expert witness on all matters related to gas and liquid pipeline siting, design, operation, maintenance, risk analysis, and management.

Position: President
Duties: > Full business responsibility
> Technical Expert

Alaska Anvil Inc.

1993 – 1999

Engineering, procurement, and construction (EPC) oversight for various clients on oil production facilities, refining, and transportation pipeline design/operations in Alaska.

Position: Process Team Leader
Duties: > Led process engineers group
> Review process designs
> Perform hazard analysis
> HAZOP Team leader
> Assure regulatory compliance in pipeline and process safety management

ARCO Transportation Alaska, Inc.

1991 - 1993

Oversight of Trans Alaska Pipeline System (TAPS) and other Alaska pipeline assets for Arco after the Exxon Valdez event.

Position: Senior Technical Advisor
Duties: > Access to all Alaska operations with partial Arco ownership
> Review, analysis of major Alaska pipeline projects

ARCO Transportation Co.

1989 – 1991

Responsible for strategic planning, design, government interface, and construction of new gas pipeline projects, as well as gas pipeline acquisition/conversions.

Position: Manager Gas Pipeline Projects
Duties: > Project management
> Oil pipeline conversion to gas transmission
> New distribution pipeline installation
> Full turnkey responsibility for new gas transmission pipeline, including FERC filing

Four Corners Pipeline Co.

1985 – 1989

Managed operations of crude oil and product pipelines/terminals/berths/tank farms operating in western U.S., including regulatory compliance, emergency and spill response, and telecommunications and SCADA organizations supporting operations.

- Position:** Vice President and Manager of Operations
Duties:
- > Full operational responsibility
 - > Major ship berth operations
 - > New acquisitions
 - > Several thousand miles of common carrier and private pipelines

Arco Product CQC Kiln

1985

Operations manager of new plant acquisition, including major cogeneration power generation, with full profit center responsibility.

- Position:** Plant Manager
Duties:
- > Team building of new facility that had been failing
 - > Plant design modifications and troubleshooting
 - > Setting expense and capital budgets, including key gas supply negotiations
 - > Modification of steam plant, power generation, and environmental controls

Arco Products Co.

1981 - 1985

Operated Refined Product Blending, Storage and Handling Tank Farms, as well as Utility and Waste Water Treatment Operations for the third largest refinery on the west coast.

- Position:** Operations Manager of Process Services
Duties:
- > Modernize refinery utilities and storage/blending operations
 - > Develop hydrocarbon product blends, including RFGs
 - > Modification of steam plants, power generation, and environmental controls
 - > Coordinate new major cogeneration installation, 400 MW plus

Arco Products Co.

1977 - 1981

Coordinated short and long-range operational and capital planning, and major expansion for two west coast refineries.

- Position:** Manager of Refinery Planning and Evaluation
Duties:
- > Establish monthly refinery volumetric plans
 - > Develop 5-year refinery long range plans
 - > Perform economic analysis for refinery enhancements
 - > Issue authorization for capital/expense major expenditures

Arco Products Co.

1973 - 1977

Operating Supervisor and Process Engineer for various major refinery complexes.

- Position:** Operations Supervisor/Process Engineer
Duties:
- > FCC Complex Supervisor
 - > Hydrocracker Complex Supervisor
 - > Process engineer throughout major integrated refinery improving process yield and energy efficiency

Qualifications:

Served for over fifteen years as a member representing the public on the federal Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC), a technical committee established by Congress to advise PHMSA on pipeline safety regulations.

Committee members are appointed by the Secretary of Transportation.

Served seven years, including position as its chairman, on the Washington State Citizens Committee on Pipeline Safety (CCOPS).

Positions are appointed by the governor of the state to advise federal, state, and local governments on regulatory matters related to pipeline safety, routing, construction, operation and maintenance.

Served on Executive subcommittee advising Congress and PHMSA on a report that culminated in new federal rules concerning Distribution Integrity Management Program (DIMP) gas distribution pipeline safety regulations.

As a representative of the public, advised the Office of Pipeline Safety on proposed new liquid and gas transmission pipeline integrity management rulemaking following the pipeline tragedies in Bellingham, Washington (1999) and Carlsbad, New Mexico (2000).

Member of Control Room Management committee assisting PHMSA on development of pipeline safety Control Room Management (CRM) regulations.

Certified and experienced HAZOP Team Leader associated with process safety management and application.

Education:

MBA (1976)

BS Chemical Engineering (1973)

BS Chemistry (1973)

Pepperdine University, Los Angeles, CA

University of California, Davis, CA

University of California, Davis, CA

Publications in the Public Domain:

1. "An Assessment of First Responder Readiness for Pipeline Emergencies in the State of Washington," prepared for the Office of the State Fire Marshall, by Hanson Engineers Inc., Elway Research Inc., and Accufacts Inc., and dated June 26, 2001.
2. "Preventing Pipeline Failures," prepared for the State of Washington Joint Legislative Audit and Review Committee ("JLARC"), by Richard B. Kuprewicz, President of Accufacts Inc., dated December 30, 2002.
3. "Pipelines - National Security and the Public's Right-to-Know," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated May 14, 2003.
4. "Preventing Pipeline Releases," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated July 22, 2003.
5. "Pipeline Integrity and Direct Assessment, A Layman's Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated November 18, 2004.
6. "Public Safety and FERC's LNG Spin, What Citizens Aren't Being Told," jointly authored by Richard B. Kuprewicz, President of Accufacts Inc., Clifford A. Goudey, Outreach Coordinator MIT Sea Grant College Program, and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated May 14, 2005.
7. "A Simple Perspective on Excess Flow Valve Effectiveness in Gas Distribution System Service Lines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated July 18, 2005.
8. "Observations on the Application of Smart Pigging on Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated September 5, 2005.
9. "The Proposed Corrib Onshore System - An Independent Analysis," prepared for the Centre for Public Inquiry by Richard B. Kuprewicz, dated October 24, 2005.
10. "Observations on Sakhalin II Transmission Pipelines," prepared for The Wild Salmon Center by Richard B. Kuprewicz, dated February 24, 2006.
11. "Increasing MAOP on U.S. Gas Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2006. This paper was also published in the June 26 and July 1, 2006 issues of the Oil & Gas Journal and in the December 2006 issue of the UK Global Pipeline Monthly magazines.
12. "An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick," prepared for the Friends of Rockwood Park, by Richard B. Kuprewicz, dated September 16, 2006.
13. "Commentary on the Risk Analysis for the Proposed Emera Brunswick Pipeline Through Saint John, NB," by Richard B. Kuprewicz, dated October 18, 2006.
14. "General Observations On the Myth of a Best International Pipeline Standard," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2007.
15. "Observations on Practical Leak Detection for Transmission Pipelines – An Experienced Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated August 30, 2007.
16. "Recommended Leak Detection Methods for the Keystone Pipeline in the Vicinity of the Fordville Aquifer," prepared for TransCanada Keystone L.P. by Richard B. Kuprewicz, President of Accufacts Inc., dated September 26, 2007.
17. "Increasing MOP on the Proposed Keystone XL 36-Inch Liquid Transmission Pipeline," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated February 6, 2009.
18. "Observations on Unified Command Drift River Fact Sheet No 1: Water Usage Options for the current Mt. Redoubt Volcano threat to the Drift River Oil Terminal," prepared for Cook Inletkeeper by Richard B. Kuprewicz, dated April 3, 2009.

19. "Observations on the Keystone XL Oil Pipeline DEIS," prepared for Plains Justice by Richard B. Kuprewicz, dated April 10, 2010.
20. "PADD III & PADD II Refinery Options for Canadian Bitumen Oil and the Keystone XL Pipeline," prepared for the Natural Resources Defense Council (NRDC), by Richard B. Kuprewicz, dated June 29, 2010.
21. "The State of Natural Gas Pipelines in Fort Worth," prepared for the Fort Worth League of Neighborhoods by Richard B. Kuprewicz, President of Accufacts Inc., and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated October, 2010.
22. "Accufacts' Independent Observations on the Chevron No. 2 Crude Oil Pipeline," prepared for the City of Salt Lake, Utah, by Richard B. Kuprewicz, dated January 30, 2011.
23. "Accufacts' Independent Analysis of New Proposed School Sites and Risks Associated with a Nearby HVL Pipeline," prepared for the Sylvania, Ohio School District, by Richard B. Kuprewicz, dated February 9, 2011.
24. "Accufacts' Report Concerning Issues Related to the 36-inch Natural Gas Pipeline and the Application of Appleview, LLC Premises: 7009 and 7010 River Road, North Bergen, NJ," prepared for the Galaxy Towers Condominium Association Inc., by Richard B. Kuprewicz, dated February 28, 2011.
25. "Prepared Testimony of Richard B. Kuprewicz Evaluating PG&E's Pipeline Safety Enhancement Plan," submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012.
26. "Evaluation of the Valve Automation Component of PG&E's Safety Enhancement Plan," extracted from full testimony submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012, Extracted Report issued February 20, 2012.
27. "Accufacts' Perspective on Enbridge Filing to NEB for Modifications on Line 9 Reversal Phase I Project," prepared for Equiterre Canada, by Richard B. Kuprewicz, Accufacts Inc., dated April 23, 2012.
28. "Accufacts' Evaluation of Tennessee Gas Pipeline 300 Line Expansion Projects in PA & NJ," prepared for the Delaware RiverKeeper Network, by Richard B. Kuprewicz, Accufacts Inc., dated June 27, 2012.
29. "Impact of an ONEOK NGL Pipeline Release in At-Risk Landslide and/or Sinkhole Karst Areas of Crook County, Wyoming," prepared for landowners, by Richard B. Kuprewicz, Accufacts Inc., and submitted to Crook County Commissioners, dated July 16, 2012.
30. "Impact of Processing Dilbit on the Proposed NPDES Permit for the BP Cherry Point Washington Refinery," prepared for the Puget Soundkeeper Alliance, by Richard B. Kuprewicz, Accufacts Inc., dated July 31, 2012.
31. "Analysis of SWG's Proposed Accelerated EVPP and P70VSP Replacement Plans, Public Utilities Commission of Nevada Docket Nos. 12-02019 and 12-04005," prepared for the State of Nevada Bureau of Consumer Protection, by Richard B. Kuprewicz, Accufacts Inc., dated August 17, 2012.
32. "Accufacts Inc. Most Probable Cause Findings of Three Oil Spills in Nigeria," prepared for Bohler Advocaten, by Richard B. Kuprewicz, Accufacts Inc., dated September 3, 2012.
33. "Observations on Proposed 12-inch NGL ONEOK Pipeline Route in Crook County Sensitive or Unstable Land Areas," prepared by Richard B. Kuprewicz, Accufacts Inc., dated September 13, 2012.
34. "Findings from Analysis of CEII Confidential Data Supplied to Accufacts Concerning the Millennium Pipeline Company L.L.C. Minisink Compressor Project Application to FERC, Docket No. CP11-515-000," prepared by Richard B. Kuprewicz, Accufacts Inc., for Minisink Residents for Environmental Preservation and Safety (MREPS), dated November 25, 2012.
35. "Supplemental Observations from Analysis of CEII Confidential Data Supplied to Accufacts Concerning Tennessee Gas Pipeline's Northeast Upgrade Project," prepared by Richard B. Kuprewicz, Accufacts Inc., for Delaware RiverKeeper Network, dated December 19, 2012.

36. "Report on Pipeline Safety for Enbridge's Line 9B Application to NEB," prepared by Richard B. Kuprewicz, Accufacts Inc., for Equiterre, dated August 5, 2013.
37. "Accufacts' Evaluation of Oil Spill Joint Investigation Visit Field Reporting Process for the Niger Delta Region of Nigeria," prepared by Richard B. Kuprewicz for Amnesty International, September 30, 2013.
38. "Accufacts' Expert Report on ExxonMobil Pipeline Company Silvertip Pipeline Rupture of July 1, 2011 into the Yellowstone River at the Laurel Crossing," prepared by Richard B. Kuprewicz, November 25, 2013.
39. "Accufacts Inc. Evaluation of Transco's 42-inch Skillman Loop submissions to FERC concerning the Princeton Ridge, NJ segment," prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated June 26, 2014, and submitted to FERC Docket No. CP13-551.
40. Accufacts report "DTI Myersville Compressor Station and Dominion Cove Point Project Interlinks," prepared by Richard B. Kuprewicz for Earthjustice, dated August 13, 2014, and submitted to FERC Docket No. CP13-113-000.
41. "Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco's Leidy Southeast Expansion Project," prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated September 3, 2014, and submitted to FERC Docket No. CP13-551.
42. Accufacts' "Evaluation of Actual Velocity Critical Issues Related to Transco's Leidy Expansion Project," prepared by Richard B. Kuprewicz for Delaware Riverkeeper Network, dated September 8, 2014, and submitted to FERC Docket No. CP13-551.
43. "Accufacts' Report to Portland Water District on the Portland – Montreal Pipeline," with Appendix, prepared by Richard B. Kuprewicz for the Portland, ME Water District, dated July 28, 2014.
44. "Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco's Leidy Southeast Expansion Project," prepared by Richard B. Kuprewicz and submitted to FERC Docket No. CP13-551.
45. Review of Algonquin Gas Transmission LLC's Algonquin Incremental Market ("AIM Project"), Impacting the Town of Cortlandt, NY, FERC Docket No. CP14-96-0000, Increasing System Capacity from 2.6 Billion Cubic Feet (Bcf/d) to 2.93 Bcf/d," prepared by Richard B. Kuprewicz, and dated Nov. 3, 2014.
46. Accufacts' Key Observations dated January 6, 2015 on Spectra's Recent Responses to FERC Staff's Data Request on the Algonquin Gas Transmission Proposal (aka "AIM Project"), FERC Docket No. CP 14-96-000) related to Accufacts' Nov. 3, 2014 Report and prepared by Richard B. Kuprewicz.
47. Accufacts' Report on Mariner East Project Affecting West Goshen Township, dated March 6, 2015, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.
48. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing on the Proposed System Integrity Projects ("SIP") to the Mississippi Public Service Commission ("MPSC") under Docket No. 15-UN-049 ("Docket"), prepared by Richard B. Kuprewicz, dated June 12, 2015.
49. Accufacts' Report to the Shwx'owhamel First Nations and the Peters Band ("First Nations") on the Trans Mountain Expansion Project ("TMEP") filing to the Canadian NEB, prepared by Richard B. Kuprewicz, dated April 24, 2015.
50. Accufacts Report Concerning Review of Siting of Transco New Compressor and Metering Station, and Possible New Jersey Intrastate Transmission Pipeline Within the Township of Chesterfield, NJ ("Township"), to the Township of Chesterfield, NJ, dated February 18, 2016.
51. Accufacts Report, "Accufacts Expert Analysis of Humberplex Developments Inc. v. TransCanada Pipelines Limited and Enbridge Gas Distribution Inc.; Application under Section 112 of the National Energy Board Act, R.S.C. 1985, c. N-7," dated April 26, 2016, filed with the Canadian Nation Energy Board (NEB).
52. Accufacts Report, "A Review, Analysis and Comments on Engineering Critical Assessments as proposed in

PHMSA's Proposed Rule on Safety of Gas Transmission and Gathering Pipelines," prepared for Pipeline Safety Trust by Richard B. Kuprewicz, dated May 16, 2016.

53. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing to the Mississippi Public Utilities Staff, "Accufacts Review of Atmos Spending Proposal 2017 – 2021 (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 15, 2016.
54. Accufacts Report, "Accufacts Review of the U.S. Army Corps of Engineers (USACE) Environmental Assessment (EA) for the Dakota Access Pipeline ("DAPL")," prepared for Earthjustice by Richard B. Kuprewicz, dated October 28, 2016.
55. Accufacts' Report on Mariner East 2 Expansion Project Affecting West Goshen Township, dated January 6, 2017, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.
56. Accufacts Review of Puget Sound Energy's Energize Eastside Transmission project along Olympic Pipe Line's two petroleum pipelines crossing the City of Newcastle, for the City of Newcastle, WA, June 20, 2017.
57. Accufacts Review of the Draft Environmental Impact Statement for the Line 3 Pipeline Project Prepared for the Minnesota Department of Commerce, July 9, 2017, filed on behalf of Friends of the Headwaters, to Minnesota State Department of Commerce for Docket Nos. CN-14-916 & PPL-15-137.
58. Testimony of Richard B. Kuprewicz, president of Accufacts Inc., in the matter West Goshen Township and Concerned Citizens of West Goshen Township v. Sunoco Pipelines, L.P. before the Pennsylvania Public Utilities Commission, Docket No. C-2017-2589346, on July 18, 2017, on Behalf of West Goshen Township and Concerned Citizens of West Goshen Township.
59. Direct Testimony of Richard B. Kuprewicz, president of Accufacts Inc., on Behalf of Friends of the Headwaters regarding Enbridge Energy, Limited Partnership proposal to replace and reroute an existing Line 3 to the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (MPUC PL-9/CN-14-916 and MPUC PL-9/PPL-15-137), September 11, 2017 and October 23, 2017.
60. Direct Testimony of Richard B. Kuprewicz On Behalf of The District of Columbia Government, before the Public Service Commission of the District of Columbia, in the matter of the merger of AltaGas Ltd. and WGL Holdings, Inc., Formal Case No. 1142, September 29, 2017.
61. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2018 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated December 4, 2017.
62. Report to Hugh A. Donaghue, Esquire, Concord Township Solicitor, "Accufacts Comments on Adelphia Project Application to FERC (Docket No. CP18-46-000) as it might impact Concord Township," dated May 30, 2018.
63. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2019 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 20, 2018.
64. Report to West Goshen Township Manager, PA, "Accufacts report on the repurposing of an existing 12-inch Sunoco pipeline segment to interconnect with the Mariner East 2 and Mariner East 2X crossing West Goshen Township," dated November 8, 2018.
65. Report to West Whiteland Township Manager, PA, "Accufacts Observations on Possible Pennsylvania State Pipeline Safety Regulations," prepared by Richard B. Kuprewicz, dated March 22, 2019.
66. Accufacts Public Comments on the Proposed Joint Settlement, BI&E v. Sunoco Pipeline L.P. ("SPLP"), Docket No. C-2018-3006534 ("Proposed Settlement"), submitted on August 15, 2019 to the Pennsylvania Public Utility Commission on the behalf of West Goshen Township as an intervener.
67. Report to West Whiteland Township Manager, Ms. Mimi Gleason, "Accufacts Perspective on Two Questions from West Whiteland's Board of Supervisors on Proposed Changes to ME 2 and ME 2X Construction/Operational Activities within West Whiteland," dated September 5, 2019."

68. Report to West Goshen Township Manager, Mr. Casey LaLonde, "Accufacts Report on the episode on the evening of 8-5-19 at the Mariner East Boot Road Pump Station ("Event"), Boot Road, West Goshen Township, PA," dated September 16, 2019.
69. Provided direct testimony before the Arizona Corporation Commission, In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on Fair Value of the Properties of Southwest Gas Corporation Devoted to its Arizona Operations (Docket No. G-01551A-19-0055), testified on behalf of Utilities Division Arizona Corporation Commission, February 19, 2020.
70. Report to West Goshen Township Manager, Mr. Casey LaLonde, "Accufacts Report on the Mariner East 2X Pipeline Affecting West Goshen Township," dated July 23, 2020.
71. Assisted the Commonwealth of Massachusetts, Office of the Attorney General in developing pipeline safety processes to be incorporated into the settlement agreement related to Columbia Gas' sale of Assets to Eversource following the Merrimack Valley, Massachusetts overpressure event of September 13, 2018.
72. Report to Natural Resources Defense Council, Inc., "Accufacts' Observations on the Use of Keystone XL Pipeline Pipe Exhibiting External Coating Deterioration Issues from Long Term Storage Exposure to the Elements," October 1, 2020.
73. Report to Pennsylvania Public Utilities Commission ("PAPUC"), "Accufacts Comments on Proposed Pennsylvania Intrastate Liquid Pipeline Safety Regulations," dated October 29, 2021, prepared for West Whiteland Township Board of Supervisors, West Whiteland Township, PA. Filed to PAPUC public web docket November 5, 2021 by West Whiteland Township under Reference Docket Number L-2019-3010267. Addresses suggested improvements in proposed pipeline safety rules for PA intrastate liquid transmission pipelines.
74. Submitted written testimony of Richard B. Kuprewicz on Behalf of Bay Mills Indian Community to ALJ Dennis Mack, dated December 14, 2021, in the matter of the Application of Enbridge Energy, Limited Partnership for Authority to Replace and Relocate the Segment of Line 5 Crossing the Straits of Mackinac into a Tunnel Beneath the Straits of Mackinac, before the State of Michigan Public Service Commission, U-20763.
75. Public presentation to New York State Indian Point Nuclear Facility Decommissioning Oversight Board on Holtec removal activities in proximity to Enbridge three Natural Gas Transmission Pipelines, March 17, 2022.
76. Report to Pipeline Safety Trust and Bold Alliance, "Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.," March 23, 2022.
77. Accufacts Inc., Public Presentation for the National Academies of Science Engineering Medicine and The Transportation Research Board, "To Committee on Criteria for Installing Automatic and Remote-Controlled Shutoff Valves on Existing Gas and Hazardous Liquid Transmission Pipelines," 4/27/22.
78. Accufacts Inc, "6/13/22 Webinar to Illinois Emergency Responders, Healthcare Providers, & Local Officials on Responses to CO₂ Transmission Pipeline Releases," 6/13/22.
79. Accufacts Report for Pipeline Safety Trust, "Safety of Hydrogen Transportation by Gas Pipelines," 11/28/22.
80. Completed a series of testimonies related to Enbridge's Line 5 proposal to replace 2 – 20-inch diameter existing submerged pipelines currently lying across the bottom of the Straits of Mackinac with a 30-inch diameter grade X-70 pipeline, proposed to be installed in a 21-foot diameter concrete tunnel to be installed across the approximate 4-mile span of the Straits of Mackinac. Testified on Behalf of the Bay Mill Indian Community before the State of Michigan Public Service Commission, Docket U-20763, in opposition to this very poorly designed proposal/installation allowing for movement of the pipeline on rollers within the tunnel. Final testimony to the docket submitted May 19, 2023. This is the only pipeline proposal I am aware of in the world that would place a crude oil and liquid propane pipeline, especially a 30-inch diameter pipeline, within a tunnel.
81. Issued to Ms. Niroop Srivatsa, City Manager, "Accufacts Report for the City of Lafayette on the Status of the Tree Assessment Process with PG&E," indicating most of the trees identified for removal by PG&E risk management

approach have nothing to do with gas pipeline safety, June 15, 2023.

82. Issued Direct Testimony to Illinois Commerce Commission (“ICC”) on the Navigator Heartland Greenway LLC Application for a Carbon Dioxide Transportation and Sequestration pipeline, under Docket 23-0161, on behalf of Citizens Against Heartland Pipeline (“CAHGP”), McDonough County, Christian County and Hancock County (the “Counties”) (jointly, “Citizen and County Intervenor” of “CCI”), raising serious questions as to PHMSA’s recent assertions of pipeline safety jurisdiction, and underscoring the ICC’s authority for pipeline siting jurisdiction of said pipeline proposal in the State of Illinois, filed June 15, 2023. Applicant has terminated their application.
83. Issued Direct Testimony to Illinois Commerce Commission (“ICC”) on the WOLF Carbon Solutions US LLC Application for a Carbon Dioxide Transportation and Sequestration pipeline, under Docket 23-0475, for a certificate of authority to construct and operate a carbon dioxide pipeline and when necessary to take interest in property as provided by law of eminent domain, testifying on Behalf of Citizens Against Predatory Pipelines (“CAPP”): 1) identifying serious inadequacies in PHMSA’s pipeline safety regulations, 2) explaining why the Commission should require pipeline temperature profiles 3) detailing why DNV-RP-F104 is not relevant to this filing and 4) underscoring the ICC’s authority to require additional critical information from the Applicant in this matter, filed October 24, 2023. Applicant has withdrawn their submission to the Commission.
84. Provided general summary, main observations/concerns, on “Draft Environmental Impact Statement: Otter Tail to Wilkin Carbon Dioxide Pipeline Project” submitted to Minnesota Public Utilities Commission regarding Summit Carbon Solutions, LLC proposed 28 mile long 4-inch diameter CO₂ liquid transmission pipeline (“Otter Tail Pipeline”) within Minnesota, PUC Docket No. IP-7093/PPL-22-422, provided to Clean Up the River Environment (“CURE”) on 1/29/2024.
85. Issued to EarthJustice, “Observations concerning Kern County’s Draft Environmental Impact Report (“DEIR”) on the TerraVault I Carbon Capture and Storage Project (“Project”),” dated February 26, 2024, “Observations concerning Kern County’s Recent Recirculated Draft Environmental Impact Report (“RDEIR”) on the TerraVault I Carbon Capture and Storage Project (“Project”),” dated July 17, 2024, and “Evaluation of Kern County Response to Comments and Final Recirculated Environmental Impact Report on the TerraVault I Carbon Capture and Storage Project, dated October 15, 2024. The Project situated in Kern County is proposed by the California Resources Corporation to separate a portion of the pre-combustion Elk Hills field gas production, treat and inject via liquid transmission pipelines, CO₂ into two sequestration injection wells within the Elk Hill oil field. The reports identify many technical gaps in filings to Kern County.
86. Issued for the Tribal Partnerships Program, “Observations on the U.S. Army Corps of Engineers Draft Environmental Assessment, Clean Water Act Section 404(b)(1) Guidelines Evaluation, and Public Interest Review (collectively referenced as “DCDD”) for the Enbridge Line 5 Wisconsin Segment Relocation Project (“Project”), dated May 2024,” report dated July 31, 2024 affecting the Bad River Band of the Lake Superior Tribe of Chippewa Indians reservation.

Exhibit C

Accufacts Inc.

“Clear Knowledge in the Over Information Age”

***Observations on OSFM Letters of Decision for
State Waiver Requests on Line CA-324 and CA-
325A/B Related to Possible Restart***

Prepared For

**The Center for Biological Diversity
&
The Environmental Defense Center**

February 21, 2025

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I. Summary.

Accufacts Inc. (“Accufacts”) was asked to provide my expert opinion on the Letters of Decision on the State Waivers for the startup of Line CA-324, CA-325A, and CA-325B (“Pipelines”) made public in mid-January 2025 by the Office of the State Fire Marshal (“OSFM”).¹ This report builds on a previous Accufacts report issued on December 20, 2024.² By agreement, a Consent Decree gives the OSFM main pipeline safety approval authority of the Pipelines if the OSFM’s actions are not in conflict with PHMSA pipeline safety regulations, and if PHMSA decides the proposed state waiver alternative measures “provide an equal or greater level of safety.”³ It is my understanding that PHMSA can choose to: 1) Not comment on this matter allowing the State Waiver to occur and startup to proceed, 2) Not approve the waiver preventing the startup, or 3) Impose additional requirements to assure an equal or greater level of safety to current minimum federal pipeline safety regulations occurs.

The current coating installations do not provide “limited effectiveness of the cathodic protection system,” as mentioned by the Decision letters issued by the OSFM. This I believe is a poor choice of words that understates the fact that the CP system is ineffective on most of the Pipelines’ mileage. The OSFM is thus being asked to grant a state waiver on federal pipeline safety minimum requirements intended to address external pipeline corrosion from an ineffective CP installation, while relying on hydrotesting and various forms of inline inspection, ILI or smart pigging, to avoid pipeline failure from the resulting external corrosion.

The waivers attempt to allow startup of the Pipelines relying mainly on ILI technology to identify corrosion threats before failure. In addition, the Application by the Pipeline’s operator appears to be relying on a circumferential magnetic flux leakage (MFL-C tool) approach run in February 2022 to argue for the removal of federal regulation requiring the 180 day condition for scheduling remediation of “corrosion of or along a longitudinal seam weld.”^{4, 5} Our experience with MFL-C tools is that if certain parameters are not incorporated, such ILI tools can miss a lot of cracks. I see no mention of such important conditions in the referenced letter that would demonstrate that this ILI run is reliable. I do not see sufficient justification to waive 49CFR452(h)(4)(iii)(H) as such a waiver would not provide an equal or greater level of safety as no carbon steel pipeline, even new modern steel pipelines, are invincible to corrosion attack.

¹ OSFM letter to Sable/PPC Offshore Corp, “Letter of Decision on the Sate Waiver Request for Limited Effectiveness of Cathodic Protection on Thermally Insulated Pipeline and Corrosion of or Along a Longitudinal Seam Weld (CA-324) (“Decision Letter 324”) and Letter of Decision on the State Waiver Request for Limited Effectiveness of Cathodic Protection on Thermally Insulated Pipeline and Corrosion of or Along a Longitudinal Seam Weld (CA-325A/B) (“Decision Letter 325A/B”)", dated 12/17/24.

² Accufacts, “Evaluation of Las Flores Pipeline System Startup Proposal,” prepared for The Center for Biological Diversity & The Environmental Defense Center, December 20, 2024.

³ PHMSA website: <https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-and-state-waivers-overview>.

⁴ Pacific Pipeline Company (Aka now as Sable/PPC) letter to OSFM, “Subject Pacific Pipeline Company (OPID 40475) State Waiver Application for the Las Flores Pipeline CA-324 (OSFM #00115),” July 10, 2023, p. 5 related to MFL-C February 2020 ILI run.

⁵ 49CFR452(h)(4)(iii)(H).

A simple plot of the type and approximate milepost location of external corrosion such as wall loss or cracking, including field as well as ILI indications along the Pipelines, will underscore how challenging the operation of the present Pipelines will be without effective CP. Such a plot will clearly demonstrate that the Pipelines are not “like new” as indicated by some recent Sable/PPC representatives. Further explanation is also warranted as to why the pipeline operator assumes there is no SCC or SSC risks associated with water on the Pipelines.

A proposal to replace the Pipelines with a new smaller diameter heated pipeline that would be uninsulated and built with modern unshielding coatings was aborted.⁶ This proposal would have permitted the CP system to do its job addressing external corrosion, while complying with federal pipeline regulation.

II. The current installation renders the CP system ineffective.

The construction of Line 324 in the late 1980s utilized coal tar urethane coating applied to the bare steel pipeline, covered by sprayed on insulation to assure the pipeline was operated at higher temperatures. The insulation was then wrapped with a non-conductive polyethylene tape coating.⁷ While there may be some confusion as to the coating installation on what is now named 325A/B, information leads us to believe this coating installation is similar on these pipelines as that on Line 324. To anyone vaguely familiar with pipeline external corrosion protection and cathodic protection (“CP”) intent, this approach is a fundamental failure of design/installation reflecting much inexperience in pipelines. The polyethylene tape shields and prevents CP current from getting to the external pipeline steel, and the insulation system works to shield while increasing the likelihood of water in close proximity to the pipe, especially in areas where the coal tar coating directly on the pipeline steel has separated, or disbonded, from the pipe.⁸ With such heavy shielding there is thus no way for any CP system current to ever reach the pipeline to reduce/prevent external corrosion.

With the exception of a few feet of buried pipe that has undergone repairs, replacing the existing poor design and coating installations with a few feet of dual epoxy coatings, the shielded CP system is ineffective. The various threats of external corrosion on the Pipelines are exacerbated by the elevated temperature, the potential for water to accumulate along the Pipelines via the insulation, the application of non-conducting tape wrap around the insulation, and the use of older coal tar coating directly on the pipeline that exhibits separation (aka disbondment) from the pipe steel. Disbonded coating in the wrong environments is especially conducive to cracking threats, such as SCC or SSC as discussed in this report. I have seen no convincing arguments that water environments conducive to corrosion cracking are not around or under the coating on the Pipelines.

⁶ Plains Administrative Draft EIR, “Plains Replacement Pipeline Project,” February 2022.

⁷ U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (“PHMSA”), “Failure Investigation Report Plains Pipeline LP, Line 901 Crude Oil Release, May 19, 2015, Santa Barbara County, California, May 2016, Appendix E: Corrosion Control and Pipeline Conditions, page 1 of 4.

⁸ *Ibid.*, Page 3 of 21, and Mechanical and Metallurgical Testing, Photos Figure 1 through 20.

III. Compliance with CP regulatory requirements is ineffective, making performance with this regulatory requirement meaningless.

The Pipelines thus have ineffective CP protection from external corrosion that is exacerbated by operation of the Pipelines at elevated temperatures, seriously increasing corrosion rate as discussed in my previous report.⁹ Attempts to gauge the effectiveness of the CP system utilizing CP performance measures identified in PHMSA regulations are meaningless in such heavily shielded installations. Just operating the Pipeline with CP “on” to meet federal minimum regulatory requirements will not prevent external corrosion attacks that can take on various forms on the Pipelines. It should be noted that the OSFM has required “Where the operator discovers external corrosion in combination with coating deterioration, the operator must recoat with a two-part epoxy. Sable must recoat in accordance with their repair procedure.” which does allow repair replacing with the existing installation approach, given its many shortcomings to prevent external corrosion.¹⁰ This requirement places the responsibility on the pipeline operator to identify when or if any, field digs should occur to confirm coating degradation. The operator should be primarily focused on identifying environments around the pipeline that are precursors to various forms of external corrosion attack, given the many conditions related to the pipeline design/installation conducive to external corrosion attack.

It is on the limited repaired sections, measured in feet, that the CP should be effective as such short length repairs replace the poorly designed shielding original coating installations. For the vast majority of the Pipelines mileage, however, the CP remains ineffective. The requirements to measure CP performance stated in 49CFR§195.2 (NACE SP 0169 – 2007 edition, paragraph 6.2.2) are meaningless when heavy shielding, such as that which occurs on CA-324 and CA-325A/B, prevents CP current from reaching the pipeline.

IV. This is more than simple corrosion under installation (CUI) issue.

Considerable past discussions have suggested that this is a corrosion under installation (or CUI”) problem implying that this is the only controlling issue. While CUI is certainly a contributing factor, the corrosion threats go well beyond CUI. As previously discussed, heavy shielding, the tape coating around the insulation, the vintage/type of coating directly on the Pipelines prone to disbondment, the operating temperature, and the environment around the Pipelines, work in concert to create external corrosion in its various forms. The Consent Decree is an agreement based on the premise that higher risks of external corrosion can be mainly addressed by ILI tools. The multiple forms of external corrosion which can occur on the Pipelines require various different approaches, beyond ILI, as discussed further in this report.

⁹ Accufacts, “Evaluation of Las Flores Pipeline System Startup Proposal,” prepared for The Center for Biological Diversity & The Environmental Defense Center, December 20, 2024, p. 13.

¹⁰ OS OSFM letter to Sable/PPC Offshore Corp, “Decision Letter 324 and Decision Letter 325A/B”),” dated 12/17/24, pp. 11 and 11 respectively.

V. External corrosion on buried pipelines falls into four major categories.

External corrosion on buried steel pipelines falls into four general categories: 1) wall loss or thinning of the pipe wall, 2) cracking or crack-like, 3) pitting, and 4) corrosion within dents.

1. Pipe wall loss corrosion is generally understood to occur over larger areas of the pipe.

Internal or external corrosion can cause pipe wall thinning. Such thinning differs from pit corrosion discussed below, in that pipe wall loss thinning tends to occur over a wider area of the pipe. Despite previous multiple ILI runs, external corrosion pipe wall loss, or thinning, was the condition that resulted in the May 19, 2015 pipeline rupture failure. External corrosion on the shielded pipe allowed general corrosion thinning of the pipeline until the pipe failed under pressure. It should be worth noting that wall loss in excess of 0.8 wall thickness (actually 0.91) which occurred in the May 19, 2015 rupture, places the operator at great risks. Ironically, pipe wall loss is generally one pipeline failure threat that advances in the ILI technology over recent decades was intended to address, either with ILI mag flux or ultrasonic approaches which are different technical methods.

2. Cracking or crack-like corrosion is usually an environmental threat difficult to assess.

This is associated with various forms of pipeline cracking, such as selective seam corrosion or stress corrosion cracking. While engineers like to think they can calculate time to failure, such time to failure estimates for these forms of corrosions are hard to reliably predict. Given the probability that such cracking, especially if in clusters, can interact with other cracks, or weaknesses in the pipe body near/at welds, makes prediction to failure highly unreliable. Such pipe weaknesses can occur at weld heat affected zones, at girth welds, or at manufacturing related pipe seams, in unpredictable ways that can quickly negate time to failure calculation/estimates, even if cracking potential is identified.

Sable/PPC has requested an exemption from 49CFR452(h)(4)(iii)(H) explaining this is usually a SSC threat related to earlier vintage manufacturing processes such as LF-ERW which tends to exhibit lower pipe toughness. There are other related risks to the manufacturing process of modern steels such as DSAW and HF-ERW concerning cracking potential from poor coating/ineffective CP approaches. Because of the nature of disbanded coating in proximity to water, coating can tent at weld seams creating potential for cracking corrosion attack, such as SSC. Even modern pipe steels are not invincible to such cracking corrosion potential, especially on pipelines operating at elevated temperatures. Unless the operator can show why such environments don't exist, their request to be exempted from 49CFR452(h)(4)(iii)(H) should be denied. These explanations should go well beyond a MAG-C pig run the pipeline operator has provided.

3. Pitting corrosion is a special form of wall loss that is difficult to identify via ILI.

This is the loss of pipe steel in concentrated small areas, forming localized small holes or pits, usually at girth welds, that can weaken the pipeline and cause a release. Pit corrosion identification via ILI, even newer generations of ILI tools, can be very challenging. Pit corrosion threats are usually verified via field digs or pipeline releases. While this threat can be a bona fide threat on the Pipelines that are heavily shielded rendering CP ineffective, there has been no mention that this threat has been identified.

4. Corrosion within dents is a special form of dent threat.

Corrosion or cracking within a dent, also known as “dents with stress concentrators” are hard to identify via ILI, and almost impossible to reliably predict time to failure. Such threats are usually identified by high-definition geometric ILI dent tools, the location around the pipeline, and field dig verification assessments. The ILI determination using high resolution caliper or geo pigs, have proven reliable at identifying dents and their location on a pipeline.

VI. Types of ILI technology.

Given the possible types of external corrosion on the Pipelines, I now focus on a simple high-level discussion of corrosion ILI technical approaches.

1. General wall loss corrosion.

After the advancement of geometric or deformation ILI technology, the next early phase of ILI use focused on general corrosion wall loss, or pipeline thinning along the axis or flow direction of the pipeline. In this field, technology split into two different approaches, magnetic flux leakage and ultrasonic. Magnetic flux leakage (or mag flux) approaches utilized software algorithms to characterize changes in magnetic flux to identify wall loss aligned in the axial, or direction of flow, usually the most insidious and common corrosion flaws for pipe. Mag flux ILIs fall into two general categories: low resolution (usually associated with earlier generation) and high resolution (usually more complex and more expensive). Mag flux technology shifted from low resolution to the more sophisticated high resolution approaches where corrosion is problematic. There are still pipelines that utilize low resolution mag flux because of cost, so care should be exercised in the application of this form of ILI on liquid pipelines. The waivers specifically require UT ILI the first two years of operation, but are moot, indicating magnetic flux ILI in the future could be allowed without clarification as to high res or low res ILI.

Ultrasonic ILI approaches use beams of ultrasonic energy to identify both external and internal corrosion wall loss. While a simplification, ultrasonic approaches are analogous to radar, where reflected energy readings are utilized to measure changes in pipe wall thickness. Originally, ultrasonic approaches, focusing on wall loss evaluation, directed UT energy directly into the pipe in the radial direction for wall thickness and resulting wall loss corrosion sizing determinations.

2. Cracking corrosion.

Pipeline ruptures from cracking threats drove a need for ILI tool cracking development. Thus, a next generation of ultrasonic ILI approaches advanced by changing the angle of the UT beam from radial into the pipe to at an angle to help spot cracks that might be developing. This form of UT approach is identified as shear wave. As more pipeline failures from cracking were uncovered, additional advances known as phased array ultrasonic (PAUT) have recently developed, though such measurements are currently focused on field measurement of uncovered pipeline, as ILI in this area I would categorize as still under development.

I have investigated too many pipeline ruptures that occurred after an ILI run which indicates more regulatory work is needed in ILI regulations related to applications of ILI. No ILI vendor provides such tools claiming they will not work. It is the pipeline operator's responsibility to ensure ILI runs meet the restrictions placed by the tool vendor (such as speed) and to verify the tool vendor's claimed capability with a proper number of field verification digs.

VII. What is the purpose of hydrotesting?

There are basically two types of hydrotesting mentioned in federal pipeline safety: 1) What I call a subpart E, or proof of MOP test, and 2) a crack hydrotest, what is referred to as a "spike hydrotest" that is performed at much higher test pressures as a %SMYS. Both forms of hydrotesting are proof test, good at the time of the test, and don't characterize time dependent pipeline threats such as corrosion.

The purpose of an MOP hydrotest is to proof the fitness for service of a pipeline at the time of the test, with a certain margin of pressure safety that usually deteriorates with time. Subpart E MOP tests are not crack integrity test. If a pipeline system has crack forming potential an MOP test is not appropriate.

Spike hydrotests are meant to avoid pressure reversals associated with crack threats on pipelines. Pressure reversals are where cracks remaining after MOP hydrotest tests can enlarge for various reasons to result in possible failure during operation, usually at lower pressures. It is my experience that spike hydrotests are meant to deal with cracking threats if such a threat exists. The performance metric for the suitability of a spike hydrotest is the range of %SMYS for the specific test segment. For pipeline elevation changes like that associated with 325A/B, a spike hydrotest requires the pipeline be segmented to keep test pressures within reasonable ranges that don't produce permanent yielding of the pipe. The information made public to date indicates that the previous hydrotests performed in 1986, because of elevation changes, required Line 325A to undergo hydrotesting in 9 segments and in Line 325B in 11 segments. Unfortunately, the hydrotest segments in the public record application are identified by station number and not by approximate milepost. Since there is usually no correlation between station number and milepost, I thus cannot evaluate whether the Decision Letter 325A/B pressure testing parameters are adequate for Line 325A.¹¹ It is worth noting that the Decision Letter 325A/B makes no mention of a subpart E

¹¹ Decision Letter 325A/B, "Pressure Testing," page 5.
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hydrotest or spike hydrotest on Line 325B. The proposed segments for hydrotests on 325A need to be identified by approximate milepost to permit evaluation as to whether the waiver requirements are appropriate. The reasons for hydrotesting exclusion on Line 325B need to be properly justified and made public by the OSFM.

VIII. The illusion that corrosion growth rate can be accurately predicted needs to be explained.

One of the critical parameters that I have observed in too many pipeline rupture investigations is that ILI can be utilized to accurately predict corrosion growth rates (“CGR”) to help set a critical ILI run timing, for example. The Pipelines essentially have no effective CP, operate as a higher temperature system, contain disbonded coating, incorporate heavy shielding which prevents CP from reaching the Pipelines and operate with insulation that moves water on/near the outside of the pipe. Such a combination of factors can provide a wide variation in types of external corrosion as well as corrosion rate estimates. CGR estimates can be especially problematic if CGR approaches miss possible corrosion interaction threats that can considerably shorten time to failure estimates. I advise that CGR be utilized with extreme caution given this possible variation, especially for corrosion threats that can interact, such as SCC, whose time to failure can be highly unpredictable. Corrosion growth rate estimates can vary considerably given the various form of external corrosion, especially related to cracking in combination with its location near sensitive pipe locations such as seam or girth welds.

IX. Major state waiver deficiencies:

Key observation on the state waivers for the Pipelines:

1. A key corrosion performance tracking process step in the state waivers for the Pipelines is missing.

While not specially required in minimum pipeline safety regulations or the waivers, a prudent pipeline operator on a pipeline system highly susceptible to corrosion will plot or graph corrosion indications by type and severity, by approximate milepost. This is especially important on the Pipelines given their history of extensive corrosion caused by the lack of CP effectiveness, poor coating types causing disbondment or shielding, increased temperature, insulation that tends to wick water, and poor performance of ILI. Such graphing aids a pipeline operator in understanding possible corrosion “hot spot” segments whose threats on a pipeline increase because of environmental factors that merit additional assessment, and maybe even pipeline segment replacement from a corrosion point of view.

Care also needs to be taken that all corrosion sites are prudently evaluated for possible interactive threats, such as general wall loss in combination with cracking, or near pipe welds, such as that which can occur with cluster corrosion. I see no mention in the Letters of Decision and waivers requiring such important corrosion tracking on the Pipelines.

2. A major state waiver deficiency for Line 324.

Given the pipeline properties stated for Line 324 (a single grade X65, 0.344 in wall thickness, 24-inch diameter, HF-ERW), I can calculate the various % SMYS for the spike (minimum and maximum test pressures, and MOP hydrotests) based on an estimated approximate elevation profile by milepost as Line 324 can be hydrotested as one segment given its limited elevation profile.

A critical condition in the OSFM Decision letter 324 is:

- “12. Prior to placing the pipeline in operation, Sable must conduct a spike hydrostatic pressure test of the state waiver pipeline segments at a minimum pressure that is at least 1.5 times the MOP or 100% SMYS, for a minimum of 15 minutes after the spike hydrotest is stabilized. Sable must field evaluate and remediate the following anomalies before performing the spike hydrostatic test on CA-324:
- a. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.
 - b. All anomalies that have a predicted failure pressure less than or equal to 1.6 times MOP.”¹²

For the 24-inch diameter pipe, wall thickness and grade stated in the Decision Letter 324, 100% SMYS calculates to 1863 psig. 1.5 times the stated MOP of 1003 psig calculates to 1504 psig, at the highest elevation point. Thus, the spike test at the highest elevation point as required above is likely to be the lower maximum test pressure of 1504 psig which calculates to about 81% SMYS, **a value I believe is too low for corrosion cracking screening and evaluation.** The OSFM needs to explain why the proposed spike hydrotest of Line 324 is so low.

The bottom line is that Sable/PPCs should demonstrate whether there are environmental conditions around Line 324 that are conducive to cracking either SCC or SSC, and these conditions should go well beyond a Mag-C tool run (such as sufficient field digs to verify the ILI tool’s claimed capability). I see no such important conditions in Sable/PPCs application that instill confidence that Line 324 does not have environments favoring external cracking. While it is true that certain pipe manufactured before 1970 is more prone to SSC, or SSWC, for various reasons, there is no modern pipe, even HF-ERW located in Line 324 or DSAW located in 325 A/B, that is invincible to such corrosion cracking threats, especially if the coating directly applied to the pipe has “tented” on the weld seam, allowing water to enter between the coating and the pipe to create a corrosion cell. There is no carbon steel pipeline, even new modern manufactured steel pipelines, invincible to such corrosion attack.

¹² Decision Letter 324, “Pressure Testing,” pages 4 – 5.
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3. Major state waiver deficiencies for Line 325A/B.

Decision Letter 325 states that Line 325A and 325B is composed of 30-inch diameter of two pipe grades (X65 with a thickness of mainly 0.344 inch and X70 with a wall thickness mainly of 0.281 inches composed of DSAW, with one small segment of 0.03 miles containing HF-ERW). I used the term “mainly” as Sable’s/PPC’s application indicates these two lines are also largely composed of these grades with a small percentage of varying thicknesses.¹³ For these two pipe grades, and thicknesses, 100 % SMYS calculates to 1490 psig for X65 and 1311 psig for X70. Since the location of the various pipe grades by approximate mileposts within CA-325A/B are not indicated, and given the dramatic elevation profiles for 325A/B the proposed hydrotest segments, if any, by milepost and elevation segments need to be made public. Without such information, I cannot calculate the % SMYS range for hydrotests given the OSFM conditions. Hydrotest segments are identified by station number which don’t necessarily sync with milepost or MP.¹⁴ **These important test segment parameters, by approximate MP, and elevation need to be made public to assure prudent hydrotesting is being required to address the possible general corrosion and cracking risks on Line 325A/B.**

It is worth noting that the OSFM does not require a MOP and spike hydrotest of 325B which has very significant elevation changes. This would suggest that Line 325B is not being evaluated by hydrotesting. The reason(s) for this decision needs to be made public.

X. Conclusions.

Hydrotest segments proposed for the Pipelines need to be made transparent and include approximate MP, given the major role that elevation change plays on this system. Critical parameters related to location by milepost of the varying grades and thicknesses of pipe on 325 A/B and their associated hydrotest segments need to be identified by approximate MP as well, to verify if the OSFM parameters are sufficient for the specific types of corrosion threat. The reason as to why a spike hydrotest on 324 and 325 A are limited needs to be explained, as well as to why 325B hydrotesting has not been included in either a subpart E or spike hydrotest,

The incompleteness of the waivers lead me to conclude that I cannot determine the waivers provide sufficient information to assure an equal or greater level of safety for the Pipelines had the operator had an unshielded coating design that complied with federal minimum pipeline CP protection intended to avoid pipeline failure from external corrosion.

Richard B. Kuprewicz
President
Accufacts Inc.



¹³ Sable/PPC letter to OSFM, “Subject Pacific Pipeline Company (OPID 40475) State Waiver Application for the Las Flores Pipeline CA-324 (OSFM #00115). Pipeline System Background Data Attachment B of State Application Table B-3 Line Pipe Specifications,” July 2023, p. 4.

¹⁴ *Ibid.*, “Table B-6 Historic Hydrotest Summary,” p. 6.
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EXHIBIT C



U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue SE
Washington, DC 20590

MAY 21 2015

VIA CERTIFIED MAIL AND FAX TO: 713-646-4378

Troy Valenzuela
Vice President EHS
Plains Pipeline, LP
333 Clay Street, Suite 1600
Houston, TX 77002

Re: CPF No. 5-2015-5011H

Dear Mr. Valenzuela:

Enclosed is a Corrective Action Order issued in the above-referenced case. It requires Plains Pipeline, LP to take certain corrective actions with respect to Line 901 of your pipeline system that failed on May 19, 2015, near Santa Barbara, CA. Service is being made by certified mail and facsimile. Service of the Corrective Action Order by electronic transmission is deemed complete upon transmission and acknowledgement of receipt, or as otherwise provided under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon completion of service.

Thank you for your cooperation in this matter.

Sincerely,

her Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Ms. Linda Daugherty, Deputy Associate Administrator for Field Operations, OPS
Mr. Chris Hoidal, Director, Western Region, OPS

**U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590**

_____)
In the Matter of)

Plains Pipeline, LP,)

Respondent.)
_____)

CPF No. 5-2015-5011H

CORRECTIVE ACTION ORDER

Purpose and Background:

This Corrective Action Order (Order) is being issued, under the authority of 49 U.S.C. § 60112, to require Plains Pipeline, LP (Plains or Respondent), to take the necessary corrective action to protect the public, property, and the environment from potential hazards associated with the recent failure on your pipeline in Santa Barbara County, California.

On May 19, 2015, a reportable accident occurred on Plains' Line 901 pipeline, resulting in the release of approximately 1700 to 2500 barrels of heavy crude oil (Failure). Line 901 is a 24-inch diameter pipeline approximately 10.6 miles in length that transports crude oil from Exxon Mobil's breakout storage tanks in Las Flores Canyon to Plains' Gaviota Pump Station. The cause of the Failure has not yet been determined. Pursuant to 49 U.S.C. § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), initiated an investigation of the accident. The preliminary findings of the ongoing investigation are as follows:

Preliminary Findings:

- Plains Pipeline, LP (Plains), is a publicly traded master limited partnership that operates approximately 17,800 miles of crude oil and natural gas liquids pipelines and gathering systems throughout the United States, including California and Texas.¹
- The failed pipeline is a 24-inch diameter line that transports crude oil and runs from Exxon Mobil's breakout storage tanks in Las Flores Canyon to Plains' Gaviota Pump Station, a distance of approximately 10.6 miles (Affected Pipeline). The Failure occurred near milepost 4 near Goleta, California (Failure Site).

¹ <https://www.plainsallamerican.com/what-we-do/transportation> (last accessed May 20, 2015)

- The Affected Pipeline was constructed from 1987-1990, and consists of .344 wall thickness, X-65 high frequency electric resistance welded (ERW) pipe manufactured by Nippon Steel.
- The Affected Pipeline has a Maximum Operating Pressure (MOP) of 1025 psig and the normal operating pressure is 650 psig. Plains initially reported that the line pressure was approximately 700 psig immediately prior to failure.
- The initial hydrostatic test on the Affected Pipeline was conducted in October 1990, to a pressure of 1719 psig held for 8 hours.
- The Affected Pipeline is insulated and operates at up to 120 degrees Fahrenheit. There are shrink wrap sleeves at some of the pipeline's girth welds.
- The Affected Pipeline was recently smart-pigged on May 5, 2015. Complete in-line inspection (ILI) data was collected but the operator has not yet received a formal report from the ILI vendor regarding the analysis of the data and identification of any anomalies requiring further investigation according to the Federal pipeline safety regulations.
- Previous ILIs were performed in June 2007 and July 2012. In 2007 and 2012, there were 13 and 41 excavations of ILI-identified anomalies on the pipeline, respectively. These anomalies were mostly due to external corrosion, frequently located near the pipeline's girth welds.
- The Failure was discovered by the operator on May 19, 2015 around 1:30 p.m. PST, and reported to the National Response Center (NRC Report No. 1116972) at 2:56 p.m. PST. The operator reported an estimated spill of more than 500 BBLs of crude oil in their NRC report, but stated there was limited information available at that time.
- Prior to the discovery of the Failure, the controller of Line 901 noticed anomalies in the operating pressure, shut down and isolated the line around 11:30 am PST, and called field personnel to investigate.
- Another NRC report (No. 1116950) was received by the National Response Center at 12:43 p.m. from the Santa Barbara Dispatch reporting an unknown oil sheen at Refugio Beach.
- The release occurred on the north side of the Pacific Coast Highway. The released product traveled southward through a nearby water drainage culvert approximately ¼ mile to Refugio State Beach, where the product entered the Pacific Ocean. It is estimated that product has spread several miles down the coast.
- The estimated release amount was reported to have increased to 1700 to 2500 BBLs by the Unified Command center on the afternoon of May 20th.

- Refugio State Beach and camp grounds have been closed due to the oil spill. There were no reports of injuries.
- Several areas of environmental sensitivity are located near the Failure Site, including Bell Canyon, Tecolote Canyon, the City of Gaviota, and Coal Oil Point Reserve.
- Various state and federal agencies responded to the scene, including the U.S. Coast Guard, U.S. Environmental Protection Agency, California County Office of Emergency Services, and local fire department(s). Private oil spill response organizations under contract with Plains and Exxon Mobil personnel are also responding. Clean-up operations are underway.
- The cause of the Failure is unknown and the investigation is ongoing.

Determination of Necessity for Corrective Action Order and Right to Hearing:

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, requiring corrective action, which may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or other action, as appropriate. The basis for making the determination that a pipeline facility is or would be hazardous, requiring corrective action, is set forth both in the above-referenced statute and 49 C.F.R. § 190.233, a copy of which is enclosed.

Section 60112 and the regulations promulgated thereunder provide for the issuance of a Corrective Action Order, without prior notice and opportunity for hearing, upon a finding that failure to issue the Order expeditiously would result in the likelihood of serious harm to life, property, or the environment. In such cases, an opportunity for a hearing and expedited review will be provided as soon as practicable after the issuance of the Order.

After evaluating the foregoing preliminary findings of fact, I find that continued operation of the pipeline without corrective measures is or would be hazardous to life, property, or the environment. Additionally, having considered the uncertainties as to the cause of the Failure, the location of the Failure, the material being transported, and the proximity of the pipeline to the Pacific Ocean and environmentally sensitive areas, I find that a failure to issue this Order expeditiously to require immediate corrective action would result in the likelihood of serious harm to life, property, or the environment.

Accordingly, this Corrective Action Order mandating immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

Within 10 days of receipt of this Order, Respondent may contest its issuance and obtain expedited review either by answering in writing or requesting a hearing under 49 C.F.R. § 190.211, to be held as soon as practicable under the terms of such regulation, by notifying the Associate Administrator for Pipeline Safety in writing, with a copy to the Director, Western Region, OPS (Director). If Respondent requests a hearing, it will be held telephonically or in-person in Denver, Colorado, or Washington, D.C.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken on the Affected Pipeline or Plains' Line 903. In that event, PHMSA will notify Respondent of any additional measures that are required and an amended Order will be issued, if necessary. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Actions:

Pursuant to 49 U.S.C. § 60112, I hereby order Plains to immediately take the following corrective actions for the Affected Pipeline:

1. ***Shutdown.*** Plains must not operate the Affected Pipeline until authorized to do so by the Director.
2. ***Empty and Purge the Affected Pipeline.*** Plains must empty and purge the Affected Pipeline and fill with an inert gas until Items 3 through 8 of this Order are completed. This purging must be done as soon as practicable after repairing the Failure Site, but no longer than 10 days after receipt of this Order.
 - a. Plains must notify the Director and local and State responders prior to conducting the purging operations.
 - b. Plains must conduct the purging operations during daylight hours and monitor the pipeline right of way continually to quickly identify and contain any releases should they occur.
3. ***Review of Affected Pipeline.*** Within 45 days of receipt of this Order, Plains must review the Affected Pipeline for conditions similar to those of the Failure. Plains must address any findings that require remedial measures to be implemented prior to restart. This review must include:
 - a. All construction, operating and maintenance (O&M) and integrity management records, such as hydrostatic tests, root cause failure analysis of prior failures, aerial and ground patrols, corrosion protection, One Call tickets, excavations and exposed pipe records, and pipe replacements;
 - b. Identification of all areas of the Affected Pipeline that have insulated pipe and girth welds with "shrink wrap" sleeves;
 - c. All ILI results from the past 10 calendar years, including a followup review of the ILI vendors' raw data and analysis from pre-2015 ILI surveys and a first time review of the data from the ILI survey conducted on May 5, 2015. Determine whether any anomalies were present in the failed pipe joint and any other pipe removed near the Failure Site. Determine whether any anomalies with similar characteristics are present elsewhere on the Affected Pipeline. Plains must submit documentation of this ILI review to the Director within 45 days of receipt of this Order as follows:
 - i. List all ILI tool runs, tool types, and the calendar years of the tool runs conducted on Line 901.
 - ii. Provide all ILI data from the past 10 years to the Director for review by a 3rd party ILI data analyst.

- iii. Explain the process that was used to review the past ILI results, and the process that will be used during the reevaluation.
 - iv. List and describe (type, size, wall loss, etc.) the specific locations of all ILI features from the ILI surveys conducted prior to the May 5, 2015 survey. Include the disposition of those requiring investigation per 49 CFR Part 195.452(h) or Plains's remediation criteria.
 - v. List and describe (type, size, wall loss, etc.) the specific location of all ILI features identified by the May 5, 2015 ILI survey that are present in the failed joint and other pipe removed near the Failure Site.
 - vi. List and describe (type, size, wall loss, etc.) the specific location of all ILI features identified by the May 5, 2015 ILI survey that require investigation per 49 CFR Part 195.452(h) elsewhere on the Affected Pipeline. If an ILI feature or anomaly is identified to be associated with the Failure Site, all features with similar characteristics elsewhere on the Affected Pipeline must be investigated and remediated.
4. **Records Verification.** As recommended in PHMSA Advisory Bulletin 2012-06, Plains must verify the records for the Affected Pipeline to confirm the Maximum Operating Pressure (MOP). Plains must submit documentation of this records verification to the Director within 45 days of receipt of this Order.
 5. **Mechanical and Metallurgical Testing.** Within 45 days of receipt of this Order, complete mechanical and metallurgical testing and failure analysis of the failed pipe, including an analysis of soil samples and any foreign materials. Complete the testing and analysis as follows:
 - a. Document the chain-of-custody when handling and transporting the failed pipe section and other evidence from the Failure Site. The removal and protection of the failed pipe section shall be done in the presence a PHMSA representative, and all failure surfaces shall be protected from damage or contamination during removal and subsequent storage prior to testing.
 - b. Within 10 days of receipt of this Order, develop and submit the testing protocol and the proposed testing laboratory to the Director for prior approval.
 - c. Prior to beginning the mechanical and metallurgical testing, provide the Director with the scheduled date, time, and location of the testing to allow for an OPS representative to witness the testing.
 - d. Ensure the testing laboratory distributes all reports, whether draft or final, in their entirety to the Director at the same time they are made available to Plains.
 6. **Root Cause Failure Analysis.** Within 60 days following receipt of this Order, complete a root cause failure analysis (RCFA) and submit a final report of this RCFA to the Director. The RCFA must be facilitated by an independent third-party acceptable to the Director and must document the decision-making process and all factors contributing to the Failure. The final report must include findings and any lessons learned and whether the findings and any lessons learned are applicable to other locations within Plains' pipeline system.
 7. **Remedial Work Plan.** Within 90 days following receipt of this Order, provide a plan to the Director for his approval to investigate and remediate all actionable anomalies per 49 CFR

Part 195.452(h) and anomalies similar to those that may have led to the release at the Failure site.

8. **Restart Plan.** Prior to resuming operation of the Affected Pipeline, Plains must develop and submit a written Restart Plan to the Director for prior approval.
 - a. The Restart Plan may only be requested after completion of Items 2 through 7 of this Order.
 - b. The Restart Plan must also include documentation of the completion of all mandated actions, and a management of change plan to ensure that all procedural modifications are incorporated into Plains' operations and maintenance procedures manual.
 - c. The Restart Plan must provide for adequate patrolling of the Affected Pipeline during the restart process and must include incremental pressure increases during start-up, with each increment to be held for at least 2 hours.
 - d. The Restart Plan must include sufficient surveillance of the pipeline during each pressure increment to ensure that no leaks are present when operation of the line resumes.
 - e. The Restart Plan must specify a day-light restart and include advance communications with local emergency response officials.
 - f. Once approved by the Director, the Restart Plan will be incorporated by reference into this Order.
9. **Return to Service.** After the Director approves the Restart Plan, Plains may return the Affected Pipeline to service but the operating pressure must not exceed eighty percent (80%) of the actual operating pressure in effect immediately prior to the Failure on May 19, 2015.
10. **Removal of Pressure Restriction.**
 - a. The Director may allow the removal or modification of the pressure restriction upon a written request from Plains demonstrating that restoring the pipeline to its pre-failure operating pressure is justified based on a reliable engineering analysis showing that the pressure increase is safe considering all known defects, anomalies, and operating parameters of the pipeline.
 - b. The Director may allow the temporary removal or modification of the pressure restrictions upon a written request from Plains demonstrating that temporary mitigative and preventive measures are implemented prior to and during the temporary removal or modification of the pressure restriction. The Director's determination will be based on the failure cause and provision of evidence that preventive and mitigative actions taken by the operator provide for the safe operation of the Affected Segment during the temporary removal or modification of the pressure restriction.
11. **Emergency Response Plan and Training Review.** Plains must review and assess the effectiveness of its emergency response plan and Bakersfield Spill Response Plan – Sequence 0107 with regards to the Failure. Include in the assessment a detailed review of the on-scene response and support activities (including timeline), coordination with all parties (including regulatory requests and proceeding with work), site security (including all phases of the response), procedures for improvements, lessons learned, and communication with the National Response Center, emergency responders, third party contractors, public officials, and internal resources. Include a review and assessment of the effectiveness of its emergency training program. Plains must amend its emergency response plan and

emergency training, if necessary, to reflect the results of this review. Documentation of this *Emergency Response Plan and Training Review* must be provided to the Director. Revisions to the Bakersfield Spill Response Plan must be submitted to the Director, Emergency Support and Security Division, for review and approval in accordance with 49 C.F.R. Part 194.

12. **CAO Documentation Report (CDR).** Plains must create and revise, as necessary, a Corrective Action Order Documentation Report (CDR). When Plains has concluded all the items in this Order, the company will submit the final CDR in its entirety to the Director. This will allow the Director to complete a thorough review of all actions taken by Plains according to this Order prior to approving the closure of this Order. The intent is for the CDR to summarize all activities and documentation associated with this Order in one document.
 - a. The Director may approve the CDR incrementally without approving the entire CDR.
 - b. Once approved by the Director, the CDR will be incorporated by reference into this Order.
 - c. The CDR must include but not be limited to:
 - i. Table of Contents;
 - ii. Summary of the Failure and all response activities;
 - iii. Summary of pipe data/properties and all prior assessments of the Affected Pipeline;
 - iv. Summary of all tests, inspections, assessments, evaluations, and analysis required by this Order;
 - v. Summary of the Mechanical and Metallurgical Testing, as required by this Order;
 - vi. Summary of the RCFA with all root causes, as required by this Order;
 - vii. Lessons learned while completing this Order;
 - viii. A path forward describing specific actions Plains will take on its entire pipeline system as a result of the lessons learned from work on this Order

Other Requirements:

1. **Reporting.** Submit monthly reports to the Director that: (1) include all available data and results of the testing and evaluations required by this Order; and (2) describe the progress of the repairs or other remedial actions being undertaken. The first report is due on June 21. The Director may change the interval for the submission of these reports.
2. **Documentation of Costs.** It is requested but not required that Plains maintain documentation of the costs associated with implementation of this Order. Include in each monthly report the to-date total costs associated with: (1) preparation and revision of procedures, studies and analyses; (2) physical changes to pipeline infrastructure, including repairs, replacements and other modifications; and (3) environmental remediation, if applicable.
3. **Approvals.** With respect to each submission requiring the approval of the Director, the Director may: (a) approve the submission in whole or in part; (b) approve the submission

on specified conditions; (c) modify the submission to cure any deficiencies; (d) disapprove the submission in whole or in part and direct Plains to modify the submission; or (e) any combination of the above. In the event of approval, approval upon conditions, or modification by the Director, Plains must proceed to take all actions required by the submission, as approved or modified by the Director. If the Director disapproves all or any portion of a submission, Plains must correct all deficiencies within the time specified by the Director and resubmit it for approval.

4. **Extensions of Time.** The Director may grant an extension of time for compliance with any of the terms of this Order upon a written request timely submitted and demonstrating good cause for an extension.

The actions required by this Corrective Action Order are in addition to and do not waive any requirements that apply to Respondent's pipeline system under 49 C.F.R. Part 195, under any other order issued to Respondent under authority of 49 U.S.C. § 60101, *et seq.*, or under any other provision of Federal or State law. **After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken on the Affected Pipeline or Plains' Line 903.**

Respondent may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.


Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

In your correspondence on this matter, please refer to CPF No. 5-2015-5011H and for each document you submit, please provide a copy in electronic format whenever possible.

The terms and conditions of this Corrective Action Order are effective upon receipt.

MAY 21 2015


Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Date Issued



U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue SE
Washington, DC 20590

JUN 03 2015

VIA CERTIFIED MAIL AND FAX TO: 713-646-4378

Mr. Troy Valenzuela
Vice President EHS
Plains Pipeline, LP
333 Clay Street, Suite 1600
Houston, TX 77002

Re: CPF No. 5-2015-5011H

Dear Mr. Valenzuela:

Enclosed is Amendment No. 1 to the Corrective Action Order issued in the above-referenced case on May 21, 2015. It requires Plains Pipeline, LP to take additional corrective actions with respect to Line 901 and Line 903 of its pipeline system. Service is being made by certified mail and facsimile. Service of the Amendment to the Corrective Action Order by electronic transmission is deemed complete upon transmission and acknowledgement of receipt, or as otherwise provided under 49 C.F.R. § 190.5. The terms and conditions of this Order are effective upon completion of service.

Thank you for your continued cooperation in this matter.

Sincerely,



Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Ms. Linda Daugherty, Deputy Associate Administrator for Field Operations, OPS
Mr. Chris Hoidal, Director, Western Region, OPS

**U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590**

In the Matter of)
)

Plains Pipeline, LP,)
)

Respondent.)
)

CPF No. 5-2015-5011H

AMENDMENT NO. 1 TO THE CORRECTIVE ACTION ORDER

Purpose and Background:

On May 21, 2015, the Associate Administrator issued a Corrective Action Order (CAO) under the authority of 49 U.S.C. § 60112, to require Plains Pipeline, LP (Plains or Respondent), to take certain corrective actions to protect the public, property, and the environment from potential hazards associated with Line 901 (Affected Pipeline) in Santa Barbara County, California. The CAO was issued in response to a May 19, 2015, failure on the Affected Pipeline that caused the release of approximately 1700 to 2500 barrels of heavy crude oil (Failure). The cause of the Failure has not yet been determined. Pursuant to 49 U.S.C. § 60117, the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), initiated an investigation of the accident.

Additional Preliminary Findings:

- The results of Plains' May 5, 2015 In-Line Inspection (ILI) survey revealed four areas on the Affected Pipeline with pipe anomalies requiring immediate investigation and remediation in accordance with 49 CFR § 195.452(h) or Plains' own criteria for investigation under its integrity management plan. Examination and measurements of three of these areas indicated extensive external corrosion, primarily on the bottom quadrant of the pipe. The deepest metal loss at each area, as measured by Plains non-destructive testing contractors, ranged between 54 and 74% of the original pipe wall thickness. The anomalies were not limited to being near the girth welds, but also occurred at other locations along the length of the pipe. The fourth area to be investigated has not yet been completed.

- The Affected Pipeline is experiencing active external corrosion, as follows:

- Plains has reported to PHMSA that the May 5th ILI survey revealed metal loss of approximately 45% of the original wall thickness in the area of the pipe that failed on May 19.
 - PHMSA inspectors noted general external corrosion of the pipe body during field examination of the failed pipe segment.
 - The rupture characteristics at the Failure site indicate a longitudinally oriented opening approximately 6 inches in length and located in the bottom quadrant of the pipe. 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.
 - PHMSA inspectors observed three repairs to the Affected Pipeline in the area near the Failure site that had been made due to external corrosion. These repairs were made after the 2012 ILI survey.
- Plains uses an impressed current cathodic protection (CP) system to protect the Affected Pipeline from external corrosion. After the Failure, PHMSA inspectors witnessed Plains measuring CP levels near the Failure site and at the three anomaly digs that were completed after May 22. The CP levels appeared to be adequate according to 49 CFR § 195.571. External corrosion with CP at this level would not be expected.
 - Plains' Line 903 is a 30-inch diameter pipeline which transports crude oil 128 miles from the Gaviota Pump Station in Santa Barbara County to the Emidio Pump Station in Kern County, California.
 - Plains has informed PHMSA that Line 903 has insulation and shrink wrap sleeves on the girth welds, similar to the Affected Pipeline.
 - Line 903 was completely surveyed by ILI during 2013 and 2014. These ILI results revealed:
 - The 38-mile segment of Line 903 between Gaviota Station and Sisquoc Station was inspected on April 29, 2013, and the report was provided to Plains in June 2013. The ILI vendor reported that this segment had 99 metal loss anomalies requiring investigation.
 - The 75-mile segment of Line 903 between Sisquoc Station and Pentland Station was inspected on June 12, 2013. The report was provided to Plains in August 2013, and a corrected report was provided in September 2013. This segment had no anomalies requiring investigation. However, the ILI vendor reported there were a number of metal loss anomalies that may indicate general corrosion.
 - The 15-mile segment of Line 903 between Pentland Station and Emidio Station was inspected on February 19, 2014, and the report was provided to Plains in May 2014. This segment had no anomalies requiring immediate investigation. However, based on the ILI vendor report, this segment had two girth weld anomalies requiring investigation.
 - The data collected by the ILI surveys for the different segments of Line 903 appear to be inconsistent, requiring immediate review and analysis.

- Plains voluntarily shut down Line 903 on May 19, restarted the line on May 29, and shut the line back down on May 30. Line 903 is currently shut down.

Determination of Necessity for Amendment to the Corrective Action Order and Right to Hearing:

Section 60112 of Title 49, United States Code, provides for the issuance of a Corrective Action Order, after reasonable notice and the opportunity for a hearing, requiring corrective action, which may include the suspended or restricted use of a pipeline facility, physical inspection, testing, repair, replacement, or other action, as appropriate. The basis for making the determination that a pipeline facility is or would be hazardous, requiring corrective action, is set forth both in the above-referenced statute and 49 C.F.R. § 190.233, a copy of which is enclosed.

Section 60112 and the regulations promulgated thereunder provide for the issuance of a Corrective Action Order, without prior notice and opportunity for hearing, upon a finding that failure to issue the Order expeditiously would result in the likelihood of serious harm to life, property, or the environment. In such cases, an opportunity for a hearing and expedited review will be provided as soon as practicable after the issuance of the Order.

After evaluating the preliminary findings in the CAO and the foregoing additional preliminary findings of fact, I find that continued operation of Line 901 and Line 903 without corrective measures is or would be hazardous to life, property, or the environment. Additionally, having considered the uncertainties as to the cause of the Failure, the location of the Failure, the similarities between the characteristics of the Affected Pipeline and Line 903, the material being transported, and the proximity of the pipelines to the Pacific Ocean and environmentally sensitive areas, I find that a failure to issue this Order expeditiously to require immediate corrective action would result in the likelihood of serious harm to life, property, or the environment.

Accordingly, this Amendment to the Corrective Action Order mandating immediate corrective action is issued without prior notice and opportunity for a hearing. The terms and conditions of this Order are effective upon receipt.

The actions required by this Amendment No. 1 to the Corrective Action Order are in addition to the requirements that apply to Respondent's Affected Pipeline under the CAO issued on May 21, 2015.

Within 10 days of receipt of this Amendment, Respondent may contest its issuance and obtain expedited review either by answering in writing or requesting a hearing under 49 C.F.R. § 190.211, to be held as soon as practicable under the terms of such regulation, by notifying the Associate Administrator for Pipeline Safety in writing, with a copy to the Director, Western Region, OPS (Director). If Respondent requests a hearing, it will be held telephonically or in-person in Lakewood, Colorado, or Washington, D.C.

After receiving and analyzing additional data in the course of this investigation, PHMSA may identify other corrective measures that need to be taken on the Affected Pipeline or Plains' Line 903. In that event, PHMSA will notify Respondent of any additional measures that are required

and another Amendment Order will be issued, if necessary. To the extent consistent with safety, Respondent will be afforded notice and an opportunity for a hearing prior to the imposition of any additional corrective measures.

Required Corrective Actions:

Pursuant to 49 U.S.C. § 60112, I hereby order Plains to immediately take the following corrective actions:

With respect to the Affected Pipeline (Line 901):

1. *Paragraph 3(c)(vi) of the Required Corrective Actions of the CAO is amended, in its entirety, as follows:* List and describe (type, size, wall loss, etc.) the specific location of all ILI features identified by the May 5, 2015 ILI survey elsewhere on the Affected Pipeline that require investigation according to 49 CFR § 195.452(h) or the criteria for investigation under Plains' own integrity management plan, whichever is more stringent. All ILI features and anomalies that satisfy the criteria in either 49 CFR § 195.452(h) or the criteria for investigation under Plains' integrity management plan must be investigated and remediated. Provide the Director with a report detailing the results of the investigations and remediations that have been completed, and a proposed schedule for the remaining investigations.
2. ***Non-destructive testing.*** Plains must use a third-party, American Society of Non-Destructive Testing (ASNT) Level III certified, non-destructive testing field contractor to complete a non-destructive testing analysis at the specific location of each ILI feature or anomaly that requires investigation according to 49 CFR § 195.452(h) or the criteria for investigation under Plains' own integrity management plan, whichever is more stringent. If the ILI feature or anomaly is identified as being located at a girth weld with shrink sleeves, the contractor must perform a magnetic particle inspection, or other appropriate technology, of the weld area to check for stress corrosion cracking (SCC). Provide the Director with five business days' notice of the excavation of each pipe section requiring investigation. A summary of the investigations, test results, and remediations must be included in the monthly report required by Item 12 of the CAO, and the test records must be made available for inspection by PHMSA.

With respect to Line 903:

3. ***Pressure Restriction.*** The operating pressure of Line 903 must not exceed eighty percent (80%) of the highest pressure sustained for a continuous 8 hour period between April 19, 2015, and May 19, 2015. This pressure restriction must remain in effect until the Director provides written approval to resume normal operation of Line 903.
4. ***Review of Line 903.*** Within 60 days of receipt of this Amendment, Plains must review Line 903 and address any findings that require remedial measures. This review must include:
 - a. All construction, operating and maintenance (O&M) and integrity management records, such as hydrostatic tests, root cause failure analysis of prior failures, aerial and ground patrols, corrosion protection, One Call tickets, excavations and exposed pipe records, and pipe replacements;

- b. Identification of all areas of Line 903 that have insulated pipe and girth welds with shrink wrap sleeves;
 - c. List and describe (type, size, wall loss, etc.) the specific location of all ILI features identified by the most recent ILI survey that require investigation according to 49 CFR § 195.452(h) or the criteria for investigation under Plains' own integrity management plan, whichever is more stringent. All ILI features and anomalies that satisfy the criteria in either § 195.452(h) or the criteria for investigation under Plains' integrity management plan must be investigated and remediated. Provide the Director with a report detailing the results of the investigations and remediations that have been completed, and a proposed schedule for the remaining anomalies.
5. ***ILI Data for Line 903.*** Plains must provide the following documentation of previous ILI surveys on Line 903 to the Director within 15 days of receipt of this Amendment:
- i. List all ILI tool runs, tool types, and the calendar years of the tool runs conducted on Line 903 over the past 10 calendar years.
 - ii. Provide all ILI data from surveys of Line 903 over the past 10 calendar years to the Director for review by PHMSA's 3rd party ILI data analyst.
6. ***Non-destructive testing.*** Plains must use a third-party, American Society of Non-Destructive Testing (ASNT) Level III certified, non-destructive testing field contractor to complete a non-destructive testing analysis at the specific location of each ILI feature or anomaly on Line 903 identified in Item 4(c) above. If the ILI feature or anomaly is identified to be at a girth weld with shrink sleeves, the contractor must perform a magnetic particle inspection, or other appropriate technology, of the weld area to check for stress corrosion cracking (SCC). Provide the Director with five business days' notice of the excavation of each pipe section requiring investigation. A summary of the investigations, test results, and remediations must be included in the monthly report required by Item 12 of the CAO, and the test records must be made available for inspection by PHMSA.

With respect to both the Affected Pipeline and Line 903:

7. ***Enhanced preventive and mitigative measures.*** Plains must take additional preventive and mitigative measures on the Affected Pipeline and Line 903 while each pipeline is subject to a pressure restriction under the CAO or this Amendment. These measures must include, but are not limited to:
- a. Patrol inspections of surface conditions of the pipeline right-of-way at intervals not exceeding one week;
 - b. Daily inspections of pump stations to identify leaks and abnormal conditions;
 - c. Establishment of pump pressure set points and use of pressure limiting devices to match the required pressure reduction;
 - d. Training of Plains field personnel regarding awareness of abnormal operating conditions that may result from the pressure reduction on the pipeline.
 - e. Plains must maintain all documentation related to the pressure restriction and preventive and mitigative measures, including all inspections, training documents, and management of change (MOC) records.

8. **CAO Documentation Report:** The Corrective Action Order Documentation Report required under Item 12 of the CAO must include a summary of all inspections, assessments, evaluations, and analysis required by this Amendment No. 1 to the CAO.

The actions required by this Amendment No. 1 to the Corrective Action Order are in addition to and do not waive any requirements that apply to Respondent's pipeline system under the CAO, 49 C.F.R. Part 195, under any other order issued to Respondent under authority of 49 U.S.C. § 60101, *et seq.*, or under any other provision of Federal or State law.

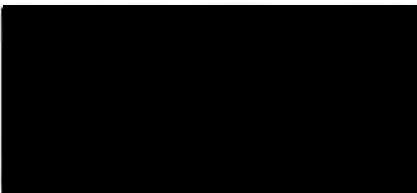
Respondent may appeal any decision of the Director to the Associate Administrator for Pipeline Safety. Decisions of the Associate Administrator shall be final.

Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Failure to comply with this Order may result in the assessment of civil penalties and in referral to the Attorney General for appropriate relief in United States District Court pursuant to 49 U.S.C. § 60120.

In your correspondence on this matter, please refer to CPF No. 5-2015-5011H and for each document you submit, please provide a copy in electronic format whenever possible.

The terms and conditions of this Amendment No. 1 to the Corrective Action Order are effective upon receipt.



Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

June 3, 2015

Date Issued

EXHIBIT D

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19 **UNITED STATES DISTRICT COURT**
 20 **CENTRAL DISTRICT OF CALIFORNIA**

21 UNITED STATES OF AMERICA, and the PEOPLE
 22 OF THE STATE OF CALIFORNIA, *ex rel.*
 23 DEPARTMENT OF FISH AND WILDLIFE,
 24 PEOPLE OF THE STATE OF CALIFORNIA, *ex rel.*
 25 CENTRAL COAST REGIONAL WATER QUALITY
 26 CONTROL BOARD, *ex rel.* CALIFORNIA
 27 DEPARTMENT OF PARKS AND RECREATION, *ex*
 28 *rel.* CALIFORNIA STATE LANDS COMMISSION,
ex rel. CALIFORNIA DEPARTMENT OF
 FORESTRY AND FIRE PROTECTION'S OFFICE
 OF STATE FIRE MARSHAL, and THE REGENTS
 OF THE UNIVERSITY OF CALIFORNIA,

Plaintiffs,

v.

PLAINS ALL AMERICAN PIPELINE, L.P. and
 PLAINS PIPELINE, L.P.,

Defendants.

Civil Action No.
 2:20-cv-02415

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1 A. WHEREAS, on or about May 19, 2015, a hazardous liquid pipeline
2 known as the Line 901 pipeline (“Line 901”) owned and operated by Plains
3 Pipeline, L.P., a wholly owned subsidiary of Plains All American Pipeline, L.P.,
4 (jointly, “Plains” or “Defendants”), failed and discharged approximately 2,934
5 barrels of heavy crude-oil (“Refugio Incident”) in Santa Barbara County,
6 California. A portion of the oil reached the Pacific Ocean and coastal areas such
7 as Refugio State Beach. The Refugio Incident adversely impacted Natural
8 Resources belonging to, managed by, held in trust by, appertaining to, or
9 otherwise controlled by the United States and the State of California
10 (“California” or the “State”).

11 B. WHEREAS, cleanup actions began immediately after the Refugio
12 Incident at the direction of a Unified Command established by the United States
13 Coast Guard (“USCG”) and the State of California Department of Fish and
14 Wildlife (“CDFW”), Office of Spill Prevention and Response (“OSPR”). The
15 Unified Command was comprised of the United States, State agencies, the
16 County of Santa Barbara, and Plains.

17 C. WHEREAS, on May 21, 2015, the United States Department of
18 Transportation’s Pipeline and Hazardous Materials Safety Administration
19 (“PHMSA”) issued Plains a Corrective Action Order (“Original CAO”), CPF No.
20 5-2015-5011H, which was subsequently amended on June 3, 2015 (“CAO
21 Amendment No. 1”), November 12, 2015 (“CAO Amendment No. 2”), and June
22 16, 2016 (“CAO Amendment No. 3”), (collectively, “the PHMSA CAO”). The
23 PHMSA CAO directed Plains, among other things, to purge Line 901 and a
24 portion of the adjoining Line 903 pipeline (“Line 903”), between Plains’ Gaviota
25 and Pentland pump stations, and to keep Line 901 and the purged sections of
26 Line 903 shut down until the actions required by the PHMSA CAO were
27 satisfactorily completed.
28

1 D. WHEREAS, on May 19, 2016, PHMSA issued a Failure
2 Investigation Report, which included PHMSA’s findings of the “proximate or
3 direct” causes and the “contributing” causes of the Refugio Incident.

4 E. WHEREAS, Defendants reimbursed Plaintiffs’ costs incurred for
5 cleanup, and Plaintiffs have no known unreimbursed claims for cleanup costs
6 arising from the Refugio Incident.

7 F. WHEREAS, CDFW incurred certain additional costs arising from
8 the administration and civil enforcement of pollution laws, including attorneys’
9 fees that have been reimbursed by Plains.

10 G. WHEREAS, Plains represents that it has implemented and will
11 continue to utilize an electronic tracking tool and software for maintenance
12 activities, including those activities related to mainline valves. The software
13 tracks which maintenance activities are performed, who performs the activity,
14 when prior notifications of maintenance activities by field personnel are received,
15 when problems requiring maintenance are first discovered, and when
16 maintenance problems are corrected. Plains maintains a separate software
17 program to track the training and qualifications of all maintenance personnel.

18 H. WHEREAS, Plains represents that, following the Refugio Incident
19 and pursuant to PHMSA’s CAO, Plains performed a comprehensive review of its
20 Emergency Response Plan and Training Program, and revised and updated its
21 Response Plan for Onshore Oil Pipelines for Line 901 and Line 903 (“Bakersfield
22 District Response Zone Plan”) to reflect modifications resulting from the review
23 and the incorporation of lessons learned. As part of the revision, Plains identified
24 the locations of culverts along the pipelines’ rights-of-way and provided
25 containment and recovery techniques for responding to spills that may occur near
26 those culverts. Plains provided drafts of the updated Bakersfield District
27 Response Zone Plan to PHMSA, incorporated comments provided by PHMSA,
28 and received approval of the revised plan from PHMSA on September 26, 2017.

1 I. WHEREAS, Plains represents that it also created a more detailed
2 Geographic Information System (“GIS”) based online Tactical Response Plan for
3 its onshore oil pipelines in Southern California, including Line 2000 and the
4 operational portion of Line 903, that, among other things, identifies culverts
5 along the pipelines’ rights-of-way, potential receptors and the equipment,
6 supplies and resources that would be necessary to respond to a spill occurring at
7 any given location along those pipelines, identifies the sources and locations for
8 obtaining those resources, and, in some instances, establishes stored inventories
9 of those resources in specific locations. Plains represents that it intends to keep
10 its Tactical Response Plan updated and available for use in drills and spill
11 response, and that it will make the Tactical Response Plan available to the
12 Plaintiffs upon reasonable request and as needed in connection with a drill or
13 response to a spill.

14 J. WHEREAS, Plains represents that Plains personnel responding to
15 incidents that trigger the standup of an incident command structure (“ICS”) have
16 been provided ICS training appropriate to their responsibilities.

17 K. WHEREAS, the relevant Natural Resources trustees (“Trustees”) for
18 the Refugio Incident are the United States Department of the Interior (“DOI”);
19 United States Department of Commerce, on behalf of the National Oceanic and
20 Atmospheric Administration (“NOAA”); CDFW; California Department of Parks
21 and Recreation (“CDPR”); California State Lands Commission (“CSLC”); and
22 The Regents of the University of California (“UC”).

23 L. WHEREAS, pursuant to Section 1006 of the Oil Pollution Act
24 (“OPA”), 33 U.S.C. 2701, *et seq.*, the United States and the State Trustees
25 allege that oil from the Refugio Incident caused injuries to Natural Resources,
26 including birds, marine mammals, shoreline and subtidal habitats, and also had
27 an impact upon human uses of Natural Resources and other public resources.
28 The Federal Trustees are designated pursuant to the National Contingency Plan,

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1 40 C.F.R. § 300.600 and Executive Order 12777. CDFW and CDPR are
2 designated state trustees pursuant to the National Contingency Plan, 40 C.F.R.
3 § 300.605, and the Governor's Designation of State Natural Resource Trustees
4 pursuant to Section 1006(b)(3) of OPA and the Comprehensive Environmental
5 Response, Compensation and Liability Act of 1980. In addition, CDFW has state
6 natural resource trustee authority pursuant to California Fish and Game Code
7 §§ 711.7 and 1802 and the Lempert-Keene-Seastrand Oil Spill Prevention and
8 Response Act (California Government Code § 8670.1 *et seq.*). CDPR and UC
9 have jurisdiction over natural resources within the state park system and the UC
10 Natural Reserve System, respectively, which are held in trust for the people of
11 the State of California. CSLC is a state trustee pursuant to its jurisdiction under
12 Public Resources Code § 6301 and Civil Code § 670.

13 M. WHEREAS, after the Refugio Incident, the Trustees and Defendants
14 entered into a cooperative Natural Resource Damage Assessment process
15 pursuant to 15 C.F.R. § 990.14, whereby the Trustees and Defendants jointly and
16 independently planned and conducted a number of injury assessment activities.
17 These activities included gathering and analyzing data and other information that
18 the Trustees used to determine and quantify resource injuries and damages. As a
19 result of this process and other activities, the Trustees identified several
20 categories of injured and damaged Natural Resources, including birds, marine
21 mammals, and shoreline and subtidal habitats, as well as effects to human
22 use/recreation resulting from impacts on these Natural Resources, and determined
23 the cost to restore, rehabilitate, replace, or acquire the equivalent of injured
24 Natural Resources. By entering this Consent Decree, Defendants do not admit or
25 agree that the Trustees' NRD findings and determinations are accurate.

26 N. WHEREAS, due to the specific facts surrounding the Refugio
27 Incident, including the timing, degree, and nature of the spill and the affected
28

1 environment, the Trustees will not seek additional damages, costs, or expenses
2 for Natural Resources resulting from the Refugio Incident.

3 O. WHEREAS, Plains agrees to reimburse costs incurred by the
4 Trustees in connection with the NRDA through November 15, 2018, and will not
5 reimburse costs incurred by the Trustees in connection with the NRDA after that
6 date.

7 P. WHEREAS, by entering into this Consent Decree, Plains does not
8 admit the allegations in the Complaint filed in this action, or any liability to the
9 Plaintiffs.

10 Q. WHEREAS, on January 28, 2019, PHMSA initiated a regularly-
11 scheduled “Integrated Inspection” of a portion of Defendants’ Regulated
12 Pipelines, as described below, and other pipeline facilities and records, pursuant
13 to 49 U.S.C. § 60117.

14 R. WHEREAS, the Parties agree that settlement of this matter without
15 further litigation is in the public interest and that the entry of this Consent Decree
16 is the most appropriate means of resolving this action.

17 S. WHEREAS, the Parties agree and the Court by entering this Consent
18 Decree finds, that this Consent Decree: (1) has been negotiated by the Parties at
19 arm’s-length and in good faith; (2) will avoid prolonged litigation between the
20 Parties; (3) is fair and reasonable; and (4) furthers the objectives of the federal
21 and state environmental protections, and the federal and state pipeline safety
22 laws.

23 **I. BACKGROUND**

24 The United States, on behalf of PHMSA, the United States Environmental
25 Protection Agency (“EPA”), DOI, NOAA, and USCG; and the People of the
26 State of California *Ex Relazione* CDFW, CDPR, CSLC, UC, the California
27 Central Coast Regional Water Quality Control Board (“RWQCB”), and the
28 California Department of Forestry and Fire Protection’s - Office of the State Fire

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1 Marshal (“OSFM”), filed a Complaint in this matter pursuant to the Clean Water
2 Act (“CWA”), 33 U.S.C. §§ 1251 *et seq.*, and associated regulations and orders;
3 OPA, 33 U.S.C. §§ 2701 *et seq.*, and associated regulations and orders; the
4 federal Pipeline Safety Laws, 49 U.S.C. §§ 60101 *et seq.*, and associated
5 regulations and orders; the Lempert-Keene-Seastrand Oil Spill Prevention and
6 Response Act, California Government Code §§ 8670.1 *et seq.* and associated
7 regulations; California Fish and Game Code §§ 2014, 5650, 5650.1, 12016,
8 13013; California Water Code §§ 13350, 13385; and the Elder California
9 Pipeline Safety Act of 1981, California Government Code §§ 51010 *et seq.* The
10 Complaint against Plains, *inter alia*, asserts allegations of violations, and seeks
11 penalties, injunctive relief, and Natural Resource Damages.

12 NOW, THEREFORE, before the trial of any claims and without
13 adjudication or admission of any issue of fact or law and with the consent of the
14 Parties, IT IS HEREBY ADJUDGED, ORDERED, AND DECREED as follows:

15 **II. JURISDICTION AND VENUE**

16 1. This Court has jurisdiction over the subject matter of the United
17 States’ claims in this action pursuant to Section 311(b)(7)(E) and (n) of the CWA,
18 33 U.S.C. § 1321(b)(7)(E) and (n), Section 1017(b) of OPA, 33 U.S.C. § 2717(b);
19 Sections 60120 and 60122 of the Pipeline Safety Laws, 49 U.S.C. §§ 60120 and
20 60122; and 28 U.S.C. §§ 1331, 1345, and 1355. This Court has supplemental
21 jurisdiction over the State law claims pursuant to 28 U.S.C. § 1367. To the extent
22 the OPA presentment requirement described in 33 U.S.C. § 2713 applies, the
23 United States and the State Agencies have satisfied the requirement.

24 2. Venue is proper in this District pursuant to Section 311(b)(7)(E) of
25 the CWA, 33 U.S.C. § 1321(b)(7)(E), Section 1017(b) of OPA,
26 33 U.S.C. § 2717(b); Section 60120 of the Pipeline Safety Laws,
27 49 U.S.C. § 60120; and 28 U.S.C. §§ 1391 and 1395(a), because Plains
28

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1 does business in this District and the alleged claims occurred in this District.

2 3. For purposes of this Consent Decree or any action to enforce this
3 Consent Decree, Defendants consent to the Court's jurisdiction over this Consent
4 Decree for such action and Defendants consent to venue in this judicial district.
5 For purposes of this Consent Decree and without admission of liability,
6 Defendants agree that the Complaint states claims upon which relief may be
7 granted.

8 **III. APPLICABILITY**

9 4. Subject to the terms herein, the obligations of this Consent Decree
10 apply to and are binding upon the Parties and any successors, assigns, as well as
11 any other entities or persons otherwise bound by law to comply with this Consent
12 Decree.

13 5. Defendants shall provide a copy of this Consent Decree to all
14 officers, employees, and agents whose duties might reasonably include ensuring
15 compliance with any provision of this Consent Decree, as well as to any
16 contractor retained for the purpose of performing work required under this
17 Consent Decree. Defendants shall condition any such contract upon performance
18 of the work in conformity with the terms of this Consent Decree by specifying
19 that contractors are obligated to perform work in compliance with this Consent
20 Decree.

21 6. In any action to enforce this Consent Decree, Defendants shall not
22 raise as a defense the failure by any of their officers, directors, employees,
23 agents, or contractors to take any actions necessary to comply with the provisions
24 of this Consent Decree.

25 **IV. DEFINITIONS**

26 7. Terms used in this Consent Decree that are defined in the CWA,
27 OPA, Pipeline Safety Laws, the Lempert-Keene-Seastrand Oil Spill Prevention
28 and Response Act, and the Elder California Pipeline Safety Act of 1981 shall

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1 have the meanings assigned to them in these statutes and their regulations, unless
2 otherwise provided in this Consent Decree. Whenever the terms set forth below
3 are used in this Consent Decree, the following definitions shall apply:

4 “Appendix A” is the set of maps that generally depict Lines 901, 903, and
5 2000;

6 “Appendix B” is the Injunctive Relief that Plains is required to perform
7 under this Consent Decree;

8 “Appendix C” is intentionally left blank;

9 “Appendix D” is the list of remaining corrective actions from the PHMSA
10 CAO that Plains is still required to implement under this Consent Decree. For
11 the terms of the PHMSA CAO, *see*
12 [https://primis.phmsa.dot.gov/comm/reports/enforce/CaseDetail_cpf_520155011H](https://primis.phmsa.dot.gov/comm/reports/enforce/CaseDetail_cpf_520155011H.html?nocache=4888#_TP_1_tab_1)
13 [.html?nocache=4888#_TP_1_tab_1](https://primis.phmsa.dot.gov/comm/reports/enforce/CaseDetail_cpf_520155011H.html?nocache=4888#_TP_1_tab_1);

14 “CDFW” shall mean the California Department of Fish and Wildlife and
15 any of its successor departments or agencies;

16 “CDPR” shall mean the California Department of Parks and Recreation
17 and any of its successor departments or agencies;

18 “Complaint” shall mean the Complaint filed by the Plaintiffs in this action;

19 “Consent Decree” shall mean this Consent Decree and all Appendices
20 attached hereto;

21 “Control Room Management Plan” shall mean Plains’ Control Room
22 Management Plan, dated October 2019, and delivered to PHMSA electronically
23 on October 21, 2019, from counsel for Defendants;

24 “Control Center General Procedures” shall mean Plains’ Control Center
25 General Procedures, dated October 2019, and delivered to PHMSA electronically
26 on October 21, 2019, from counsel for Defendants;

27 “CSLC” shall mean the California State Lands Commission and any of its
28 successor departments or agencies;

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1 “Day” shall mean a calendar day unless expressly stated to be a working
2 day. In computing any period of time under this Consent Decree, the rules set
3 forth in Rule 6 of the Federal Rules of Civil Procedure shall apply;

4 “Defendants” shall mean Plains All American Pipeline, L.P. and Plains
5 Pipeline, L.P.;

6 “Delivery Lines” as stated in Appendix B shall mean any pipeline that
7 generally operates to move oil from a delivery meter on a pipeline or facility to
8 another pipeline or facility in close proximity;

9 “DOI” shall mean the United States Department of the Interior, including
10 its bureaus and agencies, and any of its successor departments or agencies;

11 “Elder California Pipeline Safety Act” shall mean the Elder California
12 Pipeline Safety Act of 1981, California Government Code §§ 51010 *et seq.*;

13 “EPA” shall mean the United States Environmental Protection Agency and
14 any of its successor departments or agencies;

15 “Effective Date” shall have the definition provided in Section XXI
16 (Effective Date);

17 “Federal Trustees” shall mean DOI and NOAA in their capacities as
18 Natural Resource Trustees;

19 “Integrity Management Plan” or “IMP” shall mean Plains’ Integrity
20 Management Plan, dated September 2019, as delivered to PHMSA by letter dated
21 November 19, 2019, from counsel for Defendants;

22 “Line 901” is Defendants’ 24-inch diameter crude-oil pipeline that
23 extends approximately 10.7 miles in length from the Los Flores Pump Station to
24 the Gaviota Pump Station, in Santa Barbara County, California, as generally
25 depicted in Appendix A;

26 “Line 903” is Defendants’ 30-inch diameter crude-oil pipeline that extends
27 approximately 129 miles in length from the Gaviota Pump Station in Santa
28 Barbara County, California to the Emidio Pump Station in Kern County,

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1 California, with intermediate stations at Sisquoc Mile Post 38.5 and Pentland
2 Mile Post 114.57, as generally depicted in Appendix A;

3 “Line 2000” is Defendants’ 20-inch diameter pipeline that extends
4 approximately 130 miles in length and transports crude-oil produced in the outer
5 continental shelf and the San Joaquin Valley. Line 2000 runs from Bakersfield,
6 California, over the Tehachapi Mountains and through the Grapevine I-5 corridor
7 and extends to delivery locations in the Los Angeles metropolitan area, as
8 generally depicted in Appendix A;

9 “Mainline pipeline” as stated in Appendix B shall mean the principal
10 pipeline or the parallel pipeline in a given pipeline system, excluding connected
11 lateral lines or branch lines that are used locally to deliver product either into the
12 mainline pipeline from, or out of the mainline pipeline to, a nearby facility or a
13 third-party line;

14 “Natural Resource” and “Natural Resources” shall mean land, fish,
15 mammals, birds, wildlife, biota, air, water, ground water, drinking water supplies,
16 and other such resources belonging to, managed by, held in trust by, appertaining
17 to, or otherwise controlled by the United States and/or the State or any
18 subdivision thereof, and shall also mean the services provided by such resources
19 to other resources or to humans;

20 “Natural Resource Damages” or “NRD” shall mean all damages, including
21 restoration or rehabilitation costs, recoverable by the United States or State
22 Trustees for injuries to, destruction of, loss of, or loss of use of, natural resources
23 including any services such natural resources provide, including the reasonable
24 costs of assessing the damage, as described in 33 U.S.C. § 2702(b)(2)(A),
25 resulting from the Refugio Incident;

26 “Natural Resource Damage Assessment” or “NRDA” shall mean the
27 process of collecting, compiling, and analyzing information, statistics, or data
28 through prescribed methodologies to determine damages for injuries to Natural

1 Resources, as described in 15 C.F.R. Part 990, resulting from the Refugio
2 Incident;

3 “NRD Payment” shall mean the payment Defendants are required to pay
4 for the Natural Resource Damages as described in Section VI (Natural Resource
5 Damages);

6 “Natural Resource Trustees” or “Trustees” are those federal and state
7 agencies or officials designated or authorized pursuant to the CWA, OPA, and/or
8 applicable state laws to act as Trustees for the Natural Resources belonging to,
9 managed by, controlled by, or appertaining to the United States or the State.

10 Participating Trustees in the Natural Resource Damage Assessment and in this
11 Consent Decree are DOI, NOAA, CDFW, CDPR, CSLC, and UC;

12 “NOAA” shall mean the National Oceanic and Atmospheric
13 Administration and any of its successor departments or agencies;

14 “Oil Spill Liability Trust Fund” or “OSLTF” shall mean, *inter alia*, the
15 fund established pursuant to 26 U.S.C. § 9509, including the claim-
16 reimbursement provisions set forth in 33 U.S.C. § 2712;

17 “OSFM” shall mean the California Department of Forestry and Fire
18 Protection’s - Office of the State Fire Marshal and any of its successor
19 departments or agencies;

20 “Paragraph” shall mean a portion of this Consent Decree identified by an
21 Arabic numeral;

22 “Parties” shall mean the Plaintiffs and Defendants, collectively;

23 “PHMSA” shall mean the United States Department of Transportation,
24 Pipeline and Hazardous Materials Safety Administration and any of its successor
25 departments or agencies;

26 “PHMSA Corrective Action Order” or “PHMSA CAO” shall mean the
27 Original CAO issued on May 21, 2015, by PHMSA, which was subsequently
28 amended on June 3, 2015, November 12, 2015, and June 16, 2016;

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1 “Pipeline Safety Laws” shall mean 49 U.S.C. §§ 60101 *et seq.*, and
2 regulations promulgated thereunder, including 49 C.F.R. Parts 190-199;

3 “Plaintiffs” shall mean the United States and the State Agencies;

4 “Refugio Incident” shall mean the release of approximately 2,934 barrels
5 of crude-oil from Plains’ Line 901 Pipeline, in Santa Barbara County, California
6 on or about May 19, 2015;

7 “Regulated Pipeline” shall mean any pipeline operated by Plains subject to
8 regulation under 49 C.F.R. Subchapter D, 19 California Code of Regulations Div.
9 1 Ch. 14, or the pipeline safety regulations of any other state certified by PHMSA
10 pursuant to 49 U.S.C. § 60105, but excludes facilities other than pipelines;

11 “Requests for Information” or “RFI” shall mean PHMSA’s RFIs dated
12 August 19, 2015, August 21, 2015, and September 1, 2016. RFIs shall also refer
13 to PHMSA’s subpoenas issued to Plains dated July 27, 2016 and June 2, 2017;

14 “Restore” or “Restoration” shall mean any action or combination of actions
15 to restore, rehabilitate, replace or acquire the equivalent of any Natural Resource
16 and its services, including Natural Resource-based recreational opportunities that
17 were injured, lost, or destroyed as a result of the Refugio Incident;

18 “RWQCB” shall mean the California Central Coast Regional Water
19 Quality Control Board and any of its successor departments or agencies;

20 “Section” shall mean a portion of this Consent Decree identified by a
21 Roman numeral;

22 “Segment” as stated in Appendix B shall mean any contiguous portion of a
23 pipeline system for which a single hydrostatic test or ILI may be performed, as
24 determined by Defendants;

25 “State Agencies” shall mean the People of the State of California, *Ex*
26 *Relatione* CDFW, CDPR, CSLC, OSFM, RWQCB, and UC. The State Agencies
27 do not include any entity or political subdivision of the State of California other
28 than those agencies herein designated the “State Agencies”;

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1 “State Trustees” shall mean CDFW, CDPR, CSLC, and UC in their
2 capacities as Natural Resource Trustees;

3 “United States” shall mean the United States of America, on behalf of
4 PHMSA, EPA, DOI, NOAA, and USCG;

5 “UC” shall mean The Regents of the University of California and any of its
6 successor departments or agencies; and

7 “USCG” shall mean the United States Coast Guard and any of its
8 successor departments or agencies.

9 **V. CIVIL PENALTIES**

10 A. Within thirty (30) Days after the Effective Date, Defendants shall pay to
11 the United States, CDFW, and RWQCB a total civil penalty of twenty-four
12 million dollars (\$24,000,000), together with interest accruing from the date on
13 which the Consent Decree is lodged with the Court, at a rate specified in 28
14 U.S.C. § 1961 (the “Penalty Payment”). The Penalty Payment shall be allocated
15 as follows:

16 8. Penalty Payment to the United States (PHMSA). For violations of
17 the Pipeline Safety Laws alleged in the United States’ Complaint, Defendants
18 shall pay to the United States a civil penalty of fourteen million five hundred
19 thousand dollars (\$14,500,000), together with a proportionate share of the interest
20 accrued on the Penalty Payment. The Penalty Payment shall be made as follows:

21 a. Thirteen million two hundred fifty thousand dollars
22 (\$13,250,000) attributed to Plains’ alleged Pipeline Safety Law
23 violations; and

24 b. One million two hundred fifty thousand dollars (\$1,250,000)
25 attributed to Plains’ alleged non-compliance with the RFIs.

26 c. Payment shall be made by FedWire Electronic Funds Transfer
27 (“EFT”) to the United States Department of Justice in accordance
28 with written instructions to be provided to Defendants by the

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1 Financial Litigation Unit (“FLU”) of the United States Attorney’s
2 Office for the Central District of California Western Division after
3 the Effective Date. The payment instructions provided by the FLU
4 will include a Consolidated Debt Collection System (“CDCS”)
5 number, which Defendants shall use to identify all payments
6 required to be made in accordance with this Consent Decree. The
7 FLU will provide the payment instructions to:

8 Megan Prout
9 Senior Vice President
10 Commercial Law and Litigation
11 Plains All American Pipeline, L.P.
12 333 Clay Street, Suite 1600
Houston, TX 77002

13 on behalf of Defendants. Defendants may change the individual to
14 receive payment instructions on their behalf by providing written
15 notice of such change to the United States in accordance with
16 Section XX (Notices).

17 d. At the time of payment, Defendants shall send a copy of the
18 EFT authorization form and the EFT transaction record, together
19 with a transmittal letter, which shall state the payment is for the civil
20 penalty owed pursuant to this Consent Decree in the *United States of*
21 *America and the People of the State of California v. Plains All*
22 *American Pipeline, L.P., et al.*, and shall reference the Civil Action
23 Number assigned to this case, CDCS Number, and DOJ case number
24 90-5-1-1-11340, to the United States in accordance with Section XX
25 (Notices).

26 9. Penalty Payment to the United States (EPA) shared with CDFW and
27 RWQCB. The Penalty Payment shall be allocated as follows:

28 a. As a CWA penalty for violations of 33 U.S.C. § 1321(b) and

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1 the California statutes alleged in the Complaint other than California
2 Government Code § 8670.66(b), Defendants shall pay a civil penalty
3 of nine million four hundred fifty thousand dollars (\$9,450,000),
4 together with a proportionate share of the interest accrued on the
5 Penalty Payment. The Penalty Payment shall be made as follows:

6 1) To CDFW, one million twenty-five thousand dollars
7 (\$1,025,000), together with a proportionate share of the
8 interest accrued on the Penalty Payment. The Penalty
9 Payment shall be made by check payable to California
10 Department of Fish and Wildlife. The check shall be sent by
11 overnight or certified mail to:

12 California Department of Fish and Wildlife
13 Office of Spill Prevention and Response
14 Attn: Katherine Verrue-Slater, Senior Counsel
15 P.O. Box 160362
16 Sacramento, California 95816-0362

17 The check shall reference the “Refugio Oil Spill.” CDFW
18 shall deposit the money as follows: one million dollars
19 (\$1,000,000) into the Environmental Enhancement Fund
20 pursuant to California Government Code § 8670.70; and
21 twenty-five thousand dollars (\$25,000) into the Fish and
22 Wildlife Pollution Account pursuant to California Fish and
23 Game Code §§ 12017 and 13011.

24 2) To RWQCB, two million five hundred thousand dollars
25 (\$2,500,000), together with a proportionate share of the
26 interest accrued on the Penalty Payment. The Penalty
27 Payment shall be made by check payable to the “State Water
28 Pollution Cleanup and Abatement Account” and sent to:

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1 State Water Resources Control Board
2 Division of Administrative Services, ATTN: Civil
3 Liability Payment
4 P.O. Box 1888
5 Sacramento, California 95812-1888

6 The check shall reference the “Refugio Oil Spill.”

7 3) To the United States, five million nine hundred twenty-
8 five thousand dollars (\$5,925,000), together with a
9 proportionate share of the interest accrued on the Penalty
10 Payment, by EFT to the United States Department of Justice, in
11 accordance with instructions to be provided to Defendants by
12 the FLU of the United States Attorney’s Office for the Central
13 District of California Western Division. Such monies are to be
14 deposited in the OSLTF. The Penalty Payment shall reference
15 the Civil Action Number assigned to this case, DOJ case
16 number 90-5-1-1-11340, and USCG reference numbers FPNs
17 A15017 and A15018, and shall specify that the payment is
18 made for CWA civil penalties to be deposited into the OSLTF
19 pursuant to 33 U.S.C. § 1321(s), Section 4304 of Pub. L. No.
20 101-380, and 26 U.S.C. § 9509(b)(8). Any funds received after
21 11:00 a.m. Eastern Standard Time shall be credited on the next
22 business day. Defendants shall simultaneously provide notice
23 of payment in writing, together with a copy of any transmittal
24 documentation to EPA and the United States in accordance with
25 Section XX (Notices) of this Consent Decree, and to EPA by
26 email to acctsreceivable.CINWD@epa.gov and to EPA and the
27 National Pollution Funds Center at the following addresses:
28

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1 U.S. Environmental Protection Agency
2 Cincinnati Finance Office
3 26 Martin Luther King Drive
4 Cincinnati, Ohio 45268

5 and

6 Patricia V. Kingcade
7 Attorney Advisor
8 National Pollution Funds Center
9 U.S. Coast Guard
10 2703 Martin Luther King Jr. Avenue SE
11 Washington, D.C. 20593-7605

12 10. Penalty Payment to be Paid to CDFW. For alleged violations of
13 California Government Code § 8670.25.5, Defendants shall pay a civil penalty
14 pursuant to California Government Code § 8670.66(b) of fifty thousand dollars
15 (\$50,000) together with a proportionate share of the interest accrued on the
16 Penalty Payment. The Penalty Payment shall be made by check payable to
17 California Department of Fish and Wildlife. The check shall be sent by overnight
18 or certified mail to:

19 California Department of Fish and Wildlife
20 Office of Spill Prevention and Response
21 Attn: Katherine Verrue-Slater, Senior Counsel
22 P.O. Box 160362
23 Sacramento, California 95816-0362

24 The check shall reference the “Refugio Oil Spill.” CDFW shall deposit the
25 money into the Environmental Enhancement Fund pursuant to California
26 Government Code § 8670.70.

27 11. Defendants shall not deduct or capitalize any penalties paid under
28 this Section or under Section XI (Stipulated Penalties) in calculating their federal
or state income taxes.

VI. NATURAL RESOURCE DAMAGES

12. Within thirty (30) Days after the Effective Date, Defendants shall
pay an NRD Payment of twenty-two million three hundred twenty-five thousand

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1 dollars (\$22,325,000) together with interest accruing from November 16, 2018, at
2 a rate specified in 28 U.S.C. § 1961. The NRD Payment shall be allocated as
3 follows:

4 a. To DOI, eighteen million four hundred twenty-two thousand
5 dollars (\$18,422,000) together with a proportionate share of the
6 interest accrued on the NRD Payment. Such payment shall be used
7 by the Trustees for the purposes set forth in Section VII (Trustees'
8 Management and Applicability of Joint NRD Funds). Defendants
9 shall make such payment by EFT to the United States Department of
10 Justice in accordance with instructions that the FLU of the United
11 States Attorney's Office for the Central District of California
12 Western Division shall provide to Defendants following the
13 Effective Date of this Consent Decree by this Court. At the time of
14 payment, Defendants shall simultaneously send written notice of
15 payment and a copy of any transmittal documentation to the
16 Trustees in accordance with Section XX (Notices) of this Consent
17 Decree and to:

18 Department of the Interior
19 Natural Resource Damage Assessment and
20 Restoration Program
21 Attention: Restoration Fund Manager
22 1849 "C" Street, N.W. Mail Stop 4449
23 Washington, D.C. 20240

24 The EFT and transmittal documentation shall reflect that the
25 payment is being made to the Department of the Interior Natural
26 Resources Damage Assessment and Restoration Fund ("Restoration
27 Fund"), Account Number 14X5198. DOI will maintain these funds
28 as a segregated subaccount named REFUGIO BEACH OIL SPILL
NRD Subaccount within the Restoration Fund.

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1 b. To CDPR, two million eighty-four thousand dollars
2 (\$2,084,000) together with a proportionate share of the interest
3 accrued on the NRD Payment, for deposit into the State Park
4 Contingent Fund. Payment shall be made by check payable to the
5 California Department of Parks and Recreation. At the time of
6 payment, Defendants shall simultaneously send written notice of
7 payment and a copy of any transmittal documentation to the
8 Trustees in accordance with Section XX (Notices) of this Consent
9 Decree. The check shall be sent by overnight or certified mail to:

10 The California Department of Parks and
11 Recreation
12 Attn: Laura Reimche, Senior Counsel
13 1416 Ninth Street, Room 1404-6
 Sacramento, California 95814

14 The check shall reference the “Refugio Beach Oil Spill” and reflect
15 that it is a payment to the State Parks Contingent Fund. CDPR shall
16 use such monies to fund appropriate projects within State Parks’
17 properties from Gaviota to El Capitan State Park to compensate for
18 recreation losses resulting from the Refugio Incident. CDPR shall
19 manage such monies in accordance with Section VIII (Trustees’
20 Management of Recreational Use Funds).

21 c. To the National Fish and Wildlife Foundation (“NFWF”), one
22 million seven hundred ninety-three thousand dollars (\$1,793,000)
23 together with a proportionate share of the interest accrued on the
24 NRD Payment, on behalf of the State Trustees for deposit into the
25 California South Coast Shoreline Parks and Outdoor Recreational
26 Use Account established by NFWF. Payment shall be made by
27 check payable to the National Fish and Wildlife Foundation. At the
28 time of payment, Defendants shall simultaneously send written

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1 notice of payment and a copy of any transmittal documentation to
2 the Trustees in accordance with Section XX (Notices) of this
3 Consent Decree. The check shall be sent by overnight or certified
4 mail to:

5 California Department of Fish and Game
6 Office of Spill Prevention and Response
7 Attn: Katherine Verrue-Slater, Senior Counsel
8 P.O. Box 160362
9 Sacramento, California 95816-0362

10 The check shall reference the “Refugio Beach Oil Spill” and reflect
11 that it is a payment to the California South Coast Shoreline Parks
12 and Outdoor Recreational Use Account. The California South Coast
13 Shoreline Parks and Outdoor Recreational Use Account shall be
14 managed in accordance with the South Coast Shoreline Parks and
15 Outdoor Recreational Use Account Memorandum of Agreement
16 among the State Trustees and NFWF and shall be used by the
17 Trustees for the purposes set forth in Section VIII (Trustees’
18 Management of Recreational Use Funds).

19 d. To UC, twenty-six thousand dollars (\$26,000) together with a
20 proportionate share of the interest accrued on the NRD Payment, for
21 deposit into Natural Reserve System Account. Payment shall be
22 made by check payable to The Regents of the University of
23 California. At the time of payment, Defendants shall simultaneously
24 send written notice of payment and a copy of any transmittal
25 documentation to the Trustees in accordance with Section XX
26 (Notices) of this Consent Decree. The check shall be sent by
27 overnight or certified mail to:
28

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1 The Regents of the University of California
2 Attn: Michael Kisgen, Associate Director
3 Natural Reserve System
4 University of California, Office of the President
5 1111 Franklin Street, 6th Floor
6 Oakland, California 94607-5200

7 The check shall reference the “Refugio Beach Oil Spill” and reflect
8 that it is a payment to the Natural Reserve System Account. The
9 University of California Natural Reserve System will administer the
10 monies to fund projects selected by the University of California in
11 coordination with the Trustees. The projects shall address the
12 research, education, and outreach missions of the University of
13 California. UC shall manage such monies in accordance with
14 Section VIII (Trustees’ Management of Recreational Use Funds).

15 13. The NRD Payment is in addition to the NRDA costs incurred by the
16 Trustees through November 15, 2018, which have been separately reimbursed by
17 Defendants. To date, Plains has paid approximately ten million dollars
18 (\$10,000,000) for NRDA costs incurred by the Trustees through November 15,
19 2018.

20 **VII. TRUSTEES’ MANAGEMENT AND APPLICABILITY OF JOINT**
21 **NRD FUNDS**

22 14. DOI shall, in accordance with law, manage and invest funds in the
23 REFUGIO BEACH OIL SPILL NRD Subaccount, paid pursuant to Paragraph
24 12, and any return on investments or interest accrued on the REFUGIO BEACH
25 OIL SPILL NRD Subaccount for use by the Natural Resource Trustees in
26 connection with Restoration of Natural Resources affected by the Refugio
27 Incident. DOI shall not make any charge against the REFUGIO BEACH OIL
28 SPILL NRD Subaccount for any investment or management services provided.

15. DOI shall hold all funds in the REFUGIO BEACH OIL SPILL NRD

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1 Subaccount, including return on investments or accrued interest, subject to the
2 provisions of this Consent Decree.

3 16. The Natural Resource Trustees commit to the expenditure of the
4 funds set forth in Paragraph 12 for the design, implementation, permitting (as
5 necessary), monitoring, and oversight of Restoration projects and for the costs of
6 complying with the requirements of the law to conduct a Restoration planning
7 and implementation process. The Natural Resource Trustees will use the funds to
8 Restore, rehabilitate, replace or acquire the equivalent of any Natural Resource
9 and its services, including lost human use of such services, injured, lost, or
10 destroyed as a result of the Refugio Incident and for the administration and
11 oversight of these Restoration projects.

12 17. The specific projects or categories of projects will be contained in a
13 Restoration Plan prepared and implemented jointly by the Trustees, for which
14 public notice, opportunity for public input, and consideration of public comment
15 will be provided. Plains shall have no responsibility nor liability for
16 implementation of the Restoration Plan or projects relating to the Refugio
17 Incident, including any future project costs other than the payments set forth in
18 Section VII herein. The Trustees jointly retain the ultimate authority and
19 responsibility to use the funds in the REFUGIO BEACH OIL SPILL NRD
20 Subaccount to Restore Natural Resources in accordance with applicable law, this
21 Consent Decree, and any memorandum or other agreement among them.

22 **VIII. TRUSTEES' MANAGEMENT OF RECREATIONAL USE**
23 **FUNDS**

24 18. CDPR shall allocate the monies paid pursuant to Paragraph 12 for
25 projects providing human use benefits and for the oversight of those projects in
26 accordance with a Restoration Plan prepared and implemented jointly by the
27 Trustees, this Consent Decree, and in accordance with applicable law and any
28 Trustee memorandum or other agreement among them.

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1 4) Section 11.3, “Conducting Preventive and Mitigative
2 Evaluation Meetings;”

3 5) Section 11.4, “Documentation of P&M Evaluation
4 Meetings;” and

5 6) Section 11.6, “Implementation of P&M
6 Recommendations.”

7 For purposes of this Paragraph, the term “material change” refers to
8 any substantive modification in the IMP Procedures that could affect
9 the outcome or effect of a particular procedure or requirement.

10 b. At least thirty (30) Days prior to making a material change to
11 the above sections of the IMP, Defendants shall provide written
12 notice to PHMSA that includes a copy of the proposed change(s). In
13 the event PHMSA provides a written objection to Defendants’ notice
14 prior to the effective date of the material change and they cannot
15 informally resolve the matter, Defendants shall have the right to
16 submit the issue to Dispute Resolution (Section XIII).

17 c. In the event Plains cannot reasonably provide the thirty (30)
18 Day notice of material modification to the IMP described in
19 Subparagraph 22.b due to an unanticipated emergency, Plains shall
20 provide written notice to PHMSA within seven (7) Days of the
21 material change, stating the basis for the abbreviated notice. In the
22 event PHMSA provides a written objection to Defendants’
23 modification, Defendants shall have the right to submit the issue to
24 Dispute Resolution (Section XIII).

25 d. In the event PHMSA provides a written objection to a
26 material modification of Defendants’ IMP, PHMSA and Defendants
27 shall have sixty (60) Days for informal consultation. The parties
28 may mutually agree to extend the period by no more than thirty (30)

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1 Days. Following the notice period specified in Subparagraphs 22.b
2 and 22.c, Defendants may implement the modification until the
3 dispute is resolved. If the dispute is not resolved as a result of the
4 informal consultation, PHMSA or Defendants may invoke Dispute
5 Resolution pursuant to Section XIII. Stipulated penalties shall not
6 accrue during the informal consultation period described in this
7 Paragraph.

8 23. Material Changes in Control Room Management Plan and Control
9 Center General Procedures.

10 a. Plains' Control Room Management Plan and Control Center
11 General Procedures (collectively, "Control Center Plan and
12 Procedures") shall serve as the baseline Control Center Plan and
13 Procedures for purposes of this Consent Decree. Plains agrees that it
14 will not make any material changes to sections 6.5.5, 6.6.8, 8, 9.6.4,
15 9.6.9, 9.6.13, and 9.6.14 of its Control Room Management Plan and
16 procedures 100-2, 100-8, 100-9, 200-1, 300-1, 300-3, 300-5, 400-0,
17 and 500-12 of its Control Center General Procedures throughout the
18 term of this Consent Decree without following the process set forth
19 in this Paragraph. For purposes of this Paragraph, the term "material
20 change" refers to any substantive modification in the Control Center
21 Plan and Procedures that could affect the outcome or effect of a
22 particular procedure or requirement.

23 b. At least thirty (30) Days prior to making a material
24 modification to the above sections of its Control Room
25 Management Plan and Control Center General Procedures,
26 Defendants shall provide written notice to PHMSA that includes a
27 copy of the proposed change(s). In the event PHMSA provides a
28 written objection to Defendants' notice prior to the effective date of

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1 the material change(s), Defendants shall have the right to submit the
2 issue to Dispute Resolution (Section XII).

3 c. In the event Plains cannot reasonably provide the thirty (30)
4 Day notice of material modification to the Control Room
5 Management Plan and Control Center General Procedures described
6 in Subparagraph 23.b due to an unanticipated emergency, Plains
7 shall provide written notice to PHMSA within seven (7) Days of the
8 material modification, stating the basis for the abbreviated notice. In
9 the event PHMSA provides a written objection to Defendants'
10 modification, Defendants shall have the right to submit the issue to
11 Dispute Resolution (Section XIII).

12 d. In the event PHMSA provides a written objection to a
13 material modification of Defendants' Control Room Management
14 Plan and Control Center General Procedures, PHMSA and
15 Defendants shall have sixty (60) Days for informal consultation.
16 The parties may mutually agree to extend the period by no more
17 than thirty (30) Days. Following the notice period specified in
18 Subparagraphs 23.b and 23.c, Defendants may implement the
19 modification until the dispute is resolved. If the dispute is not
20 resolved as a result of the informal consultation, PHMSA or
21 Defendants may invoke Dispute Resolution pursuant to Section XIII.
22 Stipulated penalties shall not accrue during the informal consultation
23 period described in this Paragraph.

24 24. Where any compliance obligation under this Consent Decree requires
25 Defendants to obtain a federal, state, or local permit or approval, Defendants shall
26 submit timely applications and take all other actions reasonably necessary to obtain
27 all such permits or approvals. Defendants may seek relief under the provisions of
28 Section XII (Force Majeure) for any delay in the performance of any such

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1 obligation resulting from a failure to obtain, or a delay in obtaining, any permit or
2 approval required to fulfill such obligation, if Defendants have submitted timely
3 applications and have taken all other actions reasonably necessary to obtain all
4 such permits or approvals.

5 **X. CORRECTIVE ACTION ORDER**

6 25. Upon the Effective Date of this Consent Decree, the PHMSA CAO
7 shall close and be of no further force or effect. All outstanding terms and
8 obligations under the PHMSA CAO as of the Effective Date and which Plains is
9 still required to implement under this Consent Decree are set forth in Appendix D.

10 **XI. STIPULATED PENALTIES**

11 26. Unless excused under Section XII (Force Majeure), Defendants shall
12 be liable for stipulated penalties for violations of this Consent Decree as specified
13 below. A violation includes failing to perform any obligation required by the
14 terms of this Consent Decree according to all applicable requirements of this
15 Consent Decree and within the specified time schedules established by or
16 approved under this Consent Decree.

17 27. Late Payment of Civil Penalties and NRD Payment.

18 a. If Defendants fail to pay any portion of the Penalty Payment
19 to the United States required under Section V (Civil Penalties) when
20 due, Defendants shall pay to the United States a stipulated penalty of
21 ten thousand dollars (\$10,000) per Day for each Day payment is
22 late.

23 b. If Defendants fail to pay any portion of the Penalty Payment
24 to the CDFW and/or RWQCB as required under Section V (Civil
25 Penalties) when due, Defendants shall pay to the CDFW and/or
26 RWQCB a stipulated penalty of ten thousand dollars (\$10,000) each,
27 as applicable, per Day for each Day payment is late.

28 c. If Defendants fail to pay any portion of the NRD Payments

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1 required under Section VI (Natural Resource Damages) when due,
2 Defendants shall pay a stipulated penalty of five thousand dollars
3 (\$5,000) to the United States, and five thousand dollars (\$5,000) to
4 the State Trustees, per Day for each Day payment is late.

5 28. Stipulated Penalties for Non-Performance of Injunctive Relief.

6 Unless excused under Section XII (Force Majeure), the stipulated penalties
7 described in this Paragraph shall accrue per violation per Day for Defendants'
8 failure to perform the following injunctive relief required under Section IX
9 (Injunctive Relief) when due:

- 10 a. For failure to timely submit to OSFM the applications for
11 State waivers as specified in paragraphs 1.A, 1.B, 1.C, and 1.D of
12 Appendix B;
- 13 b. For failure to implement the Integrity Management provisions
14 as specified in paragraphs 4.A.1.a, e, f, g, h, and 4.A.2 of Appendix
15 B;
- 16 c. For failure to timely submit to OSFM the EFRD analyses as
17 specified in paragraphs 5.A-5.B of Appendix B;
- 18 d. For failure to timely submit to OSFM the risk analysis as
19 specified in paragraph 6.A of Appendix B;
- 20 e. For failure to timely submit to PHMSA the modified Section
21 9.5 of Plains' IMP, as specified in paragraph 9.A.3 of Appendix B;
- 22 f. For failure to timely submit to PHMSA the modified P&M
23 Recommendation forms, as specified in paragraph 9.B of Appendix
24 B;
- 25 g. For failure to timely conduct EFRD analyses for all Regulated
26 Pipelines for which Plains has not previously conducted an EFRD
27 analysis, as specified in paragraph 10.A of Appendix B;
- 28

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- 1 h. For failure to timely have in place revised valve maintenance
2 procedures, as specified in paragraph 10.B of Appendix B;
- 3 i. For failure to timely create a list of rupture detection methods
4 utilized, as specified in paragraph 11.A of Appendix B;
- 5 j. For failure to timely conduct annual training for controllers on
6 attributes and benefits of various methods of leak detection,
7 including Analog High/Low Threshold, Alarm Deadband, Creep
8 Deviation, and Analog Rate of Change, as specified in paragraph
9 11.B of Appendix B;
- 10 k. For failure to timely submit to PHMSA the computational
11 pipeline monitoring (“CPM”) systems analysis, as specified in
12 paragraph 11.C of Appendix B;
- 13 l. For failure to timely submit to PHMSA the selection of leak
14 detection method procedure, as specified in paragraph 11.D of
15 Appendix B;
- 16 m. For failure to hold or document periodic (at least annual)
17 meetings regarding potential improvements to leak detection, as
18 provided in paragraph 11.E of Appendix B;
- 19 n. For failure to timely have in place a procedure for tracking
20 when instrumentation has been impeded, as provided in paragraph
21 11.F of Appendix B;
- 22 o. For failure to complete, prior to resuming operations on Lines
23 901 or 903, the items identified in paragraph 12.A.1-4 of Appendix
24 B;
- 25 p. For failure to timely submit to OSFM confirmation that all
26 alarm descriptors are accurate, as specified in paragraph 12.B of
27 Appendix B;
- 28 q. For failure to timely conduct the surveys and update the

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1 emergency response plans, as specified in paragraph 13.B.1 of
 2 Appendix B;

3 r. For failure to timely provide emergency response training to
 4 employees, as specified in paragraph 13.B.2 of Appendix B;

5 s. For failure to timely provide control room supervisor training,
 6 as specified in paragraph 13.B.4 of Appendix B;

7 t. For failure to timely submit to PHMSA and/or OSFM, and/or
 8 OSPR, as applicable, notice of drills, as specified in paragraph
 9 13.B.5 of Appendix B, provided that the penalty under this
 10 subsection shall not exceed one Day per drill;

11 u. For failure to timely submit to PHMSA the third-party Safety
 12 Management System report, as specified in paragraph 14.A.1 of
 13 Appendix B;

14 v. For failure to timely review and revise the drug and alcohol
 15 misuse plans, as specified in paragraph 15 of Appendix B;

16 w. For failure to timely submit to PHMSA notice of any material
 17 modification to the IMP, as required by Paragraph 22; and

18 x. For failure to timely submit to PHMSA notice of any material
 19 modification to the Control Room Management Plan or Control
 20 Center General Procedures, as required by Paragraph 23;

21 y. The penalties stipulated in this Section shall accrue as
 22 follows:

Penalty Per Violation	Per Day Period of Noncompliance
\$2,000 penalty per Day	1st to 30th Day
\$4,000 penalty per Day	31st to 60th Day
\$5,500 penalty per Day	61st Day and beyond

1 29. Stipulated Penalties for Non-Compliance with Corrective Action
2 Order Terms. Unless excused under Section XII (Force Majeure), the stipulated
3 penalties described in this Paragraph shall accrue per violation per Day for
4 Defendants' failure to perform the following injunctive relief required under
5 Section X (Corrective Action Order) when due:

- 6 a. For operation of Line 901 in violation of paragraph 1.a of
7 Appendix D;
- 8 b. For failure to timely submit to OSFM a Line 901 Restart Plan,
9 as specified by paragraph 1.b of Appendix D;
- 10 c. For failure to comply with the operating pressure restriction,
11 including requirements for removal of the pressure restriction, for
12 Line 901 specified by paragraphs 1.c and 1.d of Appendix D;
- 13 d. For operation of Line 903, in violation of paragraph 1.e of
14 Appendix D;
- 15 e. For failure to timely submit to OSFM a Line 903 Restart Plan,
16 as specified by paragraph 1.f of Appendix D;
- 17 f. For failure to comply with the operating pressure restriction,
18 including requirements for removal of the pressure restriction, for
19 Line 903 specified by paragraphs 1.g and 1.h of Appendix D;
- 20 g. For failure to timely submit to OSFM any notification
21 specified by paragraph 1.i of Appendix D; and
- 22 h. For failure to submit to OSFM a final Appendix D
23 Documentation Report, as specified by paragraph 1.j of Appendix D.
- 24 i. The penalties stipulated in this Section shall accrue as
25 follows:
- 26
27
28

Penalty Per Violation	Per Day Period of Noncompliance
\$2,000 penalty per Day	1st to 30th Day
\$4,000 penalty per Day	31st to 60th Day
\$5,500 penalty per Day	61st Day and beyond

30. Defendants shall pay stipulated penalties due pursuant to this Section within thirty (30) Days of a written demand.

31. For stipulated penalties accrued pursuant to Subparagraphs 27.a, 28.e, 28.f, 28.g, 28.h, 28.i, 28.j, 28.k, 28.l, 28.m, 28.n, 28.s, 28.t, 28.u, 28.v, 28.w, or 28.x of this Consent Decree, the United States shall have the right to issue a written demand for stipulated penalties, and Defendants must pay to the United States the full amount of any stipulated penalties due and will not be liable to the State Agencies for any such stipulated penalties.

32. For stipulated penalties accrued pursuant to Subparagraph 27.b of this Consent Decree, only CDFW and RWQCB shall have the right to issue a written demand for stipulated penalties and Defendants must pay to the CDFW and RWQCB the full amount of any stipulated penalties due and will not be liable to United States for any such stipulated penalties.

33. For stipulated penalties accrued pursuant to Subparagraphs 28.a, 28.b, 28.c, 28.d, 28.o, 28.p, or Paragraph 29 of this Consent Decree, only OSFM shall have the right to issue a written demand for stipulated penalties, and Defendants must pay to OSFM the full amount of any stipulated penalties due and will not be liable to United States for any such stipulated penalties.

34. For stipulated penalties accrued pursuant to Paragraphs 28.q, 28.r, 28.t, or Paragraph 30 of this Consent Decree, the United States, CDFW, OSFM, or all, may demand stipulated penalties by sending a joint or individual written demand to Defendants, with a copy simultaneously sent to the other Plaintiff(s).

1 a. Where only one or two of the Plaintiffs referenced in
2 Paragraph 35 demand stipulated penalties under Paragraph 35, a
3 copy of the demand will simultaneously be sent to the remaining
4 Plaintiff(s) and they will have forty-five (45) Days to join in the
5 demand.

6 b. Where multiple Plaintiffs referenced in Paragraph 35 demand
7 stipulated penalties for the same violation, Defendants shall pay fifty
8 (50) percent to each of the demanding Plaintiffs (when two Plaintiffs
9 join in the demand); one third to each demanding Plaintiff (when all
10 three Plaintiffs join in the demand); or as allocated by the United
11 States, CDFW, and OSFM.

12 c. Where only one Plaintiff referenced in Paragraph 35 demands
13 stipulated penalties, and the other Plaintiffs do not join in the
14 demand within forty-five (45) Days of receiving the demand,
15 Defendants shall pay one hundred (100) percent to the Plaintiff
16 making the demand.

17 d. If a Plaintiff joins in the demand within forty-five (45) Days
18 but subsequently elects to waive or reduce stipulated penalties, in
19 accordance with Paragraphs 38 or 39 for that violation, Defendants
20 shall not be liable for such portion of the stipulated penalties waived
21 or reduced by such Plaintiff and shall be liable for any stipulated
22 penalties due to the other Plaintiffs joining such demand pursuant to
23 the allocation set forth in Subparagraph 34(b).

24 35. For stipulated penalties arising from a failure to perform obligations
25 pursuant to Subparagraph 27.c, the United States and the State Trustees may
26 demand stipulated penalties by sending a joint written demand to Defendants.

27 36. For all payments made pursuant to this Section, Defendants must
28 follow the payment instructions set forth in Section V (Civil Penalties). Any

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1 transmittal correspondence shall state that payment is for stipulated penalties and
2 shall identify the date of the written demand to which the payment corresponds.

3 37. Stipulated penalties under this Section shall begin to accrue on the
4 Day after the performance is due or on the day a violation occurs, whichever is
5 applicable, and shall continue to accrue until performance is satisfactorily
6 completed, or until the violation ceases. Stipulated penalties shall accrue
7 simultaneously for separate violations of this Consent Decree.

8 38. The United States may, in the unreviewable exercise of its
9 discretion, reduce or waive stipulated penalties otherwise due to the United States
10 under this Consent Decree.

11 39. The applicable State Agencies may, in the unreviewable exercise of
12 their discretion, reduce or waive stipulated penalties otherwise due to the
13 applicable State Agencies under this Consent Decree.

14 40. Stipulated penalties shall continue to accrue as provided in
15 Paragraphs 27 through 29, during any Dispute Resolution, but need not be paid
16 until the following:

17 a. If the dispute is resolved by agreement or by a decision of the
18 United States or the State Agencies, as applicable, that is not
19 appealed to the Court, Defendants shall pay accrued penalties
20 determined to be owing to the United States or the State Agencies,
21 as applicable, together with interest, within thirty (30) Days of the
22 effective date of the agreement or the receipt of the United States' or
23 the State Agencies' decision.

24 b. If the dispute is appealed to the Court and the Plaintiffs
25 prevail in whole or in part, Defendants shall pay all accrued
26 penalties determined by the Court to be owing, together with
27 interest, within sixty (60) Days of receiving the Court's decision or
28 order, except as provided in Subparagraph c, below.

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1 c. If any Party appeals the Court’s decision and a Plaintiff
2 prevails in whole or in part, Defendants shall pay all accrued
3 penalties determined to be owing, together with interest, within
4 fifteen (15) Days of receiving the final appellate court decision.

5 41. If Defendants fail to pay stipulated penalties according to the terms
6 of this Consent Decree, Defendants shall be liable for interest on such penalties,
7 as provided for in 28 U.S.C. § 1961, accruing as of the date payment became due.
8 Nothing in this Paragraph shall be construed to limit the United States or the
9 State Agencies from seeking any remedy otherwise provided by law for
10 Defendants’ failure to pay any stipulated penalties.

11 42. The payment of stipulated penalties, if any, shall not alter in any
12 way Defendants’ obligation to complete the performance of the requirements of
13 this Consent Decree.

14 43. Subject to the provisions of Section XVII (Effect of
15 Settlement/Reservation of Rights) of this Consent Decree, the stipulated penalties
16 provided for in this Consent Decree shall be in addition to any other rights,
17 remedies, or sanctions available to the United States or the State Agencies
18 (including, but not limited to, statutory penalties, additional injunctive relief,
19 mitigation or offsets measures, and/or contempt) for Defendants’ violation of this
20 Consent Decree or applicable laws.

21 **XII. FORCE MAJEURE**

22 44. “Force Majeure,” for purposes of this Consent Decree, is defined as
23 any event arising from causes beyond the control of Defendants, of any entity
24 controlled by Defendants, or of Defendants’ contractors that delays or prevents
25 the performance of any obligation under this Consent Decree despite Defendants’
26 best efforts to fulfill the obligation. The requirement that Defendants exercise
27 “best efforts to fulfill the obligation” includes using best efforts to anticipate any
28 potential Force Majeure event and best efforts to address the effects of any

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1 potential Force Majeure event (a) as it is occurring and (b) following the potential
2 Force Majeure, such that the delay and any adverse effects of the delay are
3 minimized. “Force Majeure” does not include Defendants’ financial inability to
4 perform any obligation under this Consent Decree.

5 45. If any event occurs or has occurred that may delay the performance
6 of any obligation under this Consent Decree, whether or not caused by a Force
7 Majeure event, Defendants shall provide notice orally or by electronic
8 transmission to the relevant Plaintiff(s), within five (5) Days of when Defendants
9 first knew that the event might cause a delay. Within ten (10) Days thereafter,
10 Defendants shall provide in writing to such Plaintiffs an explanation and
11 description of the reasons for the delay; the anticipated duration of the delay; the
12 actions taken or to be taken to prevent or minimize the delay; a schedule for
13 implementation of any measures to be taken to prevent or mitigate the delay or
14 the effect of the delay; Defendants’ rationale for attributing such delay to a Force
15 Majeure event if it intends to assert such a claim; and a statement as to whether,
16 in the opinion of Defendants, such event may cause or contribute to an
17 endangerment to public health, welfare or the environment. Defendants shall
18 provide with any notice the documentation that Defendants are relying on to
19 support the claim that the delay was attributable to a Force Majeure event.

20 Failure to comply with the above requirements shall preclude Defendants from
21 asserting any claim of Force Majeure for that event for the period of time of such
22 failure to comply, and for any additional delay caused by such failure.

23 Defendants shall be deemed to know of any circumstance of which Defendants,
24 any entity controlled by Defendants, or Defendants’ contractors knew or should
25 have known.

26 46. If Plaintiffs agree that the delay or anticipated delay is attributable to
27 a Force Majeure event, the time for performance of the obligations under this
28 Consent Decree that are affected by the Force Majeure event will be extended by

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1 Plaintiffs for such time as is necessary to complete those obligations. An
2 extension of the time for performance of the obligations affected by the Force
3 Majeure event shall not, of itself, extend the time for performance of any other
4 obligation. Plaintiffs will notify Defendants in writing of the length of the
5 extension, if any, for performance of the obligations affected by the Force
6 Majeure event.

7 47. If Plaintiffs do not agree that the delay or anticipated delay has been
8 or will be caused by a Force Majeure event, Plaintiffs will notify Defendants in
9 writing of their decision.

10 48. If Defendants elect to invoke the Dispute Resolution procedures set
11 forth in Section XIII (Dispute Resolution), in response to Plaintiffs'
12 determination in Paragraph 47 above, it shall do so no later than thirty (30) Days
13 after receipt of Plaintiffs' notice. In any such proceeding, Defendants shall have
14 the burden of demonstrating by a preponderance of the evidence that the delay or
15 anticipated delay has been or will be caused by a Force Majeure event, that the
16 duration of the delay or the extension sought was or will be warranted under the
17 circumstances, that best efforts were exercised to avoid and mitigate the effects
18 of the delay, and that Defendants complied with the requirements of Paragraphs
19 44 and 45. If Defendants carry this burden, the delay at issue shall be deemed not
20 to be a violation by Defendants of the affected obligation of this Consent Decree
21 identified to Plaintiffs and the Court.

22 **XIII. DISPUTE RESOLUTION**

23 49. Unless otherwise expressly provided for in this Consent Decree, the
24 Dispute Resolution procedures of this Section shall be the exclusive mechanism
25 to resolve disputes arising under or with respect to this Consent Decree.
26 Defendants' failure to seek resolution of a dispute under this Section shall
27 preclude Defendants from raising any such issue as a defense to an action by
28 Plaintiffs to enforce any obligation of Defendants arising under this Consent

1 Decree.

2 50. Informal Dispute Resolution. Any dispute subject to Dispute
3 Resolution under this Consent Decree shall first be the subject of informal
4 negotiations. The dispute shall be considered to have arisen when Defendants
5 send the relevant Plaintiff(s) a written Notice of Dispute. Such Notice of Dispute
6 shall state clearly the matter in dispute. The period of informal negotiations shall
7 not exceed thirty (30) Days from the date the dispute arises, unless that period is
8 modified by written agreement. If the parties cannot resolve a dispute by
9 informal negotiations, then the position advanced by Plaintiffs shall be
10 considered binding unless, within forty-five (45) Days after the conclusion of the
11 informal negotiation period, Defendants invoke formal Dispute Resolution
12 procedures as set forth below.

13 51. Formal Dispute Resolution. Defendants shall invoke formal Dispute
14 Resolution procedures, within the time period provided in the preceding
15 Paragraph, by serving on Plaintiffs a written Statement of Position regarding the
16 matter in dispute. The Statement of Position shall include, but need not be
17 limited to, any factual data, analysis, or opinion supporting Defendants' position
18 and any supporting documentation relied upon by Defendants.

19 52. Plaintiffs shall serve their Statement of Position within forty-five
20 (45) Days of receipt of Defendants' Statement of Position. Plaintiffs' Statement
21 of Position shall include, but need not be limited to, any factual data, analysis, or
22 opinion supporting that position and any supporting documentation relied upon
23 by Plaintiffs. Plaintiffs' Statement of Position shall be binding on Defendants,
24 unless Defendants file a motion for judicial review of the dispute in accordance
25 with the following Paragraph.

26 53. Defendants may seek judicial review of the dispute by filing with the
27 Court and serving on the relevant Plaintiff(s), in accordance with Section XX
28 (Notices), a motion requesting judicial resolution of the dispute. The motion

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1 must be filed within thirty (30) Days of receipt of Plaintiffs' Statement of
2 Position pursuant to the preceding Paragraph. The motion shall contain a written
3 statement of Defendants' position on the matter in dispute, including any
4 supporting factual data, analysis, opinion, or documentation, and shall set forth
5 the relief requested and any schedule within which the dispute must be resolved
6 for orderly implementation of this Consent Decree.

7 54. Plaintiffs shall respond to Defendants' motion within the time period
8 allowed by the Local Rules of this Court or by a schedule set by the Court.
9 Defendants may file a reply memorandum to the extent permitted by the Local
10 Rules.

11 55. Except as otherwise provided in this Consent Decree, in any dispute
12 brought under Paragraph 51, Defendants shall bear the burden of demonstrating
13 that its position complies with this Consent Decree, based on the Statements of
14 Position, and under applicable standards of review.

15 56. The invocation of Dispute Resolution procedures under this Section
16 shall not, by itself, extend, postpone, or affect in any way any obligation of
17 Defendants under this Consent Decree, unless and until final resolution of the
18 dispute so provides. Stipulated penalties with respect to the disputed matter shall
19 continue to accrue until the final resolution of the dispute. Payment shall be
20 stayed pending resolution of the dispute. If Defendants do not prevail on the
21 disputed issue, stipulated penalties shall be assessed and paid as provided in
22 Section XI (Stipulated Penalties).

23 **XIV. REPORTING**

24 57. After the Effective Date, by March 31 and September 30 of the
25 following years until termination of this Consent Decree per Section XXIV
26 (Termination), Defendants shall submit to the Plaintiffs in accordance with
27 Section XX (Notices) bi-annual reports that shall describe the status of
28 Defendants' compliance with the Consent Decree, including implementation of

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1 the injunctive relief requirements set forth in Appendices B and D. The report
2 will be organized to show the measures taken to comply with each of the
3 requirements set forth in Appendices B and D, whether the measures were taken
4 timely, the status of any permitting action that may affect compliance with the
5 Consent Decree, and whether the measures taken have achieved compliance with
6 the requirement.

7 **XV. CERTIFICATION**

8 58. Each report submitted by Defendants under Section XIV (Reporting)
9 shall be signed by either the Chief Executive Officer, the President, an Executive
10 Vice President, a Senior Vice President, or General Counsel who is an authorized
11 representative of Defendants, and must contain the following statement:

12 I certify under penalty of law that this document and all
13 attachments were prepared under my direction or
14 supervision in accordance with a system designed to
15 assure that qualified personnel properly gather and
16 evaluate the information submitted. Based on any
17 personal knowledge and my inquiry of the person or
18 persons who manage the system, or those persons
19 directly responsible for gathering the information, the
20 information submitted is, to the best of my knowledge
and belief, true, accurate, and complete. I am aware that
there are significant penalties for submitting false
information, including the possibility of fine and
imprisonment for knowing violations.

21 **XVI. INFORMATION COLLECTION AND RETENTION**

22 59. Plaintiffs and their representatives shall have the right of entry into
23 any facility covered by this Consent Decree, at all reasonable times and upon
24 reasonable notice, upon presentation of credentials, to:

- 25 a. monitor the progress of activities required under this Consent
26 Decree;
- 27 b. verify any data or information submitted to the Plaintiffs in
28 accordance with the terms of this Consent Decree;

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- 1 c. obtain documentary evidence, including photographs and
- 2 similar data; and
- 3 d. assess Defendants' compliance with this Consent Decree.

4 60. Until one (1) year after the termination of this Consent Decree,
5 Defendants shall retain, and shall instruct their contractors and agents to preserve
6 or deliver to Plains, all non-identical copies of all documents, records, or other
7 information (including documents, records, or other information in electronic
8 form) in their or their contractors' or agents' possession or control, or that come
9 into their or their contractors' or agents' possession or control, and that relate in
10 any manner to Defendants' performance of their obligations under this Consent
11 Decree. At any time during this information-retention period, upon request by
12 the Plaintiffs, Defendants shall provide copies of any documents, records, or
13 other information required to be maintained under this Paragraph.

14 61. This Consent Decree in no way limits or affects any right of entry
15 and inspection, or any right to obtain information, held by the United States or
16 the State Agencies pursuant to applicable federal or state laws, regulations, or
17 permits, nor does it limit or affect any duty or obligation of Defendants to
18 maintain documents, records, or other information imposed by applicable federal
19 or state laws, regulations, or permits.

20 62. For any documents, records, or other information required to be
21 submitted to Plaintiffs pursuant to this Consent Decree, Plains may assert a claim
22 of business confidentiality or other protections applicable to the release of
23 information by Plaintiffs, covering part or all of the information required to be
24 submitted to Plaintiffs pursuant to this Consent Decree in accordance with, as
25 applicable, 49 C.F.R. Part 7, 49 C.F.R. Part 190, and 40 C.F.R Part 2. Plains
26 must mark the claim of confidentiality in writing on each page, and include a
27 statement specifying the grounds for each claim of confidentiality.

28 63. The federal agency Plaintiffs are subject to applicable laws

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1 governing the disclosure of information under the Freedom of Information Act
2 (“FOIA”) (5 U.S.C. § 552 *et seq.*). If a federal agency Plaintiff receives a request
3 pursuant to FOIA for records produced pursuant to the Consent Decree, that
4 Plaintiff will, to the extent permitted by law, treat those records as exempt from
5 disclosure, and give Defendants a reasonable opportunity to identify portions of
6 documents Defendants have claimed as confidential and that may be subject to
7 the request, and to specify the grounds for each claim of confidentiality. In
8 accordance with applicable regulations, if the federal agency Plaintiff determines
9 that the records are not exempt from disclosure, the Plaintiff shall provide notice
10 of the determination to Defendants prior to making any record available to the
11 public.

12 64. For documents provided to PHMSA under this Consent Decree,
13 Defendants need not provide redacted copies when the documents are produced.
14 Within fourteen (14) Days of notification from PHMSA of a FOIA request, or
15 such other time as agreed upon, Defendants will provide a copy of the relevant
16 records with confidential information redacted along with explanations of the
17 asserted grounds for confidentiality.

18 65. State Agency Plaintiffs are subject to the California Public Records
19 Act (“CPRA”) (California Government Code §§ 6250 *et seq.*). If a State Agency
20 Plaintiff receives a request pursuant to the CPRA for records produced pursuant
21 to the Consent Decree, that Plaintiff will, to the maximum extent permitted by
22 law, treat those records as exempt from disclosure, and give Defendants a
23 reasonable opportunity to submit redacted copies of the requested records. If the
24 Plaintiff determines that the records are not exempt from disclosure, the Plaintiff
25 shall provide notice of the determination to Defendants prior to making any
26 record available to the public.

27 66. The requirements of this Paragraph apply to Defendants’ production
28 of documents to PHMSA only. Defendants shall produce all documents required

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1 to be produced in connection with this Consent Decree in, at Defendants’ option,
2 either native format via electronic media or secure file transfer protocol (“FTP”).
3 Any encryption or access restriction shall be on a container level only, *i.e.*, only
4 the electronic media or the top-level folder containing the documents shall be
5 encrypted and Plaintiffs shall have unrestricted access to the files/folders within
6 the electronic media or the top-level folder without need for additional decryption
7 or access codes. Regardless of production method or encryption, individual
8 documents shall be produced in a manner that allows the Plaintiffs to view, print,
9 copy, save, download, and share each document within Plaintiffs’ own
10 environment without restriction, tracking or monitoring by Defendants, or
11 automatically generated changes to the document (*e.g.*, without entering access
12 codes prior to each download, and without automatically generated watermarks
13 stating the download date and time).

14 67. At the conclusion of the information-retention period, Defendants
15 shall provide ninety (90) Days’ notice to Plaintiffs of Defendants’ resumption of
16 internal document destruction policies for documents, records, or other information
17 subject to the requirements of Paragraph 60.

18 68. [*Intentionally left blank.*]

19 **XVII. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS**

20 69. This Consent Decree resolves the civil claims of the United States
21 and the State Agencies for the matters alleged in the Complaint filed in this
22 action for the Refugio Incident.

23 70. Subject to the reservations of rights specified in Paragraph 71, this
24 Consent Decree also resolves all civil and administrative penalty claims that
25 could be brought by PHMSA, for violations of the Pipeline Safety Laws specified
26 below that occurred on any of Defendants’ Regulated Pipelines prior to January
27 28, 2019, the date that PHMSA’s ongoing “Integrated Inspection” of a portion of
28 Defendants’ Regulated Pipelines and other pipeline facilities began. The specific

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1 Pipeline Safety Laws subject to this Paragraph are the following (including other
2 regulations expressly incorporated therein):

- 3 a. 49 C.F.R. Part 194 Subpart B – Response Plans;
- 4 b. 49 C.F.R. Part 195 Subpart B – Reporting;
- 5 c. 49 C.F.R. Part 195 Subpart E – Pressure Testing;
- 6 d. 49 C.F.R. Part 195 Subpart F – Operation and Maintenance,
7 sections 195.402, 195.403, 195.404, 195.406, 195.408, 195.412,
8 195.420, 195.422, 195.428, 195.436, 195.442, 195.444, 195.446,
9 195.452;
- 10 e. 49 C.F.R. Part 195 Subpart G – Qualification of Pipeline
11 Personnel, as it relates to valve maintenance;
- 12 f. 49 C.F.R. Part 195 Subpart H – Corrosion Control;
- 13 g. 49 C.F.R. Part 199 – Drug and Alcohol Testing; and
- 14 h. All recordkeeping, documentation, and document production
15 requirements in the provisions listed in subsections 70.a-70.g, and
16 49 C.F.R. section 190.203 and Part 195.

17 71. The United States, on behalf of PHMSA, reserves all legal and
18 equitable remedies to address violations of the Pipeline Safety Laws described in
19 Paragraph 70 that occur on or after January 28, 2019, including violations that
20 may have begun prior to such date and continued subsequent to January 28, 2019.
21 A separate violation of the Pipeline Safety Laws occurs for each day that the
22 violation continues, pursuant to 49 U.S.C. § 60122(a).

23 72. This Consent Decree also resolves all civil and administrative
24 penalty claims that could be brought by OSFM against Defendants for violations
25 of the Pipeline Safety Laws and the Elder California Pipeline Safety Act
26 as specified below relating to Line 901, Line 903, or Line 2000 that occurred
27 prior to January 28, 2019. OSFM reserves all legal and equitable remedies to
28 address violations of the specified Pipeline Safety Laws that occur on or after

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1 January 28, 2019, including violations that may have begun prior to such date
2 and continued subsequent to January 28, 2019. The specific Pipeline Safety
3 Laws and Elder California Pipeline Safety Act subject to this Paragraph are:

- 4 a. The Pipeline Safety Laws specified in Paragraph 70; and
- 5 b. California Government Code §§ 51012.3, 51013, 51013.5,
6 51014, 51015, 51015.4, 51015.5 (for Line 901 and Line 903 only),
7 and 51018.

8 73. For any reportable pipeline accident, as defined in 49 C.F.R.
9 § 195.50, occurring on or after January 28, 2019, on any of Defendants'
10 Regulated Pipelines, Paragraphs 70 and 72 shall not limit the right of PHMSA
11 and OSFM to sue or pursue administrative or other remedies for violations
12 (including penalties) under the Pipeline Safety Laws and the Elder California
13 Pipeline Safety Act for such accident. Nothing in Paragraphs 70 through 72 shall
14 be construed to limit the legal and equitable remedies of the United States or
15 State Agencies, other than PHMSA and OSFM.

16 74. The United States and the State Agencies reserve all legal and
17 equitable remedies available to enforce the provisions of this Consent Decree.
18 This Consent Decree shall not be construed to limit the rights of the United States
19 or the State Agencies to obtain penalties, injunctive relief, or other administrative
20 or judicial remedies under the CWA, OPA, Pipeline Safety Laws, or under other
21 federal or state laws, regulations, or permit conditions, except as specified in
22 Paragraphs 69, 70, and 72.

23 75. The United States reserves all legal and equitable remedies to address
24 any imminent and substantial endangerment or threat to the public health or
25 welfare or the environment arising at, or posed by, Defendants' operations,
26 whether related to the violations addressed in this Consent Decree or otherwise.
27 PHMSA further reserves the right to issue to Defendants corrective action orders
28 pursuant to 49 C.F.R § 190.233; emergency orders pursuant to 49 C.F.R.

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1 § 190.236; and safety orders pursuant to 49 C.F.R. § 190.239. The State Agencies
2 reserve all legal and equitable remedies under California Government Code
3 §§ 8670.57, 8670.69.4, 51013.5, 51015.5, 51018.6, 51018.7 and 51018.8,
4 California Water Code §§ 13301, 13304, 13340, and 13386, and California Health
5 & Safety Code § 13107.5 to address (1) conditions threatening to cause or creating
6 a substantial risk of an unauthorized discharge of oil into waters of the State of
7 California, (2) a discharge of waste threatening to cause a condition of pollution or
8 nuisance, or (3) a discharge which poses a substantial probability of harm to
9 persons, property or natural resources.

10 76. This Consent Decree also shall not be construed to in any way limit or
11 waive the claims set forth in the case entitled *California State Lands Commission,*
12 *et al. v. Plains Pipeline, L.P., et al.*, Case No. 18CV02504 (Cal. Sup. Court) and
13 Case No. B295632 (Cal. Ct. App.).

14 77. In any subsequent administrative or judicial proceeding initiated by
15 the United States or the State Agencies for injunctive relief, civil penalties, other
16 appropriate relief relating to Defendants' violations alleged in Plaintiffs'
17 Complaint, Defendants shall not assert, and may not maintain, any defense or
18 claim based upon the principles of waiver, *res judicata*, collateral estoppel, issue
19 preclusion, claim preclusion, claim-splitting, or other defenses based upon any
20 contention that the claims raised by the United States or the State Agencies in the
21 subsequent proceeding should have been brought in the instant case, except with
22 respect to claims that have been specifically resolved pursuant to Paragraphs 69,
23 70, and 72.

24 78. This Consent Decree is not a permit, or a modification of any
25 permit, under any federal, state, or local laws, or regulations. Defendants are
26 responsible for achieving and maintaining full compliance with all applicable
27 federal, state, and local laws, regulations, and permits; and Defendants'
28 compliance with this Consent Decree shall be no defense to any action

United States of America and the People of the State of California v.
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1 commenced pursuant to any such laws, regulations, or permits, except as set forth
2 herein. The United States and the State Agencies do not, by their consent to the
3 entry of this Consent Decree, warrant or aver in any manner that Defendants'
4 compliance with any aspect of this Consent Decree will result in compliance with
5 provisions of the CWA, OPA, Pipeline Safety Laws, or with any other provisions
6 of federal, state, or local laws, regulations, or permits.

7 79. This Consent Decree does not limit or affect the rights of Defendants
8 or of the United States or the State Agencies against any third-parties, not party
9 to this Consent Decree, nor does it limit the rights of third-parties, not party to
10 this Consent Decree, against Defendants, except as otherwise provided by law.

11 80. This Consent Decree shall not be construed to create rights in, or
12 grant any cause of action to, any third-party not party to this Consent Decree.

13 81. Plaintiffs will not submit any claim for restitution for Natural
14 Resource Damages in *The People of the State of California v. Plains All*
15 *American Pipeline, L.P.*, Case No. 1495091 (Cal. Sup. Court).

16 82. By entering into this settlement, Defendants do not admit the
17 Pipeline Safety Laws violations alleged in the Complaint or described in this
18 Consent Decree by the United States on behalf of PHMSA; therefore, any
19 allegations of violations of these Pipeline Safety Laws do not constitute a finding
20 of violation and may not be used in any civil proceeding of any kind as evidence
21 or proof of any fact, fault or liability, or as evidence of the violation of any law,
22 rule, regulation, order, or requirement, except in a proceeding to enforce the
23 provisions of this Consent Decree. However, the allegations of violations set
24 forth in the Complaint may be: (1) considered by PHMSA to constitute prior
25 offenses in any future PHMSA enforcement action brought by the agency against
26 Plains, and (2) used for statistical purposes to identify violations that PHMSA
27 deems as causal to an incident or to increase the consequences of an incident.
28 Notwithstanding the forgoing, alleged violations subject to Paragraph 70 shall not

United States of America and the People of the State of California v.
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1 be considered by PHMSA to constitute prior offenses in any future PHMSA
2 enforcement action brought by the agency against Plains.

3 83. By entering into this settlement, Defendants do not admit the
4 allegations of California Water Code §§ 13350 and 13385 violations set forth in
5 the Complaint; therefore, any allegations of violations of these statutes do not
6 constitute a finding of violation and may not be used in any civil proceeding of
7 any kind as evidence or proof of any fact, fault or liability, or as evidence of the
8 violation of any law, rule, regulation, order, or requirement, except in a
9 proceeding to enforce the provisions of this Consent Decree. However, the
10 allegations of California Water Code §§ 13350 and 13385 violations set forth in
11 the Complaint may be considered by the State Water Resources Control Board or
12 Regional Water Quality Control Boards to constitute prior offenses in any future
13 enforcement action brought by any of these agencies against Plains.

14 84. Subject to the terms of this Consent Decree, no provision contained
15 herein affects or relieves Plains of their responsibilities to comply with all
16 applicable requirements of the CWA, OPA, the Pipeline Safety Laws, federal or
17 state laws, and the regulations and orders issued thereunder. Subject to the terms
18 of this Consent Decree, nothing herein shall limit or reduce the Plaintiffs' right of
19 access, entry, inspection, and information-gathering or their authority to bring
20 enforcement actions against Defendants pursuant to the CWA, OPA, the Pipeline
21 Safety Laws, federal or state laws, the regulations and orders issued thereunder,
22 or any other applicable provision of federal or state law.

23 85. Defendants hereby covenant not to sue Plaintiffs for any claims
24 related to the Refugio Incident, or response activities in connection with the
25 Incident, pursuant to the CWA, OPA, the Pipeline Safety Laws, federal or state
26 laws, or any other law or regulation for acts or omissions through the date on
27 which this Consent Decree is lodged with the Court.

28 86. Defendants covenant not to sue and agree not to assert any direct or

*United States of America and the People of the State of California v.
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1 indirect claim for reimbursement related to the Refugio Incident from the OSLTF
2 or pursuant to any other provision of law.

3 87. The United States reserves the right to seek reimbursement from
4 Defendants for claims relating to the Refugio Incident paid after the date on
5 which the Consent Decree is lodged with the Court from the OSLTF pursuant to
6 33 U.S.C. § 2712.

7 **XVIII. TRANSFER AND ACQUISITION OF ASSETS**

8 88. In the event Defendants sell or transfer ownership of or operating
9 responsibility for Lines 901, 903, or 2000, or any lines built to replace Lines 901
10 or 903, Defendants will obtain from the transferee an agreement to be bound by
11 those provisions of this Consent Decree and Appendices B and D that are
12 specifically applicable to the asset(s) acquired, unless Defendants have already
13 completed the required action or unless OSFM agrees to relieve the transferee of
14 the obligations of any otherwise applicable provision. Those provisions of
15 Appendix B are:

- 16 a. For existing but non-operational segments of Lines 901 and
17 903, paragraphs 1.A, 1.B, 1.E, 2.B, 2.C., 4, 5, 6, 7.A, 12.A of
18 Appendix B;
- 19 b. For the operational segment of Line 903 from Pentland to
20 Emidio, paragraphs 1.C, 1.E, 4, 5, 6, 7.A of Appendix B;
- 21 c. For any lines built to replace Lines 901 or 903, paragraphs
22 2.A.1, 5, 7.B, 12.A of Appendix B; and
- 23 d. For Line 2000, paragraphs 1.D, 1.E, 4, 5, 6, 7.A, 12.B. of
24 Appendix B.

25 89. In the event Defendants sell or transfer ownership of or operating
26 responsibility for Lines 901, 903, or 2000, or any lines built to replace Lines 901
27 or 903, Defendants shall provide a copy of this Consent Decree to the prospective
28 transferee at least fourteen (14) Days prior to such transfer. Defendants shall

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1 provide written notice of any such transfer to OSFM within ten (10) Days after
2 the date Defendants publicly disclose the transaction or the date the transaction is
3 closed, whichever is earlier. Prior to the transfer, Defendants may notify OSFM
4 that Defendants have completed certain required actions of this Consent Decree,
5 or request that OSFM relieve the transferee of certain obligations of otherwise
6 applicable provisions, such that the transferee will not be bound by those
7 requirements. Defendants shall provide to Plaintiffs documentation
8 demonstrating the transferee's agreement to be bound by the relevant provisions
9 of the Consent Decree. Defendants shall provide to the transferee copies of those
10 portions of relevant emergency response plans that relate to the transferred asset.

11 90. In the event of the sale or transfer pursuant to an arm's-length
12 transaction of Defendants' Regulated Pipelines other than Lines 901, 903, or
13 2000, or any lines built to replace Lines 901 or 903, to an independent third-party
14 transferee, the transferee shall not be subject to the requirements of this Consent
15 Decree. Defendants shall provide a copy of this Consent Decree to the transferee
16 at least fourteen (14) Days prior to such transfer. Defendants shall provide
17 written notice of any such transfer, including documentation demonstrating that
18 the Consent Decree was provided to the transferee, to PHMSA within ten (10)
19 Days after the date Defendants publicly disclose the transaction or the date the
20 transaction is closed, whichever is earlier. Defendants' obligations under this
21 Consent Decree with respect to all non-transferred assets shall not be affected.

22 91. For all Regulated Pipeline assets that Defendants assume operating
23 responsibility for after the Effective Date, Plains is obligated to apply Article II
24 (Company Wide Provisions) of Appendix B of this Consent Decree to the newly
25 acquired assets.

26 **XIX. COSTS**

27 92. Except as otherwise stated in this Consent Decree, the Parties shall
28 bear their own costs related to this action and this Consent Decree, including

*United States of America and the People of the State of California v.
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1 attorneys' fees; provided, however, the United States and the State Agencies shall
2 be entitled to collect the costs (including attorneys' fees) incurred in any action
3 necessary to collect any portion of the civil penalty or any stipulated penalties
4 due but not paid by Defendants.

5 **XX. NOTICES**

6 93. Unless otherwise specified in this Consent Decree, whenever
7 notifications, submissions, reports, or communications are required by this
8 Consent Decree, they shall be made in writing, sent electronically by email
9 provided by the Parties, and addressed to all Parties as follows:

10 As to the United States by email: eescdcopy.enrd@usdoj.gov
11 Re: DJ # 90-5-1-1-11340

12 As to the United States by mail: EES Case Management Unit
13 Environment and Natural Resources
14 Division
15 U.S. Department of Justice
16 P.O. Box 7611
17 Washington, D.C. 20044-7611
18 Re: DJ # 90-5-1-1-1130

19 As to PHMSA: James M. Pates
20 Assistant Chief Counsel
21 for Pipeline Safety
22 U.S. Department of Transportation
23 Pipeline and Hazardous Materials
24 Safety Administration
25 1200 New Jersey Ave. SE. E-26
26 Washington, DC. 20590

27 As to EPA: Andrew Helmlinger
28 Attorney Advisor
U.S. EPA Region IX
75 Hawthorne Street (ORC-3)
San Francisco, California 94104

*United States of America and the People of the State of California v.
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As to DOI: Clare Cragan
U.S. Department of the Interior
Office of the Solicitor
755 Parfet St., Suite 151
Lakewood, Colorado 80215

As to NOAA: National Oceanic and Atmospheric
Administration
Office of General Counsel
Natural Resources Section
ATTN: Christopher J. Plaisted
501 W. Ocean Blvd, Suite 4470
Long Beach, California 90802

As to USCG: Patricia V. Kingcade
Attorney Advisor
National Pollution Funds Center,
US Coast Guard
2703 Martin Luther King Jr. Ave SE
Washington, DC 20593-7605

As to the State Agencies: Michael Zarro
Deputy Attorney General
Office of the Attorney General
Natural Resources Law Section
300 S. Spring St., Suite 11220
Los Angeles, California 90013

As to CDFW: California Department of Fish
and Wildlife
Office of Spill Prevention and Response
Attn: Katherine Verrue-Slater
Senior Counsel
P.O. Box 160362
Sacramento, California 95816-0362

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As to CDPR: California Department of Parks and Recreation
Attn: Laura A. Reimche, Senior Counsel
1416 Ninth Street, Room 1404-6
Sacramento, California 95814

As to CSLC: California State Lands Commission
Attn: Patrick Huber, Legal Division
100 Howe Avenue, Suite 100-South
Sacramento, California 95825

As to OSFM: California Department of Forestry and Fire Protection
Legal Services Office
Attn: Joshua Cleaver, Staff Counsel
P.O. Box 944246
Sacramento, California 94244-2460

As to RWQCB: California Central Coast Regional Water Quality Control Board
Attn: Naomi Rubin, Attorney III
801 K Street
Sacramento, California 95814

As to UC: Barton Lounsbury, Senior Counsel
University of California
Office of the General Counsel
1111 Franklin Street, 8th Floor
Oakland, California 94607

As to Defendants: Megan Prout
Senior Vice President
Commercial Law and Litigation
333 Clay Street, Suite 1600
Houston, Texas 77002

1 Henry Weissmann
2 Daniel B. Levin
3 Colin Devine
4 Munger, Tolles & Olson LLP
5 350 S. Grand Ave, 50th Floor
6 Los Angeles, California 90071

7 Steven H. Goldberg
8 Nicole Granquist
9 Downey Brand LLP
10 621 Capitol Mall, 18th Floor
11 Sacramento, California 95814

12 94. Any Party may, by written notice to the other Parties, change its
13 designated notice recipient or notice address provided above.

14 95. Notices submitted pursuant to this Section shall be deemed
15 submitted upon mailing, or emailing unless otherwise provided in this Consent
16 Decree or by mutual agreement of the Parties in writing.

17 **XXI. EFFECTIVE DATE**

18 96. The Effective Date of this Consent Decree shall be the date upon
19 which this Consent Decree is entered by the Court, or a motion to enter this
20 Consent Decree is granted, whichever occurs first, as recorded on the Court's
21 docket.

22 **XXII. RETENTION OF JURISDICTION**

23 97. The Court shall retain jurisdiction over this case until termination of
24 this Consent Decree, for the purpose of effectuating or enforcing compliance with
25 the terms of this Consent Decree.

26 **XXIII. MODIFICATION**

27 98. The terms of this Consent Decree, including any attached
28 Appendices, may be modified only by a subsequent written agreement signed by
the Parties. Where the modification constitutes a material change to any term of
this Consent Decree, it shall be effective only upon approval of the Court.

*United States of America and the People of the State of California v.
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1 any dispute regarding termination until sixty (60) Days after receipt of the
2 Plaintiffs' response to Defendants' Request for Termination.

3 **XXV. PUBLIC PARTICIPATION**

4 103. This Consent Decree shall be lodged with the Court for a period of
5 not fewer than thirty (30) Days for public notice and comment in accordance with
6 28 C.F.R. § 50.7. The Parties agree and acknowledge that the final approval by
7 Plaintiffs and entry of this Consent Decree are subject to notice of lodging of the
8 Consent Decree and a public comment period. Plaintiffs reserve the right to
9 withdraw or withhold consent if the comments disclose facts or considerations
10 that indicate that this Consent Decree is inappropriate, improper, or inadequate.

11 104. Defendants consent to entry of this Consent Decree without further
12 notice and agree not to withdraw from or oppose entry of this Consent Decree by
13 the Court or to challenge any provision of the Consent Decree, unless Plaintiffs
14 have notified Defendants in writing that Plaintiffs no longer support entry of the
15 Consent Decree.

16 **XXVI. SIGNATORIES/SERVICE**

17 105. Each undersigned representative of Defendants, the State of
18 California Attorney General's Office, CDFW, CDPR, CSLC, OSFM, RWQCB,
19 UC, the Assistant Attorney General for the Environment and Natural Resources
20 Division of the Department of Justice, PHMSA, and EPA certifies that he or she
21 is fully authorized to enter into the terms and conditions of this Consent Decree
22 and to execute and legally bind the Party he or she represents to the terms of this
23 Consent Decree.

24 106. This Consent Decree may be signed in counterparts, and such
25 counterpart signature pages shall be given full force and effect. For purposes of
26 this Consent Decree, a signature page that is transmitted electronically (*e.g.*, by
27 emailed PDF) shall have the same effect as an original.

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*United States of America and the People of the State of California v.
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XXVII. INTEGRATION

107. This Consent Decree constitutes the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in the Consent Decree and supersedes all prior agreements and understandings, whether oral or written, concerning the settlement embodied herein. The Parties acknowledge that there are no representations, agreements, or understandings relating to the settlement other than those expressly contained in this Consent Decree.

XXVIII. FINAL JUDGMENT

108. Upon approval and entry of this Consent Decree by the Court, this Consent Decree shall constitute a final judgment of the Court as to the Parties.

XXIX. 26 U.S.C. SECTION 162(f)(2)(A)(ii) IDENTIFICATION

109. For purposes of the identification requirement of Section 162(f)(2)(A)(ii) of the Internal Revenue Code, 26 U.S.C. § 162(f)(2)(A)(ii), performance of Section III (Applicability), Paragraph 5; Section VI (Natural Resource Damages), Paragraph 12; Section IX (Injunctive Relief), Subparagraphs 22.a, 22.b, 22.c, 23.a, 23.b, 23.c, Paragraph 24, and related Appendix B; Section XIV (Reporting), Paragraph 57; Section XV (Certification), Paragraph 58; and Section XVI (Information Collection and Retention), Paragraphs 59, 60, and 66 is restitution or required to come into compliance with law to the extent it applies to federal agencies.

Dated and entered this _____ day of _____, 20__.

UNITED STATES DISTRICT JUDGE


United States of America and the People of the State of California v. Plains All American Pipeline, L.P. and Plains Pipeline, L.P.
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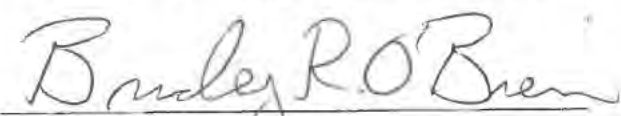
THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of *United States of America and the People of the State of California v. Plains All American Pipeline, L.P. and Plains Pipeline, L.P.*

FOR THE UNITED STATES OF AMERICA:

3/12/2020
Date


BRUCE S. GELBER
Deputy Assistant Attorney General
Environment and Natural Resources
Division U.S. Department of Justice

3/13/2020
Date


BRADLEY R. O'BRIEN
ANGELA MO
Environmental Enforcement Section
Environment and Natural Resources

Division

United States of America and the People of the State of California v. Plains All American Pipeline, L.P. and Plains Pipeline, L.P.
Consent Decree

1 THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of
2 *United States of America and the People of the State of California v. Plains All*
3 *American Pipeline, L.P and Plains Pipeline, L.P.*

4 FOR THE UNITED STATES DEPARTMENT OF TRANSPORTATION,
5 PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION:

6
7 3 March 2020

8 Date



9 PAUL ROBERTI

10 Chief Counsel

11 U.S. Department of Transportation

12 Pipeline and Hazardous Materials Safety
13 Administration

14 1200 New Jersey Avenue, SE

15 Washington, DC 20590

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United States of America and the People of the State of California v.
Plains All American Pipeline, L.P. and Plains Pipeline, L.P.

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1 THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of
2 *United States of America and the People of the State of California v. Plains All*
3 *American Pipeline, L.P. and Plains Pipeline, L.P.*

4 FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY:

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6 3-2-20
7 Date

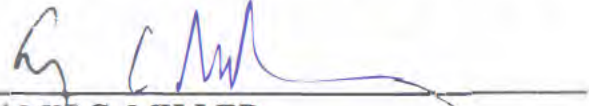

8 SUSAN PARKER BODINE
9 Assistant Administrator
10 Office of Enforcement and Compliance
11 Assurance

1 THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of
2 United States of America and the People of the State of California v. Plains All
3 American Pipeline, L.P. and Plains Pipeline, L.P.

4 FOR THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY:

5
6 2/26/2020

7 Date

8 
9 AMY C. MILLER
10 Region 9 Director
11 Enforcement and Compliance Assurance
12 Division
13 U.S. EPA Region 9
14 Mail Code ENF-1
15 75 Hawthorne Street
16 San Francisco, CA 94105

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*United States of America and the People of the State of California v.
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THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of *United States of America and the People of the State of California v. Plains All American Pipeline, L.P. and Plains Pipeline, L.P.*

FOR THE CALIFORNIA DEPARTMENT OF FISH and WILDLIFE:

3/4/2020
Date


THOMAS M. CULLEN, JR.
Administrator
Office of Spill Prevention and Response

United States of America and the People of the State of California v. Plains All American Pipeline, L.P. and Plains Pipeline, L.P.
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1 THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of
2 *United States of America and the People of the State of California v. Plains All*
3 *American Pipeline, L.P. and Plains Pipeline, L.P.*

4 FOR THE CALIFORNIA DEPARTMENT OF PARKS AND RECREATION:

5
6 3/2/20
7 Date

8 Lisa Ann L. Mangat
9 LISA ANN L. MANGAT
10 Director
11 California Department of Parks
12 and Recreation
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United States of America and the People of the State of California v.
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1 THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of
2 *United States of America and the People of the State of California v. Plains All*
3 *American Pipeline, L.P. and Plains Pipeline, L.P.*

4 FOR THE CALIFORNIA STATE LANDS COMMISSION:

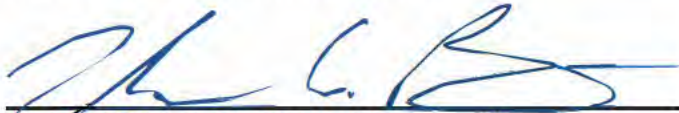
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6 2/28/2020
7 Date

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9 _____
10 JENNIFER LUCCHESI
11 Executive Officer
12 California State Lands Commission
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1 THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of
2 *United States of America and the People of the State of California v. Plains All*
3 *American Pipeline, L.P. and Plains Pipeline, L.P.*

4 FOR THE CALIFORNIA DEPARTMENT OF FORESTRY AND FIRE
5 PROTECTION'S - OFFICE OF THE STATE FIRE MARSHAL:

6 3/4/2020
7 Date



THOMAS W. PORTER

Director

California Department of Forestry and
Fire Protection

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United States of America and the People of the State of California v.
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1 THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of
2 *United States of America and the People of the State of California v. Plains All*
3 *American Pipeline, L.P. and Plains Pipeline, L.P.*

4 FOR THE CALIFORNIA REGIONAL WATER QUALITY CONTROL
5 BOARD, CENTRAL COAST REGION:

6 March 2, 2020

7 Date

8 

9 JOHN ROBERTSON
10 Executive Officer
11 Central Coast Regional Water
12 Quality Control Board

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United States of America and the People of the State of California v.
Plains All American Pipeline, L.P. and Plains Pipeline, L.P.

Consent Decree

1 THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of
2 *United States of America and the People of the State of California v. Plains All*
3 *American Pipeline, L.P. and Plains Pipeline, L.P.*

4 FOR THE REGENTS OF THE UNIVERSITY OF CALIFORNIA:

5
6 3/3/20
7 Date


BARTON LOUNSBURY
Senior Counsel
Office of the General Counsel

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11 Date

PEGGY FIEDLER
Executive Director
UC Natural Reserve System

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United States of America and the People of the State of California v.
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THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of *United States of America and the People of the State of California v. Plains All American Pipeline, L.P. and Plains Pipeline, L.P.*

FOR THE REGENTS OF THE UNIVERSITY OF CALIFORNIA:

Date

3 March 2020

Date

BARTON LOUNSBURY
Senior Counsel
Office of the General Counsel



PEGGY FIEDLER
Executive Director
UC Natural Reserve System

*United States of America and the People of the State of California v.
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THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of *United States of America and the People of the State of California v. Plains All American Pipeline, L.P. and Plains Pipeline, L.P.*

FOR PLAINS ALL AMERICAN PIPELINE, L.P.

2/25/2020
Date



HARRY PEANIS
President 

1 THE UNDERSIGNED PARTY enters into this Consent Decree in the matter of
2 *United States of America and the People of the State of California v. Plains All*
3 *American Pipeline, L.P. and Plains Pipeline, L.P.*

4 FOR PLAINS PIPELINE, L.P.

5
6 2/25/2020
7 Date

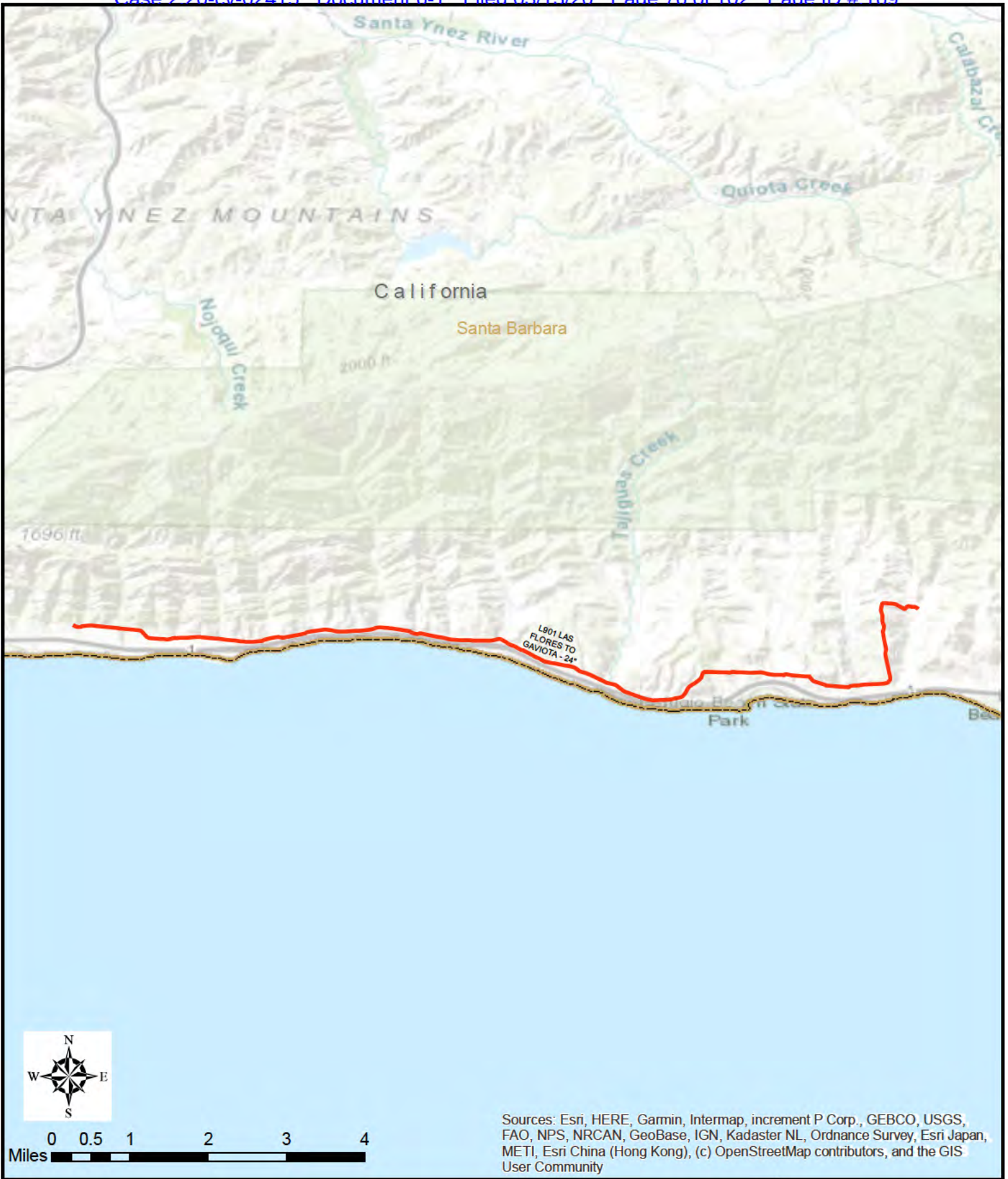
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HARRY PEFANIS
President *MBB*

APPENDIX A

*(Set of maps that generally depict Lines
901, 903, and 2000)*

*United States of America and the People of the State of California v.
Plains All American Pipeline, L.P. and Plains Pipeline, L.P.
Consent Decree*



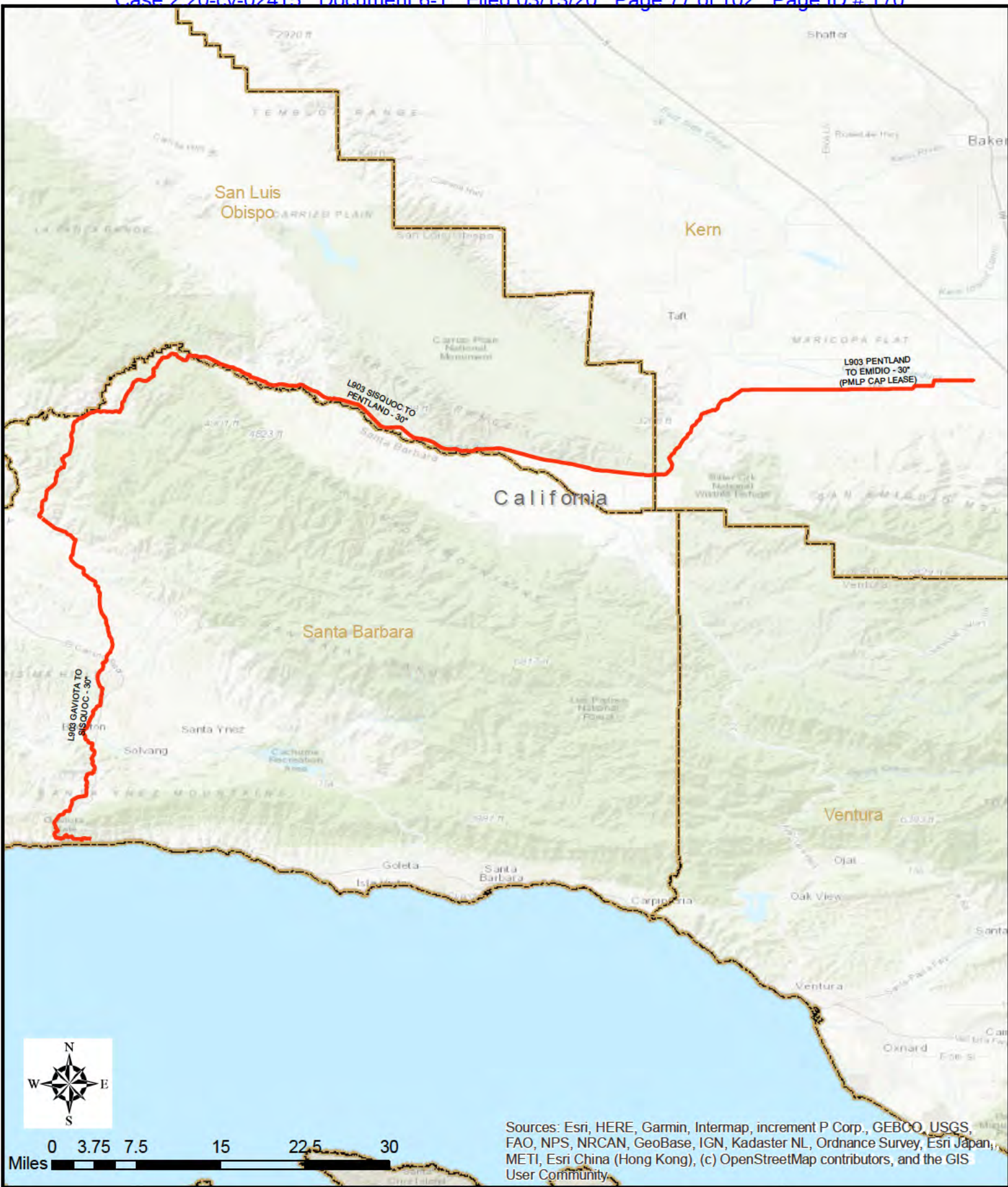
Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community

Scale: 1:100,000
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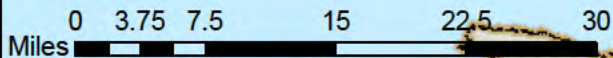
Appendix A – Line 901

Owner:

PLAINS
 ALL AMERICAN
 PIPELINE, L.P.



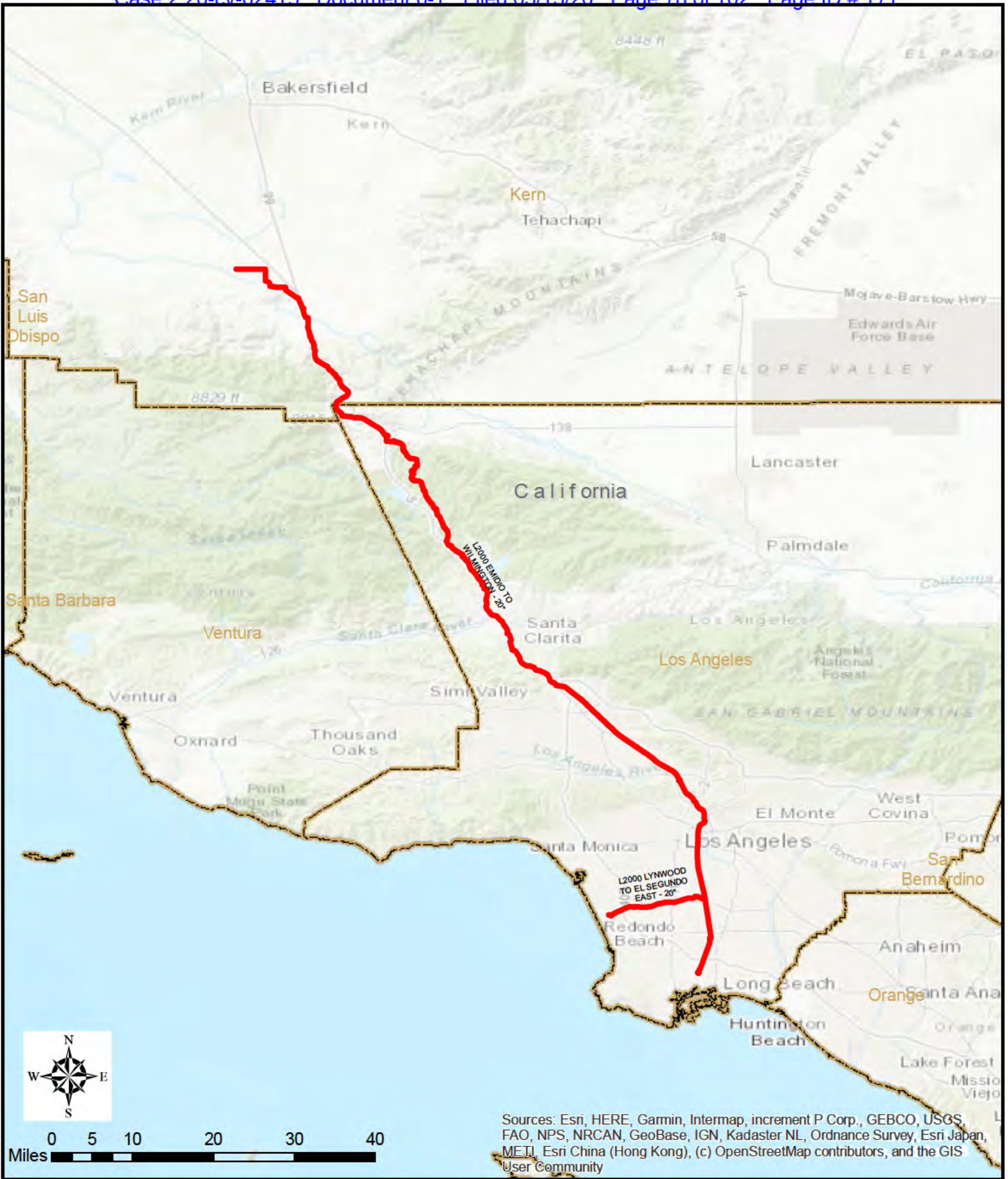
Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community



Scale: 1:700,000
 Sheet No: 1/1

Appendix A – Line 903





Sources: Esri, HERE, Garmin, Intermap, increment P Corp., GEBCO, USGS, FAO, NPS, NRCAN, GeoBase, IGN, Kadaster NL, Ordnance Survey, Esri Japan, METI, Esri China (Hong Kong), (c) OpenStreetMap contributors, and the GIS User Community

Scale: 1:966,574
 Sheet No: 1/1

Appendix A – Line 2000

Owner:

PLAINS
 ALL AMERICAN
 PIPELINE, L.P.

APPENDIX B
(PHMSA Injunctive Relief)

*United States of America and the People of the State of California v.
Plains All American Pipeline, L.P. and Plains Pipeline, L.P.
Consent Decree*

APPENDIX B

ARTICLE I – CALIFORNIA-SPECIFIC PROVISIONS

1. **State Waivers for Lines 901, 903, and 2000 (not to include any replacement lines):**
 - A. Prior to restarting Line 901, Plains shall apply for a State Waiver through the OSFM for the limited effectiveness of cathodic protection on Line 901. Plains must receive a State Waiver from the OSFM prior to restarting Line 901.
 - B. Prior to restarting non-operational segments of Line 903, Plains shall apply for a State Waiver through the OSFM for the limited effectiveness of cathodic protection on Line 903. Plains must receive a State Waiver from the OSFM prior to restarting Line 903.
 - C. Within 90 days of entry of the Consent Decree (CD), Plains must apply for a State Waiver through the OSFM for the limited effectiveness of cathodic protection on Line 903. The State Waiver shall apply to the currently operational segment of Line 903 from Pentland to Emidio.
 - D. Within 90 days of entry of the CD, Plains must apply for a State Waiver through the OSFM for the limited effectiveness of cathodic protection on Line 2000.
 - E. To the extent that a State Waiver directly incorporates terms identified in section 4 (Integrity Management) below, as being applicable to Lines 901, 903, or 2000, Plains shall not contest the inclusion of those terms in the relevant State Waiver. Plains reserves its rights to contest on any grounds any additional terms that the OSFM may require as part of each State Waiver if one is received. Nothing in this CD shall be construed to limit the authority of the OSFM to require additional terms or conditions in the State Waiver. Further, nothing in the State Waiver shall be construed to limit the applicability of the terms set forth in the CD.
2. **Replacement, Restart, or Abandonment of Lines 901 and 903:**
 - A. Plains shall replace the existing Line 901 and segments of Line 903 from Gaviota to Sisquoc and Sisquoc to Pentland with non-insulated pipe, if Plains is able to timely obtain: (1) agreements from shippers to transport sufficient quantities of product to make the cost of replacing the segments economically viable; (2) the Federal, State, and Local permits that may be required; and (3) whatever additional rights are needed, including rights-of-way that may be needed from landowners. Obtaining required commercial commitments, permits, rights-of-way, and any other rights necessary for replacement is the sole responsibility of Plains.

1. On any replacement segments of Lines 901 or 903, Plains shall, prior to commencing operation of such segment(s):
 - a. Test for potential AC/DC interference. Where potential AC/DC interference exists, proper mitigation of interference shall be designed and installed during construction of replacement lines.
 - b. Conduct a close interval survey (CIS) and AC/DC interference survey.
 - c. Based on the CIS and AC/DC interference surveys, place additional cathodic-protection test stations at locations where the surveys demonstrate potential cathodic-protection deficiencies, following review and consultation with the OSFM regarding proposed test station locations.
 - B. As an alternative to replacement of Line 901 and segments of Line 903 from Gaviota to Sisquoc and Sisquoc to Pentland, Plains may restart the existing pipelines in accordance with the CD (including Appendix D) and applicable law.
 - C. As an alternative to replacement or restart of Line 901 and segments of Line 903 from Gaviota to Sisquoc and Sisquoc to Pentland, Plains may abandon all or any segments in accordance with all applicable laws and regulations.
3. **Third-Party Analysis of Line 2000 ILI Data**
- A. Plains shall select, subject to OSFM's approval, a third-party consultant to review and analyze ILI data for Line 2000 and provide a report to the OSFM on its findings.
 - B. The consultant shall:
 1. Review all ILI results and reports that Plains has received from ILI vendors for Line 2000;
 2. Review Plains' processes and procedures for analyzing ILI data, and Plains' analysis of Line 2000 ILI results, and suggest potential improvements, if any, to Plains' current processes or procedures for analyzing ILI data;
 3. Analyze Plains' implementation of its ILI assessment procedures for Line 2000.
 4. Evaluate ILI vendor specifications to ensure that proper criteria and technology considerations are taken in to account in selecting the specific inspection tool(s) used in the future, with consideration given to best available technology for reliably detecting corrosion, general corrosion, selective seam-weld corrosion, and seam anomalies;

5. Consider disclosed industry standards and regulations, including, but not limited to: 49 CFR § 195.452, the California Elder Pipeline Safety Act, ASME B31.4 (Pipeline Transportation Systems for Liquids and Slurries), ASME B31G (Manual for Determining Strength of Corroded Pipelines) or RSTRENG, API 1160 (Managing System Integrity for Hazardous Liquid Pipelines), API 1163 (In-Line Inspection Systems Qualification), ANSI/ASNT ILI-PQ (In-Line Inspection Personnel Qualification and Certification), NACE SP0169 (Control of External Corrosion on Underground or Submerged Metallic Piping Systems), and the PRCI Pipeline Repair Manual;
 6. Comply with additional requirements specified in the scope of work.
- C. The third-party consultant shall prepare a written report reflecting its findings, conclusions, and any recommendations for improvement found in conducting the analysis.
1. The consultant may recommend improvements to Plains' ILI analysis process and procedures to improve the quality and integration of ILI data into its IMP going forward. Plains shall give due consideration to the results of the analysis and recommendations of the consultant but will maintain discretion over whether and how to implement any recommendations.
 2. The report shall include a list of documents and data reviewed in conducting the analysis, which shall be provided to the OSFM, if requested.
 3. Within 150 days of entry of the CD, the consultant shall provide a draft report to the OSFM and Plains for comment at the same time. Plains and the OSFM may provide comments to the consultant on the report within 21 days of receipt of the draft.
 4. Within 45 days after receiving comments (if any) from Plains and the OSFM, the consultant shall provide a final report to PHMSA, the OSFM and Plains.

4. **Integrity Management**

- A. For any operating segments of Lines 901, 903, and 2000 (not to include any replacement lines):
1. Plains shall implement the following measures and amend its IMP, as needed, to include the requirements of this section for the applicable lines:
 - a. In addition to other dig criteria specified by regulation or in its IMP, Plains shall remediate all internal or external metal loss anomalies that have an ILI reported depth of 40% or greater wall

loss, within one year of discovery. If Plains is unable to remediate such anomalies within one year of discovery, Plains shall notify OSFM and temporarily reduce the operating pressure and/or take further remedial action in accordance with 49 C.F.R. § 195.452 until the anomaly is remediated (or until otherwise authorized by OSFM).

- b. Analyze a sample of additional anomalies of varying amounts of metal loss between 10% and 40% for validation. The sample size shall be at least ten, unless fewer than ten anomalies are reported within that range, in which case Plains would examine the number of anomalies called.
- c. When sizing anomalies, apply interaction/clustering criteria of 6t by 6t for applicable ILI tools;
- d. Require its ILI tool vendor to include in the vendor's inspection report all metal loss anomalies of 10% or greater, based on raw data, prior to adding in any correction for tool tolerance;
- e. Any time a shrink sleeve is exposed during an anomaly investigation, remove the shrink sleeve, investigate circumferentially and longitudinally along the pipe for external corrosion and coating deterioration, and recoat with two-part epoxy;
- f. Send all field measurements to the tool vendor within 90 days of completing all digs for any ILI, provided that available data must be submitted prior to the next ILI run, and conduct annual meetings with the tool vendor to discuss tool performance;
- g. For any use of magnetic flux leakage (MFL) tools, require its ILI tool vendor to manually grade any metal loss anomalies initially identified by the ILI tool as greater than or equal to 20% of wall loss (i.e., have human eyes on the raw data and not simply rely on a computer algorithm), and require that the vendor's ILI report note any differences between what the computer algorithm reported and the vendor's manual grade;
- h. Where any ILI tool fails to record data for 5% or more of the external and/or internal surface area of the inspected segment, re-run the ILI tool to cover the area of failure;
- i. Integrate and analyze available data in its P&M process, including:
 - i. Assessment data from ILI tool runs;
 - ii. Dig and repair data;

- iii. Corrosion data, such as survey results, chemical treatments, and cleaning-pig results;
- iv. Operational data, such as pressure and flow data;
- v. Emergency response data, such as tactical response plans and results of recent drills on the pipeline, including locations of conduits to water, as identified in emergency response plans;
- vi. Evaluation of the capability of the leak detection system, which shall include identification of each leak detection segment between block valves, consideration of length and size of the pipeline, type of product carried, proximity to high consequence areas, swiftness of leak detection (the time period required for a leak to be operationally isolated and/or the pipeline to be shut down), type and location of valves, valve closure time, EFRD analysis results, the location of nearest response personnel, leak history, and risk assessment results;
- vii. Other pipeline characteristics, such as length, diameter, presence in HCAs and Environmentally and Ecologically Sensitive Areas (as defined in regulations promulgated pursuant to California Government Code § 8574.7(d), including 14 CCR 817.04(k)(3)(A)), maximum operating pressure, normal operating pressure, coating type, elevation data, water crossings, proximity to water bodies, casings, geohazard threats, maximum flow rate, and maximum rupture volume.

2. ILI Measures

- a. Initial ILI Runs. Each year during the first two years after entry of the CD, Plains shall conduct at least two ILIs using: (1) a high-resolution MFL tool; and (2) a UT tool with an inertial measurement unit (IMU). Plains shall compare both runs and evaluate all available information, including these tool runs and corresponding IMU data. If a UT tool run is unsuccessful, Plains shall identify the limitations that prevented the UT tool run from being successful, consider changes to increase the likelihood of a successful UT tool run, and use best efforts to rerun the UT tool within six months (subject to tool availability).
 - i. All ILI assessments in the first two years shall include a sizing tool and a tool capable of identifying dents.

- ii. In each of the first two years, Plains shall run the second ILI tool as soon as practicable after running the first ILI tool, but no later than 90 days after completion of the first ILI tool run. If one of the two tool runs is unsuccessful, Plains shall re-run the tool that was unsuccessful (but need not re-run the tool that was successful) even if the re-run of the unsuccessful tool run would occur more than 90 days from the successful tool run.
- b. Subsequent ILI Runs. After the first two years, Plains shall run at least one MFL or one UT tool every year, using a different ILI tool type (MFL or UT) in each alternating year. Alternatively, Plains may run a UT tool each year. If, however, any UT tool run is unsuccessful, Plains shall document the reasons why the UT tool was unsuccessful, consider changes to increase the likelihood of a successful UT tool run, and may use MFL technology to complete that year's ILI, but must run a UT tool the following year.
- c. All ILI Runs. Plains shall provide ILI results and reports to the OSFM within 30 days from its availability to Plains.

5. **Valves**

- A. Within one year after entry of the CD for any operating segments of Lines 901, 903, and 2000, and for any new pipeline segments replacing those lines, Plains shall conduct EFRD analyses, which shall include consideration of:
 - 1. Swiftiness of leak detection and pipeline shutdown capabilities, type of commodity carried, rate of potential leakage, volume that can be released, topography or pipeline profile, potential for ignition (for spilled commodity), proximity to power sources, location of nearest response personnel, specific terrain between the pipeline and the HCA, and benefits expected by reducing the spill size.
 - 2. Valve placement and method of valve actuation for all valves (not including valves used for instrumentation purposes, such as on tubing on transmitter calibration manifolds).
- B. Plains shall submit the EFRD analyses to OSFM within one year of entry of the CD.
- C. Where practical, Plains shall confirm that check valves that are necessary for the safe operation of the pipeline are in good working order at intervals required by other valve maintenance activities and associated procedures.

6. **Risk Analysis**

- A. For any operating segments of Lines 901, 903, or 2000 (not to include any replacement lines):
 - 1. Plains shall submit a risk analysis under proposed regulation 19 CCR § 2111(c) to OSFM (dated January 17, 2019 and publicly noticed in the California Regulatory Notice Register on February 15, 2019), or the final version of such regulation as it may be made effective in the future, regardless of whether or not those lines would otherwise be subject to the proposed regulations.
 - a. The information in the risk analysis shall be limited to the information listed in proposed regulation 19 CCR § 2111(c).
 - b. Plains' responsibility under this subsection is limited to providing the risk analysis to OSFM; Plains will maintain discretion over whether and how to implement the results of the analysis. The OSFM may review and comment on the risk analysis submitted by Plains consistent with provisions found in the proposed regulations, 19 CCR 2100 et seq.
 - c. The risk analysis shall be due within one year from entry of the CD.

7. **Leak Detection**

- A. For any operating segments of Lines 901, 903, or 2000 (not to include any replacement lines), Plains shall confirm in writing to the OSFM within 30 days of entry of the CD that it has installed a Computational Pipeline Monitoring (CPM) Real Time Transient Model (RTTM) that is compliant with API 1130.
- B. Within 12 months after initiating operation of any replacement lines for Lines 901 or 903, Plains shall verify and certify to the OSFM that all Pipeline and Instrumentation Drawings (P&IDs) reflect correct "as-built" information.

8. **Non-waiver**

- A. Nothing in this CD shall excuse Plains from otherwise complying with the AB 864 regulations when they are promulgated.

ARTICLE II – COMPANY-WIDE PROVISIONS ON REGULATED PIPELINES

9. **Integrity Management**

- A. New Procedures for Interim Reviews and Assessments

1. Plains shall modify Section 9.5 of its Integrity Management Plan (“Continual Evaluation and Assessment of Pipeline Integrity”) to provide for an annual, but not to exceed 15 months, Interim Review of each pipeline segment it operates to determine whether, since the last assessment (whether it was an Interim Assessment or a full periodic assessment under Section 6), conditions have changed or new information has been obtained that could significantly impact already-identified threats or create new threats for that segment. If so, Plains shall evaluate whether it should implement any P&M measure(s) to address that threat prior to the next regularly-scheduled assessment. Section 9.5 shall list all the categories of potential threats to be considered as part of the Interim Review and the types of conditions, information and data that will be included in the information analysis conducted under 49 CFR § 195.452(g).
2. Plains shall modify Section 9.5 of its IMP to provide new forms for P&M measures or actions to be taken as a result of an Interim Review. Section 9.5 shall provide that Plains’ Integrity Engineer may recommend any P&M measures that may be appropriate, including any P&M measures that could be recommended following a full assessment performed under Section 6 of its IMP.
3. Plains shall submit its proposed modifications of Section 9.5 to PHMSA no later than 60 days after entry of the CD. If PHMSA does not object or request any modification within 60 days, Plains shall proceed to implement the revised procedures in Section 9.5, which shall be completed within 18 months from entry of the CD.

B. Documentation for P&M Recommendations

1. Within 90 days from entry of the CD, Plains shall revise Part B of its P&M Recommendation form (F11-2), to expand the scope and content of comments in the “Basis of Recommendation” field to provide a narrative explanation that reflects, at a minimum:
 - a. What drew the engineer’s attention and caused him or her to make the recommendation (such as an anomaly, pattern, trend or potential correlation observed in the data, a particular event or occurrence, a particular change in the operation or configuration of the line or in its surrounding environment, “lessons learned” from another event or occurrence, a corporate goal or initiative, etc.);
 - b. The specific risk (likelihood or consequence of failure, or both) or concern that the recommended measure is intended to investigate or address; and

- c. The goal or intended outcome that the recommended P&M measure is intended to achieve with regard to that specific risk or concern.
 2. In the new forms for the Interim Review procedure described in Paragraph A above, Plains shall likewise provide a narrative explanation of the bases for any recommended P&M measures.
 3. In Part B of its Preventive and Mitigative Evaluation Recommendation Form (F11-2), Plains shall continue to identify the anticipated completion date for the P&M measure in the column titled "Deadline Date."
- C. Tracking of P&M Measures

Plains shall document P&M measures recommended but not implemented. Plains shall document implemented P&M measures through to completion, whether undertaken pursuant to an Interim Review under Section 9.5 or a full assessment under Section 6, such that these actions will be properly documented under 49 CFR § 195.452(l).

10. **Valves and O&M**

- A. Within two years after entry of the CD, Plains shall conduct EFRD analyses for all Regulated Pipelines for which it has not previously completed an EFRD analysis.
- B. Within two years of entry of the CD, Plains shall develop and implement procedures to:
 1. If a valve fails to respond properly on first actuation command, document the failure and review historical records for that valve to identify any systemic issues.
 2. Adjust Plains' surge analyses and Emergency Response Plans, if necessary, to account for identified systemic issues associated with valve closure times.
 3. Timely communicate to the Control Room the status of valve maintenance activity for those valves on Regulated Pipelines that are capable of being operated by the Control Room.
 4. Verify that personnel assigned to operator-qualification tasks for valve maintenance are qualified to perform those tasks.
- C. Plains shall make all repairs necessary to keep valves in good working order within one year of discovery that the valve is not operating as intended, or, if not possible, Plains shall provide timely notification (including justification) to PHMSA or OSFM as applicable.

- D. For all field personnel who perform maintenance on facilities, equipment, or devices, Plains shall provide training:
 - 1. Within two years of entry of the CD, that addresses the importance of complying with Plains' policy requiring notification of Control Room personnel before beginning maintenance activities on any such facility, equipment, or device that could change the status of any pump, valve, CPM device, SCADA device, pressure or flow metering or rate that is monitored by the Control Room. Plains shall include in the training a requirement that employees shall notify the Control Room before entering a facility to perform maintenance, or, if not possible, immediately after entering.
- E. Plains shall improve existing valve maintenance recordkeeping to include confirmation whether the valve has been actually operated during maintenance.

11. **Leak Detection**

- A. Within 90 days after entry of the CD, Plains shall create and maintain a list of its regulated mainline pipelines, excluding gathering lines and Delivery Lines, to indicate which of the following three rupture-detection methods, if any, are used on each line: (1) Rate of Change Combination alarm; (2) low discharge pressure alarm; or (3) 5-minute computational pipeline monitoring (CPM) alarm.
 - 1. Within one year after entry of the CD, for any regulated mainline pipeline identified in the list created pursuant to this paragraph that does not utilize at least one of the three rupture detection methods, Plains shall implement at least one.
- B. For the term of the CD, Plains shall conduct annual training for controllers on attributes and benefits of various methods of leak detection, including Analog High/Low Threshold, Alarm Deadband, Creep Deviation, and Analog Rate of Change.
- C. Within 18 months of entry of the CD, for its CPM systems, Plains shall analyze and evaluate the use of accumulated deviation rolling time periods longer than 24 hours.
 - 1. Plains shall document its analysis and provide it to PHMSA for comment, but Plains shall maintain discretion over what actions to take, if any, and how to implement the results of its analysis.
- D. Within six months of entry of the CD, Plains shall have in place a written procedure for Selection of Leak Detection Method for its Regulated Pipelines.
 - 1. Plains shall provide the Selection of Leak Detection Method procedure to PHMSA for comment, but Plains shall maintain discretion over and be

responsible for the final content and implementation of the Selection of Leak Detection Method procedure.

- E. Plains will hold periodic (at least annual) meetings to solicit feedback from Control Room and operations maintenance personnel regarding potential improvements to leak detection. The results of the meetings will be documented and shared with appropriate personnel. The recommendations will be evaluated and documented.
- F. Instrumentation and Display
 - 1. To minimize and prevent false operating conditions from being displayed, Plains shall, per API 1175 (Pipeline Leak Detection – Program Management (1st Edition, December 2015)), within three years from entry of the CD or such earlier time as required by regulations:
 - a. Provide a procedure by which operations maintenance personnel and/or Control Room personnel identify and record when instrumentation has been impeded on an unplanned basis and is no longer providing accurate and updated values on pressure, flow, or temperature due to scheduled or planned maintenance activities.
 - b. Track these conditions through to resolution, including instrumentation relocation when necessary.

12. **Control Room Management**

- A. For Lines 901 and 903, prior to resuming operations on segments currently not in service or commencing operations on any replacement for those lines, Plains shall:
 - 1. Complete point-to-point verification reviews for all components of its SCADA system, including displays, alarm setpoint values, and alarm log descriptors;
 - 2. Update its piping and instrumentation diagrams, software, manuals, and operating procedures to accurately reflect the existing field configuration;
 - 3. Confirm that all Lo-Lo and Hi-Hi SCADA alarms are configured and programmed as critical safety related alarms for pressures and flows, and that alert notifications are correct and accurate; and
 - 4. Update the names of all facilities, equipment, devices, measurement points and locations in console displays, the Control Room Management Plan and Control Center General Procedures, shift reports, and form templates to reflect current operating conditions (updating or removing out-of-date names).

- B. For Line 2000, within six months after entry of the CD, Plains shall confirm to the OSFM that all Alarm Descriptors on the control console are accurate.
- C. Plains shall implement the Control Room Management Plan measures and Control Center General Procedures measures referenced in paragraph 23(a) of the CD.

13. **Emergency Response and Oil Spill Response Plans**

A. California-Specific Provisions:

- 1. Plains shall review and update its Bakersfield District Response Zone Plan periodically, as required by applicable regulations, including 14 CCR 816.05. Plains' review shall include the portions of its Response Plan that address identification of culverts along the pipelines' rights-of-way, potential receptors, access to potential spill sites, and procedures to assure protection of the environment from oil spills. To the extent that Plains has a Tactical Response Plan, Plains shall make it available to the Governments upon reasonable request and as needed in connection with a drill or response to a spill.

B. Company-Wide Provisions

- 1. Plains shall, at least once before two years from the date of entry of the CD, and at least one additional time prior to termination of the CD, survey its rights-of-way for all regulated mainline pipelines of at least 24" diameter, by foot or air patrol, to identify all culverts and shall ensure the emergency response plans covering those pipelines (a) reflect the locations of all culverts identified, and (b) address potential containment and recovery techniques for spills that may occur near identified culverts.
- 2. Within 180 days of entry of the CD (or within 180 days of a new employee being hired, or an existing employee being assigned to relevant duties) Plains shall provide or confirm that it has provided all employees who may reasonably be involved in spill response with NIMS ICS training at the 100 and 200 levels. Within 180 days of entry of the CD, Plains shall also provide or confirm that it has provided ICS training at the 300 and 400 level to any employee who may reasonably be expected to coordinate with the Incident Management Team during a spill response. Plains shall provide refresher training to employees within two years after initial training and shall maintain certification of such training and make such documents available to Plaintiffs upon request.
- 3. Going forward from the date of the CD, Plains shall include in its contracts with all Oil Spill Response Organizations (OSROs) a requirement that the OSROs' employees and contract employees receive training at the same level specified for Plains employees, based on their responsibilities, prior to participating in any incident response on behalf of

Plains. Plains shall require its OSRO contractors and subcontractors to register with a third-party online compliance verification system and shall use that online verification system to spot-check the NIMS ICS Training histories for randomly-selected OSRO personnel who participate in Plains' table-top drills. Plains' spot-check shall include a reasonable number of OSRO personnel participating in the drills to help ensure that all OSRO personnel participating in incident response are trained at the ICS levels specified herein.

4. Within 180 days of entry of the CD, Plains shall provide or confirm that it has provided all Control Room supervisors with training regarding the Control Room's emergency response responsibilities and procedures. Plains shall provide this training annually thereafter. Plains shall maintain auditable documentation that supervisors have received such training and shall make such documentation available to PHMSA upon request.
5. Plains shall notify PHMSA (and, for California Lines, California OSPR and OSFM) of company-sponsored and organized drills in accordance with applicable regulations, including table tops (either with or without equipment deployment). Plains shall provide PHMSA (and, for California Lines, California OSPR and OSFM) with after-action reports for each table-top drill involving equipment deployment within 90 days of completion of the drill. Plains shall include lessons learned in such after-action reports and shall consider such lessons learned for incorporation into future drills or exercises.
6. For the term of the CD, a representative of Plains' Control Room management team shall participate in any after-action or "hot wash" activity designed to identify areas of improvement following a release, and shall share, in documented form, the information obtained with relevant Control Room personnel.

14. **Safety Management System (SMS)**

- A. Plains shall continue to implement its SMS, which is based on recommended practices in American Petroleum Institute (API) RP 1173 (Pipeline Safety Management Systems (1st Edition, July 2015)).
 1. Prior to the termination of the CD, Plains shall hire a third party to assess the conformance of its SMS to API RP 1173. Plains shall direct the third party to transmit a copy of the final report to PHMSA. Plains' responsibility under this paragraph shall be limited to engaging the third party to prepare the report and providing the report to PHMSA. Any nonconformance identified by the third party shall not be a violation of the CD.

- B. Plains shall participate in the API Pipeline SMS Group to exchange ideas, information, and lessons learned about implementation of API RP 1173.

15. **Drug and Alcohol Program**

- A. Within one year of entry of the CD, Plains shall review and revise its drug and alcohol misuse plans to comply with post-accident and random drug and alcohol testing required by 49 C.F.R. §§ 199.105(b), (c), and 49 C.F.R. § 199.225(a). This shall include a review of all covered positions among Control Room personnel and field personnel for inclusion in the plans for post-accident testing. Covered positions shall include any person with authority to shut down a pipeline, including Control Room shift supervisors. Plains shall ensure adequate implementation and documentation for all post-accident drug/alcohol tests as required by 49 C.F.R. § 199.117(a)(5) and 49 C.F.R. §§ 199.227(b)(4), (c)(1)(v) and in accordance with its procedures. Should Plains determine that it is not possible to administer a post-accident drug/alcohol test on a covered employee whose performance of a covered function either contributed to the accident or could not be completely discounted as a contributing factor within the time specified in the regulations, Plains shall document why the test was not administered within such time.

APPENDIX C

(Intentionally left blank)

*United States of America and the People of the State of California v.
Plains All American Pipeline, L.P. and Plains Pipeline, L.P.
Consent Decree*

APPENDIX D

*(Remaining Corrective Actions from the
PHMSA CAO)*

*United States of America and the People of the State of California v.
Plains All American Pipeline, L.P. and Plains Pipeline, L.P.
Consent Decree*

APPENDIX D

1. All outstanding corrective actions in PHMSA's closed Corrective Action Order (CAO), CPF No. 5-2015-5011H, as amended, are hereby merged into this Consent Decree, as outlined below, and subject to the sole regulatory oversight of the OSFM.

- a. **Line 901 Shutdown.** Plains shall not operate Line 901 until authorized to do so by the OSFM.
- b. **Restart Plan for Line 901.** If Plains seeks to restart Line 901, Plains shall develop and submit, at least 60 days in advance of a scheduled restart, a written Restart Plan for Line 901 to the OSFM for review and approval. Once approved by the OSFM, the Restart Plan shall be incorporated by reference into this Consent Decree. The Restart Plan shall include:
 - 1) Documentation of the completion of all mandated actions, and a management of change plan to ensure that all procedural modifications are incorporated into Plains' operations and maintenance procedures manual;
 - 2) Provisions for adequate patrolling of Line 901 during the restart process and shall include incremental pressure increases during start-up, with each increment to be held for at least two hours;
 - 3) Sufficient surveillance of the pipeline during each pressure increment to ensure that no leaks are present when operation of the line resumes;
 - 4) A specific day-light restart that includes advance communications with local emergency response officials;
 - 5) Master Control Room enhancements, including:
 - a) Implementation of advanced leak-detection

capabilities that include mass balance and line pack calculations (the total volume of liquid present in a pipeline section). The leak-detection improvements shall include:

1. Revised alarm threshold adjustments;
 2. Additional required instrumentation; installation of additional safety valves as a result of Plains' EFRD evaluation;
- b) Review and update of the alarm set-point values of pressures and flows to account for hydraulics and the interaction of topography, pipeline status (running and shutdown), sensor location, and historical pressure and flow values by configuration, in order to provide a basic level of leak detection when the pipeline is down and not running. Dynamic alarm limits based on pipeline status shall be used if hydraulically required;
- c) Implementation of modifications to the existing alarm priority/severity system to incorporate low and high pressure and flow values in major or safety-related alarm (SRA) categories;
- d) Implementation of emergency shutdown programming associated with Line 901 that can be executed by the Shift Supervisor or Controller;
- e) Development and implementation of training associated with the emergency shutdown programming described above; and
- f) Provision of additional controller training that

incorporates awareness of abnormal operations and reduced-pressure operational characteristics, including alarm set-point revisions for conditions similar to the Refugio Incident.

- 6) Elimination and documentation of actions taken to prevent inappropriate uncommanded Valve 460 (Sisquoc Conoco) status and position changes;
- 7) Installation of additional safety valves as a result of Plains' EFRD evaluation;
- 8) Installation of additional pressure sensors as a result of Plains' surge study;
- 9) Initiation of a UT ILI within seven days after steady-state operation is achieved in accordance with an ILI schedule approved by the OSFM. The tool run shall be initiated during daylight hours. If the tool run does not collect a complete data set, the UT tool shall be promptly re-run. A report from the ILI tool vendor shall be completed within 30 days of running the tool. Plains shall complete its review and analysis of the ILI report within 15 days of receiving the report. Provisions shall be made to address any immediate repairs that result from an initial data analysis of the UT ILI run; and
- 10) **Corrosion Prevention.** Plains shall include a long-term plan to address corrosion under insulation (CUI) on Line 901 that meets the requirements of 49 C.F.R. Part 195, Subpart H, in any Restart Plan. Plains may address the inadequate corrosion prevention through any method approved by the OSFM, including but not limited to the provisions contained in CAO Amendment No. 3, Section 2(a)-(c).

- c. **Return to Service of Line 901.** After the OSFM approves the Restart Plan, Plains may return Line 901 to service but the operating pressure shall not exceed eighty percent (80%) of the actual operating pressure in effect immediately prior to the Refugio Incident on May 19, 2015.
- d. **Removal of Pressure Restriction of Line 901.** The OSFM may allow the removal or modification of the pressure restriction upon a written request from Plains demonstrating that restoring the pipeline to its pre-Refugio Incident operating pressure is justified, based on a reliable engineering analysis showing that the pressure increase is safe, considering all known defects, anomalies, and operating parameters of the pipeline. The OSFM may allow the temporary removal or modification of the pressure restriction upon a written request from Plains demonstrating that temporary Preventive and Mitigative (P&M) measures will be implemented prior to and during the temporary removal or modification of the pressure restriction. The OSFM's determination shall be based on consideration of the Refugio Incident's cause and Plains' evidence that P&M measures provide for the safe operation of Line 901 during the temporary removal or modification of the pressure restriction.
- e. **Line 903 Shutdown.** After purging Line 903, Plains shall not operate Line 903 between Gaviota and Pentland stations until authorized to do so by the OSFM.
- f. **Restart Plan for Line 903.** If Plains seeks to restart the Gaviota-to-Pentland segment of Line 903, Plains shall develop and submit, at least 60 days in advance of a scheduled restart, a written Restart Plan for the Gaviota-to-Pentland segment of Line

903 to the OSFM for review and approval. Once approved by the OSFM, the Restart Plan shall be incorporated by reference into this Consent Decree. In addition to all the requirements set forth in the above subparagraphs 1.b.1)-11), excluding subparagraph 1.b.6), the Restart Plan shall include:

- 1) Provisions for adequate patrolling during the restart process and the inclusion of incremental pressure increases during start-up, with each increment to be held for at least two hours;
- 2) Sufficient surveillance of the pipeline during each pressure increment to ensure that no leaks are present when operation of the line resumes; and
- 3) Provisions for a daylight restart and advance communications with local emergency response officials.

g. Line 903 Return to Service. After the OSFM approves the Restart Plan for the Gaviota-to-Pentland segment of Line 903, Plains may return that segment to service, but the operating pressure shall not exceed eighty percent (80%) of the highest pressure sustained for a continuous 8-hour period between April 19, 2015, and May 19, 2015, for Line 903 (Gaviota-to-Sisquoc and Sisquoc-to-Pentland segments).

h. Removal of Pressure Restriction for Line 903. After a return to service, Plains may request the OSFM to remove the pressure restriction for the Gaviota-to-Pentland segment of Line 903.

- 1) The OSFM may allow removal or modification of the pressure restriction upon a written request from Plains demonstrating that restoring the pipeline to its pre-Refugio Incident operating pressure is justified, based on a reliable

engineering analysis showing that the pressure increase is safe, considering all known defects, anomalies, and operating parameters of the pipeline.

2) The OSFM may allow the temporary removal or modification of the pressure restriction upon a written request from Plains demonstrating that temporary P&M measures will be implemented prior to and during the temporary removal or modification of the pressure restriction. The OSFM's determination shall be based on consideration of the Refugio Incident's cause and Plains' evidence that P&M measures provide for the safe operation of Line 903 during the temporary removal or modification of the pressure restriction. Requests for removal of the pressure restriction may be submitted by pipeline segment.

- i. **Notifications.** Plains shall provide notification to the OSFM within five business days of any of the following events: any investigation and remediation field actions for identified anomalies (i.e., digs and repairs), ILI tool runs, and/or startup dates.
- j. **Reporting Requirements for Lines 901 and 903.** If and when Plains has concluded all items in this Appendix D, Plains shall submit a final Appendix D Documentation Report to the OSFM for review and approval.
 - 1) The OSFM may approve the Appendix D Documentation Report incrementally without approving it in its entirety.
 - 2) Once approved by the OSFM, the Appendix D Documentation Report shall be incorporated by reference into this Consent Decree.

3) The Appendix D Documentation Report shall include but not be limited to:

- A. Table of Contents;
- B. [*intentionally left blank.*]
- C. [*intentionally left blank.*]
- D. Summary of all tests, inspections, assessments, evaluations, and analysis to the extent required under this Appendix D;
- E. [*intentionally left blank.*]
- F. [*intentionally left blank.*]
- G. Lessons learned while fulfilling the requirements of this Appendix D.

EXHIBIT E



DEPARTMENT OF FORESTRY AND FIRE PROTECTION
OFFICE OF THE STATE FIRE MARSHAL
P.O. Box 944246
Sacramento, California 94244-2460
(916) 568-3800
Website: www.fire.ca.gov



CERTIFIED MAIL No: 9589-0710-5270-1475-5353-08

December 17, 2024

Lance Yearwood
Vice President
Sable Offshore Corp
845 Texas Avenue, Suite 2920
Houston, Texas 77002

SUBJECT: LETTER OF DECISION ON THE STATE WAIVER REQUEST FOR LIMITED EFFECTIVENESS OF CATHODIC PROTECTION ON THERMALLY INSULATED PIPELINE AND CORROSION OF OR ALONG A LONGITUDINAL SEAM WELD (CA-324)

Operator: Sable Offshore Corp
OPID# 40851
845 Texas Avenue, # 2920
Houston, Texas 77002

Pipeline: OSFM Line ID 0015 - 10.86 miles (Las Flores Canyon to Gaviota) of Sable Offshore Corp CA-324 (OSFM Line ID 0015) located in Santa Barbara County, California as described in the request of state waiver dated April 24, 2024

Dear Mr. Yearwood:

The Office of the State Fire Marshal (OSFM) received Sable Offshore Corp's (*Sable*) state waiver request (*Application*) on April 24, 2024, in accordance with the terms of the Consent Decree (CD) between Plains Pipeline, L.P. and the United States of America and the People of the State of California, DOJ Case REF. NO. 90-5-1-1-1130 (Appendix B, Article 1.1.D).

In addition, Sable requested a regulatory relief from Title 49 Code of Federal Regulations (49 C.F.R.), § 195.452(h)(4)(iii)(H) *Corrosion of or along a longitudinal seam weld* for Sable CA-324.

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Sable explained that its goal is to appropriately manage the risk of corrosion under insulation that may occur as a result of inadequate cathodic protection due to the shielding effects of the polyurethane foam and the polyethylene tape wrap. Sable described the measures it has taken to address this risk and implemented and proposed a number of additional measures designed to mitigate the risk of corrosion under insulation that may result from potential ineffective cathodic protection (CP).

Sable provided the OSFM with its proposed measures to mitigate the risk of corrosion under insulation. Sable also provided the OSFM information from the completed in-line inspections and additional data requested by our office. The OSFM Pipeline Safety Engineers have reviewed the materials provided and have been in communication with the United States Department of Transportation (USDOT), Pipeline and Hazardous Materials Safety Administration (PHMSA) Engineering and Research Division to incorporate PHMSA's recommended conditions into the state waiver.

The OSFM has regulatory jurisdiction over the safety standards and practices of intrastate hazardous liquid pipeline transportation within California. As a Pipeline Safety Program that is certified under 49 USC § 60105, the OSFM may grant a state waiver with a pipeline safety regulation adopted by the state of California. Title 49 C.F.R., Part 195 was adopted by reference as it relates to hazardous liquid pipelines within Title 19 California Code of Regulations (19 CCR), Section 2000.

This state waiver applies to Sable's Line CA-324 (OSFM Line ID 0015) which consists of a 10.86 mile long, 24-inch outside diameter pipeline segment with the origin and termination points as described in the application. The pipeline is located in Santa Barbara, California and shall be referred herein as CA-324.

The state waiver shall not become effective until (1) PHMSA issues an Order approving the waiver or stating it has no objection to the waiver or (2) PHMSA takes no action on the waiver within sixty (60) days after receiving the Letter of Decision from the OSFM.

The state waiver is limited to a term of no more than ten (10) years from the date it becomes effective, which shall be considered as the date of issuance. The OSFM may terminate the state waiver under conditions detailed below.

Applicable Regulations

The OSFM hereby grants this state waiver for CA-324, provided that Sable complies with the specific requirements in this state waiver and any additional conditions outlined by PHMSA. The pipeline must be operated and maintained in accordance with the CD, these state waiver conditions and 49 C.F.R. Part 195, with the exception of 49 C.F.R. §195.452(h)(4)(iii)(H). In the event of a conflict between the state waiver conditions and the applicable requirements under 49 C.F.R. Part 195, the state waiver conditions control.

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Should additional federal or State statutory or regulatory requirements come into effect following the implementation of this state waiver, CA-324 shall be subject to those requirements except where they are in conflict with the State Waiver or the safe operation of the pipeline.

General Conditions

1. The pipeline can only be used to transport crude oil as stated in the application.
2. The maximum operating pressure (MOP) of CA-324 cannot exceed 1003 pounds per square inch gauge (psig).
3. The maximum operating temperature of the crude oil that transports in CA-324 must not exceed 140 Fahrenheit for more than 12 consecutive hours.
4. Prior to startup, Sable must develop and implement procedures for the conditions and requirements described in the state waiver.
5. This state waiver does not relieve Sable from other requirements under 49 C.F.R. Part 195 or the Elder California Pipeline Safety Act of 1981 other than contained herein.
6. This state waiver does not relieve Sable from any requirements imposed by the Consent Decree (United States District Court Central District of California Civil Action No. 2:20-cv-02415).
7. In-line inspection must include:
 - a. Use of a tool that is at least capable of reliably detecting and identifying cluster corrosion and general corrosion. Definition of cluster and general corrosion is as follows:
 - i. Cluster means two or more adjacent metal loss features in the wall of the pipe or weld that may interact based on interaction criteria.
 - ii. General corrosion means uniform or gradually varying loss of wall thickness over an area.
 - b. Use of a tool that is at least capable of reliably detecting and sizing corrosion at a 90 percent probability of detection (POD) and probability of identification (POI).
 - c. Use of a tool that is at least capable of reliably detecting and sizing cracks or crack-like anomalies at a 90 percent POD and POI.
8. Prior to placing CA-324 in operation, Sable must perform fracture toughness tests on the existing 24" pipe from CA-324 in accordance with ASTM E1820-23B Standard Test Method for Measurement of Fracture Toughness. All of the test specimens must be from the predominant existing 24" pipe, specifically API 5L X65 HF-ERW pipe with a nominal thickness of 0.344" that was manufactured by

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Nippon Steel Corp. in the 1980s. At least three (3) separate tests must be performed to obtain the fracture toughness values of the pipe body, heat affected zone (HAZ)¹, and the HF-ERW long seam weld on the pipe to represent the fracture toughness of its CA-324 (i.e. three (3) samples for pipe body, three (3) samples for HAZ, and three (3) samples for the HF-ERW long seam weld). The lowest fracture toughness value must be applied to conditions 10, 30, 33, and 48. Sable may use pipe samples taken opportunistically during ongoing pipeline maintenance and repair efforts.²

9. All immediate and 180-day repair conditions that are listed in this state waiver must be evaluated and remediated prior to restarting CA-324. Sable must utilize Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) tools within seven (7) days of achieving initial steady state operation in accordance with an ILI survey schedule approved by OSFM. Sable must utilize the most recent Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) results when identifying these repair conditions.
10. Remaining strength of pipe calculation for all metal loss anomalies must be in accordance with the Modified B31G method as described in ASME B31G *Manual for Determining the Remaining Strength of Corroded Pipelines*. If ASME B31G 2012 Edition is used, then it must comply with the conditions in accordance with Section 1.2 and exclusions in accordance with Section 1.3 of ASME B31G 2012 Edition. However, if the metal loss anomaly intersects or is within one (1) inch (circumferentially) of the longitudinal seam weld, Sable must also calculate the predicted failure pressure of the anomaly by using the crack-like flaw evaluation method ASME FFS-1/API 579-1.
11. Sable must utilize cleaning pigs at regular intervals not to exceed a biweekly basis to maintain adequate cleanliness on the internal pipe wall of its CA-324.

Pressure Testing

12. Prior to placing the pipeline in operation, Sable must conduct a spike hydrostatic pressure test of the state waiver pipeline segments at a minimum pressure that is at least 1.5 times the MOP or 100% SMYS, for a minimum of 15 minutes after

¹ The heat affected zone (HAZ), as used in the state waiver, is defined as a 1-inch-wide area on either side of the longitudinal weld seam.

² Sable must submit all fracture toughness results to the OSFM prior to restarting the pipeline.

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- the spike test pressure is stabilized. Sable must field evaluate and remediate the following anomalies before performing the spike hydrostatic test on CA-324:
- a. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.
 - b. All anomalies that have a predicted failure pressure less than or equal to 1.6 times MOP.
13. Immediately following the spike hydrostatic pressure test, Sable must conduct an 8-hour hydrostatic pressure test of the state waiver pipeline segments at a minimum of 1.25 times the MOP.
 14. Sable must obtain the Test ID from the OSFM for each hydrostatic pressure test and have the approved independent testing firm forward separately the certified test results to the OSFM.
 15. Each hydrostatic pressure test must be performed in accordance with the applicable requirements of 49 C.F.R., Part 195 Subpart E – Pressure Testing and monitored by an independent testing firm listed under the OSFM approved hydrostatic testing companies.
 16. Failures resulting from the spike hydrostatic pressure test or the 8-hour strength test shall be immediately reported³ to the OSFM via email at PipelineNotification@fire.ca.gov
Subject: OSFM State Waiver - Hydrotest Failure
 17. Section(s) of the state waiver pipeline segments that failed during the required hydrotesting must be repaired by removing and replacing the failed section. The OSFM reserves the right to revoke the state waiver if failure(s) raise the concern that the pipeline cannot be safely operated.

In-Line Inspection (ILI) Assessment and Frequency

18. At least 90 days prior to performing in-line inspections of the state waiver segment, Sable shall provide the OSFM with a written notification to PipelineNotification@fire.ca.gov describing its assessment plan with the following information:
 - a) Dates for integrity assessment
 - b) In-line inspection tool(s) selected, in accordance with API Standard 1163 Section 5 and NACE SP0102⁴ to assess the integrity of the subject pipe

³ In addition to the OSFM reporting, Sable shall follow all additional state reporting requirements.

⁴ Industry standards that are referenced in this state waiver must utilize the editions that are incorporated by referenced in Title 49 Part 195.3 unless another edition was explicitly specified.

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- segment(s) in which ILIs must be capable to detect and size wall loss, dents, internal corrosion, external corrosion, cracks and crack-like indications
- c) In-line inspection tool vendor(s)
 - d) Required tool specifications including operational specifications and anomaly sizing tolerances
 - e) Tool validation methodology
 - f) Anomaly feature identification criteria and reporting thresholds – wall loss, dents, internal corrosion, external corrosion, cracks, and crack-like indications
 - g) Criteria used to identify locations for excavation and field verification
 - h) Non-destructive examination
19. Within seven (7) days prior to any anticipated ILI tool run, Sable must utilize extensive brush pigs and solvents (xylene or other chemicals) to ensure that the internal pipe wall does not have any corrosive products, wax, and bacteria buildup that may affect the ILI tool performance.
20. Metal Loss Tool(s)
- a. Initial ILI tool runs – Each year, during the first two (2) years of operating CA-324, Sable shall conduct at least two (2) ILIs using a UTWM tool with an inertial measurement unit (IMU). Sable shall compare both runs and evaluate all available information, including these tool runs and corresponding IMU data. Sable shall perform the UTWM tool run every six (6) months not to exceed nine (9) months. If a UTWM tool run is unsuccessful, Sable shall identify the limitations that prevented the UTWM tool run from being successful, consider changes to increase the likelihood of a successful UTWM tool run, and use best efforts to rerun the UTWM tool within 30 days.
 - b. Subsequent ILI tool runs – After the first two (2) years of operating CA-324, Sable shall conduct at least one (1) Ultrasonic Wall Measurement tool (UTWM) each calendar year, not to exceed 15 months or the ILI assessment must be assessed at more frequent intervals if the remaining Failure Pressure Ratio will be less than 1.39 times MOP prior to the next ILI assessment, based upon anomaly growth estimates and pressure cycling. If any UTWM tool run is deemed to be unsuccessful, Sable shall document the reasons why the UTWM tool was unsuccessful, consider changes to increase the likelihood of a successful UTWM tool run, and must reassess the pipeline within 30 days after it was deemed to be unsuccessful. All metal loss tool runs must also utilize an Inertial Measurement Unit (IMU).
21. Crack Detection Tools - Sable shall conduct at least one (1) Ultrasonic Shear Wave Crack Detection (USCD) tool each calendar year, not to exceed 15

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months⁵ or ILI assessment must be assessed at more frequent intervals if condition 48 determined a shorter assessment interval.

- a. These crack tool runs must utilize an Inertial Measurement Unit (IMU) and must be able to detect and size axial and circumferential cracks.
 - b. USCD Performance Specification Requirements
 - i. The USCD tools must have a probability of detection that is $\geq 90\%$ for axial and circumferential cracks.
 - ii. The minimum crack depth that can be detected must be at least 1 mm for axial and circumferential cracks that are located in the base material.
 - iii. The minimum crack depth that can be detected must be at least 2 mm for axial and circumferential cracks that are located in the weld.
 - iv. The depth sizing accuracy for cracks must be ± 0.8 mm for axial cracks and ± 1 mm for circumferential cracks.
22. Dents and Pipe Deformation: Sable shall conduct a high-resolution deformation ILI tool with each UTWM.
23. Where any ILI tool fails to record data for 5% or more of the external and/or internal surface area of the inspected segment, reassess with the ILI tool to cover the area that is deemed to be inadequate data of the inspected segment. In addition, if the ILI tool travels at a speed that is outside the range of the tool velocity listed in the tool specification for 2% or more of the length of the inspected segment, Sable must rerun the ILI tool to reassess the pipeline segment in which the ILI tool velocity was outside of the specified tool velocity range.
24. All ILI tool runs must obtain the Test ID from the OSFM prior to run.
25. Sable must require its ILI tool vendor(s) to include in the vendor's inspection report all metal loss indications of 10% or greater, based on raw data, prior to adding in any correction for tool tolerance.
26. Sable must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool, in accordance with API Standard 1163 Second Edition and includes that tolerance in determining the size of each indication reported to Sable.
27. Sable must account for ILI tool tolerance and anomaly growth rates in scheduled response times, repairs, and future reassessment intervals. Sable must

⁵ Sable may petition the OSFM to revise the reassessment interval for Crack Detection Tool(s) when sufficient evidence is available to determine if crack growth rates could support a longer reassessment interval. Changes to the reassessment interval are subject to OSFM and PHMSA approval.

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document and justify the values used. Sable must demonstrate ILI tool tolerance accuracy for each ILI tool run by using calibration, excavations, and unity plots⁶ that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). Sable must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently over-calling or under-calling, the remaining ILI features must be re-graded accordingly.

28. Prior to the ILI final report being received, Sable must perform at least four (4) separate validation digs that do not interact with each other. At a minimum, Sable must perform validation digs in accordance with Level 2 of API Standard 1163, "In-line Inspection System Qualification" (Second Edition, April 2013).

Discovery of Condition

29. The discovery date must be within 180 days of any ILI tool run for each type of ILI tool.

Immediate Repair Conditions⁷

30. A crack or crack-like anomaly that meets any of the following criteria:
 - a. Crack or crack-like anomaly that is equal to or greater than 50% of pipe wall thickness.
 - b. Crack or crack-like anomaly that has predicted failure pressure of less than 1.39 times the MOP as calculated using crack-like flaw evaluation method ASME FFS-1/API 579-1.
31. Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.39 times the MOP.
32. Any external cluster corrosion or external general corrosion that is located on the bottom half of the pipeline (below the 3 and 9 o'clock positions) where the

⁶ A minimum of four (4) independent direct examination excavations must be used for unity plots.

⁷ The criteria outlined in the state waiver is supplemental to the requirements set forth in §195.452(h)(4)(i) *Immediate repair conditions* and does not relieve Sable from complying with §195.452(h)(4)(i). All immediate repair conditions must be remediated with a permanent repair method.

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remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.⁸

180-Day Repair Conditions⁹

33. A crack or crack-like anomaly that has predicted failure pressure of less than 1.5 times the MOP.
34. Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.
35. All internal or external metal loss anomalies that have an ILI reported depth of 40% or greater wall loss, including tool sizing tolerance for depth.¹⁰
36. For any crack (likely crack or possible crack) or crack-like anomaly, regardless of its dimensions, that interacts with metal loss anomalies and are within one (1) inch (circumferentially) of the longitudinal seam weld, Sable must integrate the ILI results from the most recent crack tool run and the most recent metal loss tool run before the discovery date deadline.

Corrosion Growth Rate Analysis (CGRA)

37. Sable must develop a CGRA procedure to annually calculate corrosion growth rates between successive ILI's (using most recent ILI compared to prior ILI) and perform pipeline remediations needed to assure the integrity of the pipeline is maintained.¹¹ The timing of pipeline remediations under this condition shall be based on the most recent calculation of short-term corrosion rates.
38. The CGRA procedure must include ILI data matching methods¹² to analyze data from successive ILI's, methodologies for growth rate calculations and errors from comparing ILI data.

⁸ Cluster means two or more adjacent metal loss features in the wall of the pipe or weld that may interact based on interaction criteria. General corrosion means uniform or gradually varying loss of wall thickness over an area.

⁹ The criteria outlined in the state waiver is supplemental to the requirements set forth in §195.452(h)(4)(iii) *180-day conditions* and does not relieve Sable from complying with §195.452(h)(4)(iii). All 180-day repair conditions must be remediated with a permanent repair method.

¹⁰ For example, if the ILI tool reports a 31% metal loss anomaly and the tool sizing tolerance is ± 10 for depth, then this anomaly is a 180-day repair condition since it can be considered as an external metal loss anomaly with 41% metal loss depth. If Sable is unable to remediate such indications within 180 days of discovery, Sable must notify the OSFM, temporarily reduce the operating pressure, and take further remedial action in accordance with 49 C.F.R. §195.452 until the indication is remediated or until otherwise authorized by OSFM.

¹¹ At a minimum, Sable must include signal matching between ILI data sets.

¹² If there are several matching techniques that can be used, Sable must utilize the most accurate method of comparing ILI data sets.

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39. Sable must identify the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss.
40. When determining the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss, Sable must account for reported ILI depth, tool tolerance and corrosion growth rates¹³.
41. All metal loss indications that are projected to reach a depth of 70% or greater wall loss prior to the next ILI, will become actionable and must be remediated before the next ILI.

Pressure Reduction

42. If Sable is unable to perform field evaluation and remediation of any required conditions within the time limit conditions specified in the state waiver, Sable must temporarily implement a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two (2) months prior to the date of inspection, until the anomaly is repaired.

In Field Direct Examination of Pipe

43. Direct examinations¹⁴ of pipe must include appropriate non-destructive examination methods for cracking such as magnetic particle inspection (MPI), shear wave technology or phased array ultrasonic testing (PAUT).¹⁵ PAUT must be used for sizing any crack or crack-like anomaly lengths and depths.
44. Permanent repairs of metal loss anomalies are required for any section of pipe with wall loss equal to or greater than 40% in accordance with repair method 1, 4b, or 5 of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition. However, the following additional conditions are applied if Sable chooses repair method 5 for metal loss anomalies:
 - a. Method 5 must not be used on metal loss anomalies that are in the HAZ, girth weld, or longitudinal seam weld.

¹³ Growth projections must use corrosion rates determined in accordance with the CGRA procedure. A default corrosion rate of 32 mpy must be used in determining projections, if corrosion rates determined by CGRA are less than the default value.

¹⁴ Any time the pipeline is exposed for direct examination of an indication or to perform a repair, Sable must document the condition of the coating and carrier pipe (including anomalies) with photographs.

¹⁵ Direct examinations for ILI reported crack or crack-like indications must include a magnetic particle inspection complimented by shear wave technology or inspection by phased array ultrasonic testing.

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- b. Sable must increase the metal loss anomaly's depth by 20% when they input it into the formula for calculating the number of wraps needed for repair method 5.
 - c. After the anomaly is repaired via repair method 5, Sable must monitor the anomaly's wall loss depth in subsequent UTWM tool runs. If the anomaly's wall loss depth increases by more than 15% of the wall thickness in the subsequent UTWM tool runs, Sable must repair this anomaly via repair method 1 or 4b of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition.
45. Permanent repairs are required for all cracks and/or crack-like anomalies discovered during direct examination, regardless of crack depth or crack length in accordance with repair method 1 or 4b of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition.
46. Sable must develop a coating repair procedure for excavated or remediated corrosion anomalies that prevents further external corrosion and seals transition areas from currently insulated pipe to newly coated sections. Any time a shrink sleeve or coating is exposed, remove the shrink sleeve and coating, investigate circumferentially and longitudinally along the pipe for external corrosion and coating deterioration, and recoat with two-part epoxy. Sable must recoat in accordance with their coating repair procedure.¹⁶
47. All external polyurethane foam and the polyethylene tape wrap on buried pipe that are exposed during the field evaluation must not be replaced with new insulation or polyethylene tape wrap.

Integrity Management

48. A fracture mechanics and pressure cycling evaluation is required for un-remediated cracks and crack-like indications detected by ILI or indirect inspection tools.
- a. Sable must determine the predicted failure pressure, failure stress pressure and crack growth of un-remediated cracks and crack-like anomalies in accordance with 49 C.F.R. §192.712(d)(1).
 - b. Sable must perform a fatigue analysis using an applicable fatigue crack growth law or other technically appropriate engineering methodology in accordance with 49 C.F.R. §192.712(d)(2).
49. Sable must analyze a sample of additional indications of varying amounts of metal loss between 10% and 40% for validation. The sample size shall be at least ten (10), unless fewer than ten (10) indications are reported within that range, in which case Sable would examine the number of indications called.
50. When sizing metal loss indications, apply interaction/clustering criteria of 6t by 6t for applicable ILI tool(s).

¹⁶ The coating procedure must be submitted to the OSFM prior to the prior to the effective date of the state waiver.

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51. Sable must send all field measurements to the ILI tool vendor within 90 days of completing direct examinations and require the ILI vendor to validate the accuracy of the tool. Sable must conduct annual meetings with the ILI tool vendor to discuss tool performance and incorporate lessons learned.
52. Sable must utilize a third-party expert to review all ILI reports, verification of digs, data integration, ILI tool tolerances, development of unity plots, measured field findings, failure pressure ratios and any other finding that could affect the integrity of the pipeline. The review must be conducted within six (6) months of each ILI assessment. The third-party expert must be approved by the OSFM prior to being selected.
53. Within one (1) year from date of issuance, Sable must use a NACE-certified expert to conduct an evaluation and determine if alternating current (AC) interference or direct current (DC) interference or shorting that could contribute to external corrosion is occurring. The expert must recommend the frequency of subsequent interference surveys. All evaluations must be approved and signed by the NACE-certified expert.

Data Requirements for Predicted Failure Analysis

54. Unless the defect dimensions have been verified using a direct examination measurements, Sable must explicitly analyze uncertainties in reported assessment results including but not limited to tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly, interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance, in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses.
55. The analyses performed in accordance with this state waiver must utilize pipe and material properties of the pipe body and longitudinal weld seam that are documented in *traceable, verifiable, and complete* records.

Recordkeeping

56. Procedures, records of investigations, data, analyses, and other actions made in accordance with the requirements of this state waiver shall be kept for the life of the pipeline and must be submitted to the OSFM, in the manner requested (electronic, hardcopy, or other format) within 30 days.
57. Sable must maintain the following records:
 - a. Technical approach used for the analysis
 - b. All data used and analyzed
 - c. Pipe and longitudinal weld seam properties
 - d. Procedures used to implement state waiver conditions

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- e. Evaluation methodology used
- f. Models used
- g. Direct in situ examination data
- h. All in-line inspection tool assessments information evaluated
- i. Pressure test data and results
- j. All in-the-ditch assessments performed on the pipeline segments
- k. All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operations results
- l. All finite element analysis results
- m. The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting methodology
- n. The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods
- o. Safety factors used for fatigue life and/or predicted failure pressure calculations
- p. Reassessment time interval and safety factors
- q. The date of the review
- r. Confirmation of the results by qualified technical subject matter expert(s)
- s. Approval by responsible Sable management personnel
- t. Records of additional preventive and mitigative (P&M) measures performed
- u. Reports required by this State Waiver.

Reporting

- 58. Any release on the pipeline shall be reported to the OSFM at the earliest practicable moment following discovery but no later than 24 hours from the time of discovery via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Accident Notification*.¹⁷
- 59. An email notification shall be made at least three (3) days prior to the pipeline being exposed for non-emergency purposes of field evaluation and repair via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Pipeline Repair CA-324*. The email notification shall include, if applicable:
 - a. Tool type and run date
 - b. Unique identifier (e.g. Dig Number, Joint Number, Flaw ID, Condition Type)
 - c. Dig sheets
 - d. Field contact information for Sable
 - e. Time and location of the field evaluation and repair.
- 60. Sable shall provide a Summary of Conditions Report within 210 days of the last date of an ILI run via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Summary of Conditions CA-324* and include:

¹⁷ This requirement does not relieve Sable from spill reporting requirements that might exist under local, state or federal regulations.

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- a. Tool type
 - b. Run date
 - c. Summary of Conditions Report¹⁸
 - d. Final Vendor Report and Pipe Tally
61. Sable shall provide a report to the OSFM by June 15th of every year for the duration of the state waiver. The report shall be addressed to the OSFM Assistant Deputy Director, Chief of Pipeline Safety via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Annual Report CA-324*. At a minimum, the annual report shall contain the following, if applicable:
- a. A Closure Report for the previous calendar (CY) which contains:
 - i. Features that were remediated in previous CY
 1. Provide documentation for the in-the-ditch assessments and repairs
 - ii. Identify features that remain to be assessed
 - iii. Unity Plots for previous ILI runs
 - b. Fracture mechanics and pressure cycling analyses in accordance with Condition 48
 - c. The third-party ILI expert reviews in accordance with Condition 52
 - d. AC and DC Interference surveys that are due in accordance with Condition 53
 - e. A copy of the CGRA for prior year including:
 - i. Mean corrosion growth rate for the pipeline
 - ii. Distribution graph of the corrosion growth rate for the pipeline (e.g. occurrences (#) vs. corrosion rate (mpy))

Limitations

62. This state waiver is limited to a term of no more than (10) years from the date of issuance. If Sable elects to seek renewal of this state waiver, it must submit a renewal request to the OSFM at least 180 days prior to the expiration date, including a justification for continuation of the waiver.
63. Should Sable fail to comply with any conditions of this state waiver or should the OSFM determine that this state waiver is no longer appropriate or is inconsistent with pipeline safety, the OSFM may revoke the state waiver and require Sable to comply with all appropriate regulatory requirements.
64. The OSFM may order the pipeline shutdown at any time.
65. The OSFM may issue a compliance order or may initiate proceedings to determine the nature and extent of the violations and appropriate civil penalty for

¹⁸ The OSFM may stipulate specific formatting or other information (e.g. Condition Type, Anomaly Details, Remaining Strength Calculation Method, Failure Pressure, CGRA, etc.) to be included in the Summary of Conditions Reports, Closure Report and Annual Reports if information provided is not deemed sufficient.

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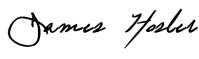
failure to comply with this state waiver. The terms and conditions of any compliance order shall take precedence over the terms of the state waiver.

66. In the event of conflict between the state waiver conditions and industry standards, the state waiver conditions shall prevail.

67. If Sable sells, merges, transfers or otherwise disposes of all or part of the assets covered by the state waiver, Sable must provide the OSFM written notice of the change within 30 days of the consummation date. In the event of such transfer, the OSFM reserves the right to revoke, suspend, or modify the state waiver.

Should you have any questions, please contact Alin Podoreanu, Supervising Pipeline Safety Engineer at (916) 212-8891.

Sincerely,

DocuSigned by:

980F8D3AE95C42E...

JAMES HOSLER
Assistant Deputy Director
Chief of Pipeline Safety and CUPA Programs

Enclosure(s): (1) Pacific Pipeline Company State Waiver Application for CA-324

cc: Doug Allen, Supervising Pipeline Safety Engineer, OSFM
Andy Chau, Supervising Pipeline Safety Engineer, OSFM
Brendan Feery, Supervising Pipeline Safety Engineer, OSFM
Huy Nguyen, Supervising Pipeline Safety Engineer, OSFM
Alin Podoreanu, Supervising Pipeline Safety Engineer, OSFM
Tuan Tran, Pipeline Safety Engineer, OSFM
Josh Cleaver, Staff Counsel, CAL FIRE
Max Kieba, Engineering and Research Division, PHMSA
Joshua Johnson, Engineering and Research Division, PHMSA

EXHIBIT F



DEPARTMENT OF FORESTRY AND FIRE PROTECTION
OFFICE OF THE STATE FIRE MARSHAL
P.O. Box 944246
Sacramento, California 94244-2460
(916) 568-3800
Website: www.fire.ca.gov



CERTIFIED MAIL No: 9589-0710-5270-1475-5353-15

December 17, 2024

Lance Yearwood
Vice President
Sable Offshore Corp
845 Texas Avenue, Suite 2920
Houston, Texas 77002

SUBJECT: LETTER OF DECISION ON THE STATE WAIVER REQUEST FOR LIMITED EFFECTIVENESS OF CATHODIC PROTECTION ON THERMALLY INSULATED PIPELINE AND CORROSION OF OR ALONG A LONGITUDINAL SEAM WELD (CA-325A/B)

Operator: Sable Offshore Corp
OPID# 40851
845 Texas Avenue, Suite 2920
Houston, Texas 77002

Pipeline: OSFM Line ID 0001 - 113.56 miles (Gaviota to Sisquoc to Pentland) of Sable Offshore Corp CA-325A/B (OSFM Line ID 0001) located in Santa Barbara County, San Luis Obispo County, and Kern County, California as described in the request of state waiver dated April 24, 2024

Dear Mr. Yearwood:

The Office of the State Fire Marshal (OSFM) received Sable Offshore Corp's (*Sable*) state waiver request (*Application*) on April 24, 2024, in accordance with the terms of the Consent Decree (CD) between Plains Pipeline, L.P. and the United States of America and the People of the State of California, DOJ Case REF. NO. 90-5-1-1-1130 (Appendix B, Article 1.1.D).

In addition, Sable requested a regulatory relief from Title 49 Code of Federal Regulations (49 C.F.R.), § 195.452(h)(4)(iii)(H) *Corrosion of or along a longitudinal seam weld* for Sable CA-325 A/B.

Sable explained that its goal is to appropriately manage the risk of corrosion under insulation that may occur as a result of inadequate cathodic protection due to the

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shielding effects of the polyurethane foam and the polyethylene tape wrap. Sable described the measures it has taken to address this risk and implemented and proposed a number of additional measures designed to mitigate the risk of corrosion under insulation that may result from potential ineffective cathodic protection (CP).

Sable provided the OSFM with its proposed measures to mitigate the risk of corrosion under insulation. Sable also provided the OSFM information from the completed in-line inspections and additional data requested by our office. The OSFM Pipeline Safety Engineers have reviewed the materials provided and have been in communication with the United States Department of Transportation (USDOT), Pipeline and Hazardous Materials Safety Administration (PHMSA) Engineering and Research Division to incorporate PHMSA's recommended conditions into the state waiver.

The OSFM has regulatory jurisdiction over the safety standards and practices of intrastate hazardous liquid pipeline transportation within California. As a Pipeline Safety Program that is certified under 49 USC § 60105, the OSFM may grant a state waiver with a pipeline safety regulation adopted by the state of California. Title 49 C.F.R., Part 195 was adopted by reference as it relates to hazardous liquid pipelines within Title 19 California Code of Regulations (19 CCR), Section 2000.

This state waiver applies to Sable's Line CA-325A/B (OSFM Line ID 0001) which consists of a 113.56 mile long, 30-inch outside diameter pipeline segment with the origin and termination points as described in the application. The pipeline is located in Santa Barbara County, San Luis Obispo County, and Kern County, California and shall be referred herein as CA-325A/B. CA-325A/B consists of two shorter pipeline segments, CA-325A and CA-325B. The pipeline segment CA-325A, located completely in Santa Barbara County, starts in Gaviota and ends at Sisquoc. CA-325A is approximately 38.72 miles long. The other pipeline segment, CA-325B, which is directly downstream of CA-325A, begins at Sisquoc and terminates in Pentland. CA-325B is approximately 74.84 miles long and traverses Santa Barbara County, San Luis Obispo County, and Kern County, California. The state waiver shall not become effective until (1) PHMSA issues an Order approving the waiver or stating it has no objection to the waiver or (2) PHMSA takes no action on the waiver within sixty (60) days after receiving the Letter of Decision from the OSFM.

The state waiver is limited to a term of no more than ten (10) years from the date it becomes effective, which shall be considered as the date of issuance. The OSFM may terminate the state waiver under conditions detailed below.

Applicable Regulations

The OSFM hereby grants this state waiver for CA-325 A/B, provided that Sable complies with the specific requirements in this state waiver and any additional conditions outlined by PHMSA. The pipeline must be operated and maintained in accordance with the CD, these

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state waiver conditions and 49 C.F.R. Part 195, with the exception of 49 C.F.R. §195.452(h)(4)(iii)(H). In event of a conflict between the state waiver conditions and the applicable requirements under 49 C.F.R. Part 195, the state waiver conditions control. Should additional federal or State statutory or regulatory requirements come into effect following the implementation of this state waiver, CA-325 A/B shall be subject to those requirements except where they are in conflict with the State Waiver or the safe operation of the pipeline.

General Conditions

1. The pipeline can only be used to transport crude oil as stated in the application.
2. The maximum operating pressure (MOP) cannot exceed:
 - a. 1000 pounds per square inch gauge (psig) for CA-325A.
 - b. 1292 psig for CA-325B.
3. The maximum operating temperature of the crude oil must not exceed:
 - a. 125 Fahrenheit for more than 12 consecutive hours for CA-325A.
Temperature transmitters must be installed on CA-325A at Gaviota station to monitor the temperature of CA-325A/B at this facility.
 - b. 110 Fahrenheit for more than 12 consecutive hours for CA-325B.
Temperature transmitters must be installed on CA-325A/B at Sisquoc station to monitor the temperature of CA-325A/B at this facility.
4. Prior to startup, Sable must develop and implement procedures for the conditions and requirements described in the state waiver.
5. This state waiver does not relieve Sable from other requirements under 49 C.F.R. Part 195 or the Elder California Pipeline Safety Act of 1981 other than contained herein.
6. This state waiver does not relieve Sable from any requirements imposed by the Consent Decree (United States District Court Central District of California Civil Action No. 2:20-cv-02415).
7. In-line inspection must include:
 - a. Use of a tool that is at least capable of reliably detecting and identifying cluster corrosion and general corrosion. Definition of cluster and general corrosion is as follows:
 - i. Cluster means two or more adjacent metal loss features in the wall of the pipe or weld that may interact based on interaction criteria.
 - ii. General corrosion means uniform or gradually varying loss of wall thickness over an area.
 - b. Use of a tool that is at least capable of reliably detecting and sizing corrosion at a 90 percent probability of detection (POD) and probability of identification (POI)
 - c. Use of a tool that is at least capable of reliably detecting and sizing crack or crack-like anomalies at a 90 percent POD and POI

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8. Prior to placing CA-325A/B in operation, Sable must perform fracture toughness tests on the existing 30" pipe from CA-325A/B in accordance with ASTM E1820-23B Standard Test Method for Measurement of Fracture Toughness. All of the test specimens must be from both of the two following predominant existing 30" pipe specifications:
 - a. API 5L X70 pipe with a nominal thickness of 0.281" that was manufactured by the various pipe mills in the 1980s.
 - b. API 5L X65 pipe with a nominal thickness of 0.344" that was manufactured by the various pipe mills in the 1980s.At least three (3) separate tests must be performed from each pipe mill, for both of the two pipe specifications listed above, to obtain the fracture toughness values of the pipe body, heat affected zone (HAZ)¹, and the DSAW long seam weld on the pipe to represent the fracture toughness of CA-325A/B (i.e. three (3) samples for pipe body, three (3) samples for HAZ, and three (3) samples for the DSAW long seam weld). The lowest fracture toughness value must be applied to conditions 10, 31, 34, and 49. Sable may use pipe samples taken opportunistically during ongoing pipeline maintenance and repair efforts.²
9. All immediate and 180-day repair conditions that are listed in this state waiver must be evaluated and remediated prior to restarting CA-325A/B. Sable must utilize Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) tools within seven (7) days of achieving initial steady state operation in accordance with an ILI survey schedule approved by the OSFM. Sable must utilize the most recent Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) results when identifying these repair conditions.
10. Remaining strength of pipe calculation for all metal loss anomalies must be in accordance with the Modified B31G method as described in ASME B31G *Manual for Determining the Remaining Strength of Corroded Pipelines*. If ASME B31G 2012 Edition is used, then it must comply with the conditions in accordance with Section 1.2 and exclusions in accordance with Section 1.3 of ASME B31G 2012 Edition. However, if the metal loss anomaly intersects or is within one (1) inch (circumferentially) of the longitudinal seam weld, Sable must also calculate the predicted failure pressure of the anomaly by using the crack-like flaw evaluation method ASME FFS-1/API 579-1.
11. Sable must utilize cleaning pigs at regular intervals not to exceed a biweekly basis to maintain adequate cleanliness on the internal pipe wall of its CA-325A/B.

¹ The heat affected zone (HAZ), as used in the state waiver, is defined as a 1-inch-wide area on either side of the longitudinal weld seam.

² Sable must submit all fracture toughness results to the OSFM prior to restarting the pipeline.

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Pressure Testing

12. Prior to placing the pipeline in operation, Sable must conduct a spike hydrostatic pressure test of the state waiver pipeline segment CA-325A at a minimum pressure that is at least 1.39 times the MOP, for a minimum of 15 minutes after the spike test pressure is stabilized. Sable must ensure that the spike hydrostatic pressure at the highest elevation of each testable segment is at least 1.39 times the MOP. Sable must field evaluate and remediate the following anomalies before performing the spike hydrostatic test on CA-325A:
 - a. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.
 - b. All anomalies that have a predicted failure pressure less than or equal to 1.5 times MOP.
13. Immediately following the spike hydrostatic pressure test, Sable must conduct an 8-hour hydrostatic pressure test of the state waiver pipeline segment CA-325A at a minimum of 1.25 times the MOP.
14. Prior to placing the pipeline in operation, Sable must conduct a hydrostatic pressure test of the state waiver pipeline segment CA-325B at a minimum pressure of 1.25 times the MOP, for a minimum of 8 hours. Sable must ensure that the hydrostatic pressure at the highest elevation of each testable segment is at least 1.25 times the MOP. Sable must field evaluate and remediate the following anomalies before performing the hydrostatic test on CA-325B:
 - a. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.
 - b. All anomalies that have a predicted failure pressure less than or equal to 1.4 times MOP.
15. Sable must obtain the Test ID from the OSFM for each hydrostatic pressure test segment and have the approved independent testing firm forward the certified test results to the OSFM.
16. Each hydrostatic pressure test must be performed in accordance with the applicable requirements of 49 C.F.R., Part 195 E – Pressure Testing and monitored by an independent testing firm listed under the OSFM approved hydrostatic testing companies.
17. Failures resulting from the spike hydrostatic pressure test or the 8-hour strength test shall be immediately reported³ to the OSFM via email at PipelineNotification@fire.ca.gov
Subject: OSFM State Waiver - Hydrotest Failure.
18. Section(s) of the state waiver pipeline segments that failed during the required hydrotesting must be repaired by removing and replacing the failed section. The OSFM reserves the right to revoke the state waiver if failure(s) raise the concern that the pipeline cannot be safely operated.

³ In addition to the OSFM reporting, Sable shall follow all additional state reporting requirements.

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In-Line Inspection (ILI) Assessment and Frequency

19. At least 90 days prior to performing in-line inspections of the state waiver segment, Sable shall provide the OSFM with a written notification to PipelineNotification@fire.ca.gov describing its assessment plan with the following information:
 - a) Dates for integrity assessment
 - b) In-line inspection tool(s) selected, in accordance with API Standard 1163 Section 5 and NACE SP0102⁴ to assess the integrity of the subject pipe segment(s) in which ILIs must be capable to detect and size wall loss, dents, internal corrosion, external corrosion, cracks and crack-like indications
 - c) In-line inspection tool vendor(s)
 - d) Required tool specifications including operational specifications and anomaly sizing tolerances
 - e) Tool validation methodology
 - f) Anomaly feature identification criteria and reporting thresholds – wall loss, dents, internal corrosion, external corrosion, cracks, and crack-like indications
 - g) Criteria used to identify locations for excavation and field verification
 - h) Non-destructive examination
20. Within seven (7) days prior to any anticipated ILI tool run, Sable must utilize extensive brush pigs and solvents (xylene or other chemicals) to ensure that the internal pipe wall does not have any corrosive products, wax, and bacteria buildup that may affect the ILI tool performance.
21. Metal Loss Tool(s)
 - a. Initial ILI tool runs – Each year, during the first two (2) years of operating CA-325 A/B, Sable shall conduct at least two (2) ILIs using a UTWM tool with an inertial measurement unit (IMU). Sable shall compare both runs and evaluate all available information, including these tool runs and corresponding IMU data. Sable shall perform the UTWM tool run every six (6) months not to exceed nine (9) months. If a UTWM tool run is unsuccessful, Sable shall identify the limitations that prevented the UTWM tool run from being successful, consider changes to increase the likelihood of a successful UTWM tool run, and use best efforts to rerun the UTWM tool within 30 days.
 - b. Subsequent ILI tool runs – After the first two (2) years of operating CA-325 A/B, Sable shall conduct at least one (1) Ultrasonic Wall Measurement tool (UTWM) each calendar year, not to exceed 15 months or the ILI assessment must be assessed at more frequent intervals if the remaining Failure Pressure Ratio will be less than 1.39 times MOP prior to the next ILI assessment, based upon anomaly growth estimates and pressure cycling. If,

⁴ Industry standards that are referenced in this state waiver must utilize the editions that are incorporated by referenced in Title 49 Part 195.3 unless another edition was explicitly specified.

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- any UTWM tool run is deemed to be unsuccessful, Sable shall document the reasons why the UTWM tool was unsuccessful, consider changes to increase the likelihood of a successful UTWM tool run, and must reassess the pipeline within 30 days after it was deemed to be unsuccessful. All metal loss tool runs must also utilize an Inertial Measurement Unit (IMU).
22. Crack Detection Tools - Sable must run at least one (1) Ultrasonic Shear Wave Crack Detection (USCD) tool each calendar year, not to exceed 15 months⁵ or the ILI assessment must be assessed at more frequent intervals if Condition 49 determined a shorter assessment interval.
- a. These crack tool runs must utilize an Inertial Measurement Unit (IMU) and must be able to detect and size axial and circumferential cracks.
 - b. USCD Performance Specification Requirements
 - i. The USCD tools must have a probability of detection that is $\geq 90\%$ for axial and circumferential cracks.
 - ii. The minimum crack depth that can be detected must be at least 1 mm for axial and circumferential cracks that are located in the base material.
 - iii. The minimum crack depth that can be detected must be at least 2 mm for axial and circumferential cracks that are located in the weld.
 - iv. The depth sizing accuracy for cracks must be ± 0.8 mm for axial cracks and ± 1 mm for circumferential cracks.
23. Dents and Pipe Deformation: Sable shall conduct a high-resolution deformation ILI tool with each UTWM.
24. Where any ILI tool fails to record data for 5% or more of the external and/or internal surface area of the inspected segment, reassess with the ILI tool to cover the area that is deemed to be inadequate data of the inspected segment. In addition, if the ILI tool travels at a speed that is outside the range of the tool velocity listed in the tool specification for 2% or more of the length of the inspected segment, Sable must rerun the ILI tool to reassess the pipeline segment in which the ILI tool velocity was outside of the specified tool velocity range.
25. All ILI tool runs must obtain the Test ID from the OSFM prior to run.
26. Sable must require its ILI tool vendor(s) to include in the vendor's inspection report all metal loss indications of 10% or greater, based on raw data, prior to adding in any correction for tool tolerance.
27. Sable must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool, in accordance with API Standard 1163 Second Edition and includes that tolerance in determining the size of each indication reported to Sable.

⁵ Sable may petition the OSFM to revise the reassessment interval for Crack Detection Tool(s) when sufficient evidence is available to determine if crack growth rates could support a longer reassessment interval. Changes to the reassessment interval are subject to the OSFM and PHMSA approval.

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28. Sable must account for ILI tool tolerance and anomaly growth rates in scheduled response times, repairs, and future reassessment intervals. Sable must document and justify the values used. Sable must demonstrate ILI tool tolerance accuracy for each ILI tool run by using calibration, excavations, and unity plots⁶ that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). Sable must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently over-calling or under-calling, the remaining ILI features must be re-graded accordingly.
29. Prior to the ILI final report being received, Sable must perform at least four (4) separate validation digs that do not interact with each other. At a minimum, Sable must perform validation digs in accordance with Level 2 of API Standard 1163, "In-line Inspection System Qualification" (Second Edition, April 2013).

Discovery of Condition

30. The discovery date must be within 180 days of any ILI tool run for each type of ILI tool.

Immediate Repair Conditions⁷

31. A crack or crack-like anomaly that meets any of the following criteria:
 - a. Crack or crack-like anomaly that is equal to or greater than 50% of pipe wall thickness.
 - b. Crack or crack-like anomaly that has predicted failure pressure of less than 1.39 times the MOP as calculated using crack-like flaw evaluation method ASME FFS-1/API 579-1.
32. Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.39 times the MOP.
33. Any external cluster corrosion or external general corrosion that is located on the bottom half of the pipeline (below the 3 and 9 o'clock positions) where the remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.⁸

⁶ A minimum of four (4) independent direct examination excavations must be used for unity plots.

⁷ The criteria outlined in the state waiver is supplemental to the requirements set forth in §195.452(h)(4)(i) *Immediate repair conditions* and does not relieve Sable from complying with §195.452(h)(4)(i). All immediate repair conditions must be remediated with a permanent repair method.

⁸ Cluster means two or more adjacent metal loss features in the wall of the pipe or weld that may interact based on interaction criteria. General corrosion means uniform or gradually varying loss of wall thickness over an area.

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180-Day Repair Conditions⁹

34. A crack or crack-like anomaly that has predicted failure pressure of less than 1.5 times the MOP.
35. Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.
36. All internal or external metal loss anomalies that have an ILI reported depth of 40% or greater wall loss, including tool sizing tolerance for depth.¹⁰
37. For any crack (likely crack or possible crack) or crack-like anomaly, regardless of its dimensions, that interacts with metal loss anomalies and are within one (1) inch (circumferentially) of the longitudinal seam weld, Sable must integrate the ILI results from the most recent crack tool run and the most recent metal loss tool run before the discovery date deadline.

Corrosion Growth Rate Analysis (CGRA)

38. Sable must develop a CGRA procedure to annually calculate corrosion growth rates between successive ILI's (using most recent ILI compared to prior ILI) and perform pipeline remediations needed to assure the integrity of the pipeline is maintained.¹¹ The timing of pipeline remediations under this condition shall be based on the most recent calculation of short-term corrosion rates.
39. The CGRA procedure must include ILI data matching methods¹² to analyze data from successive ILI's, methodologies for growth rate calculations and errors from comparing ILI data.
40. Sable must identify the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss.
41. When determining the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss, Sable must account for reported ILI depth, tool tolerance and corrosion growth rates¹³.

⁹ The criteria outlined in the state waiver is supplemental to the requirements set forth in §195.452(h)(4)(iii) *180-day conditions* and does not relieve Sable from complying with §195.452(h)(4)(iii). All 180-day repair conditions must be remediated with a permanent repair method.

¹⁰ For example, if the ILI tool reports a 31% metal loss anomaly and the tool sizing tolerance is ± 10 for depth, then this anomaly is a 180-day repair condition since it can be considered as an external metal loss anomaly with 41% metal loss depth. If Sable is unable to remediate such indications within 180 days of discovery, Sable must notify OSFM, temporarily reduce the operating pressure, and take further remedial action in accordance with 49 C.F.R. §195.452 until the indication is remediated or until otherwise authorized by the OSFM.

¹¹ At a minimum, Sable must include signal matching between ILI data sets.

¹² If there are several matching techniques that can be used, Sable must utilize the most accurate method of comparing ILI data sets.

¹³ Growth projections must use corrosion rates determined in accordance with the CGRA procedure. A default corrosion rate of 32 mpy must be used in determining projections, if corrosion rates determined by CGRA are less than the default value.

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42. All metal loss indications that are projected to reach a depth of 70% or greater wall loss prior to the next ILI, will become actionable and must be remediated before the next ILI.

Pressure Reduction

43. If Sable is unable to perform field evaluation and remediation of any required conditions within the time limit conditions specified in the state waiver, Sable must temporarily implement a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two (2) months prior to the date of inspection, until the anomaly is repaired.

In Field Direct Examination of Pipe

44. Direct examinations¹⁴ of pipe must include appropriate non-destructive examination methods for cracking such as magnetic particle inspection (MPI), shear wave technology or phased array ultrasonic testing (PAUT).¹⁵ PAUT must be used for sizing any crack or crack-like anomaly lengths and depths.
45. Permanent repairs of metal loss anomalies are required for any section of pipe with wall loss equal to or greater than 40% in accordance with repair method 1, 4b, or 5 of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition. However, the following additional conditions are applied if Sable chooses repair method 5 for metal loss anomalies:
- a. Method 5 must not be used on metal loss anomalies that are in the HAZ, girth weld, or longitudinal seam weld.
 - b. Sable must increase the metal loss anomaly's depth by 20% when they input it into the formula for calculating the number of wraps needed for repair method 5.
 - c. After the anomaly is repaired via repair method 5, Sable must monitor the anomaly's wall loss depth in subsequent UTWM tool runs. If the anomaly's wall loss depth increases by more than 15% of the wall thickness in the subsequent UTWM tool runs, Sable must repair this anomaly via repair method 1 or 4b of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition.
46. Permanent repairs are required for all cracks and/or crack-like anomalies discovered during direct examination, regardless of crack depth or crack length in accordance with repair method 1 or 4b of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition.

¹⁴ Any time the pipeline is exposed for direct examination of an indication or to perform a repair, Sable must document the condition of the coating and carrier pipe (including anomalies) with photographs.

¹⁵ Direct examinations for ILI reported crack or crack-like indications must include a magnetic particle inspection complimented by shear wave technology or inspection by phased array ultrasonic testing.

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47. Sable must develop a coating repair procedure for excavated or remediated corrosion anomalies that prevents further external corrosion and seals transition areas from currently insulated pipe to newly coated sections. Any time a shrink sleeve or coating is exposed, remove the shrink sleeve and coating, investigate circumferentially and longitudinally along the pipe for external corrosion and coating deterioration, and recoat with two-part epoxy. Sable must recoat in accordance with their coating repair procedure.¹⁶
48. All external polyurethane foam and the polyethylene tape wrap on buried pipe that are exposed during the field evaluation must not be replaced with new insulation or polyethylene tape wrap.

Integrity Management

49. A fracture mechanics and pressure cycling evaluation is required for un-remediated cracks and crack-like indications detected by ILI or indirect inspection tools.
 - a. Sable must determine the predicted failure pressure, failure stress pressure and crack growth of un-remediated cracks and crack-like anomalies in accordance with 49 C.F.R. §192.712(d)(1).
 - b. Sable must perform a fatigue analysis using an applicable fatigue crack growth law or other technically appropriate engineering methodology in accordance with 49 C.F.R. §192.712(d)(2).
50. Sable must analyze a sample of additional indications of varying amounts of metal loss between 10% and 40% for validation. The sample size shall be at least ten (10), unless fewer than ten (10) indications are reported within that range, in which case Sable would examine the number of indications called.
51. When sizing metal loss indications, apply interaction/clustering criteria of 6t by 6t for applicable ILI tool(s).
52. Sable must send all field measurements to the ILI tool vendor within 90 days of completing direct examinations and require the ILI vendor to validate the accuracy of the tool. Sable must conduct annual meetings with the ILI tool vendor to discuss tool performance and incorporate lessons learned.
53. Sable must utilize a third-party expert to review all ILI reports, verification of digs, data integration, ILI tool tolerances, development of unity plots, measured field findings, failure pressure ratios and any other finding that could affect the integrity of the pipeline. The review must be conducted within six (6) months of each ILI assessment. The third-party expert must be approved by the OSFM prior to being selected.
54. Within one (1) year from date of issuance, Sable must use a NACE-certified expert to conduct an evaluation and determine if alternating current (AC)

¹⁶ The coating procedure must be submitted to the OSFM prior to the prior to the effective date of the state waiver.

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interference or direct current (DC) interference or shorting that could contribute to external corrosion is occurring. The expert must recommend the frequency of subsequent interference surveys. All evaluations must be approved and signed by the NACE-certified expert.

Data Requirements for Predicted Failure Analysis

55. Unless the defect dimensions have been verified using a direct examination measurements, Sable must explicitly analyze uncertainties in reported assessment results including but not limited to tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly, interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance, in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses.
56. The analyses performed in accordance with this state waiver must utilize pipe and material properties of the pipe body and longitudinal weld seam that are documented in *traceable, verifiable, and complete* records.

Recordkeeping

57. Procedures, records of investigations, data, analyses, and other actions made in accordance with the requirements of this state waiver shall be kept for the life of the pipeline and must be submitted to the OSFM, in the manner requested (electronic, hardcopy, or other format) within 30 days.
58. Sable must maintain the following records:
 - a. Technical approach used for the analysis
 - b. All data used and analyzed
 - c. Pipe and longitudinal weld seam properties
 - d. Procedures used to implement state waiver conditions
 - e. Evaluation methodology used
 - f. Models used
 - g. Direct in situ examination data
 - h. All in-line inspection tool assessments information evaluated
 - i. Pressure test data and results
 - j. All in-the-ditch assessments performed on the pipeline segments
 - k. All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operations results
 - l. All finite element analysis results
 - m. The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting methodology

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- n. The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods
- o. Safety factors used for fatigue life and/or predicted failure pressure calculations
- p. Reassessment time interval and safety factors
- q. The date of the review
- r. Confirmation of the results by qualified technical subject matter expert(s)
- s. Approval by responsible Sable management personnel
- t. Records of additional preventive and mitigative (P&M) measures performed
- u. Reports required by this State Waiver.

Reporting

59. Any release on the pipeline shall be reported to the OSFM at the earliest practicable moment following discovery but no later than 24 hours from the time of discovery via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Accident Notification*.¹⁷
60. An email notification shall be made at least three (3) days prior to the pipeline being exposed for non-emergency purposes of field evaluation and repair via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Pipeline Repair CA-325 A/B*. The email notification shall include, if applicable:
- d. Tool type and run date
 - e. Unique identifier (e.g. Dig Number, Joint Number, Flaw ID, Condition Type)
 - f. Dig sheets
 - g. Field contact information for Sable
 - h. Time and location of the field evaluation and repair.
61. Sable shall provide a Summary of Conditions Report within 210 days of the last date of an ILI run via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Summary of Conditions CA-325 A/B* and include:
- i. Tool type
 - j. Run date
 - k. Summary of Conditions Report¹⁸
 - l. Final Vendor Report and Pipe Tally
62. Sable shall provide a report to the OSFM by June 15th of every year for the duration of the state waiver. The report shall be addressed to the OSFM Assistant Deputy Director, Chief of Pipeline Safety via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Annual Report*

¹⁷ This requirement does not relieve Sable from spill reporting requirements that might exist under local, state or federal regulations.

¹⁸ The OSFM may stipulate specific formatting or other information (e.g. Condition Type, Anomaly Details, Remaining Strength Calculation Method, Failure Pressure, CGRA, etc.) to be included in the Summary of Conditions Reports, Closure Report and Annual Reports if information provided is not deemed sufficient.

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CA-325 A/B. At a minimum, the annual report shall contain the following, if applicable:

- a. A Closure Report for the previous calendar (CY) which contains:
 - i. Features that were remediated in previous CY
 1. Provide documentation for the in-the-ditch assessments and repairs
 - ii. Identify features that remain to be assessed
 - iii. Unity Plots for previous ILI runs
- b. Fracture mechanics and pressure cycling analyses in accordance with Condition 49
- c. The third-party ILI expert reviews in accordance with Condition 53
- d. AC and DC Interference surveys that are due in accordance with Condition 54
- e. A copy of the CGRA for prior year including:
 - i. Mean corrosion growth rate for the pipeline
 - ii. Distribution graph of the corrosion growth rate for the pipeline (e.g. occurrences (#) vs. corrosion rate (mpy))

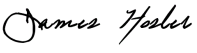
Limitations

63. This state waiver is limited to a term of no more than ten (10) years from the date of issuance. If Sable elects to seek renewal of this state waiver, it must submit a renewal request to the OSFM at least 180 days prior to the expiration date, including a justification for continuation of the waiver.
64. Should Sable fail to comply with any conditions of this state waiver or should the OSFM determine that this state waiver is no longer appropriate or is inconsistent with pipeline safety, the OSFM may revoke the state waiver and require Sable to comply with all appropriate regulatory requirements.
65. The OSFM may order the pipeline shutdown at any time.
66. The OSFM may issue a compliance order or may initiate proceedings to determine the nature and extent of the violations and appropriate civil penalty for failure to comply with this state waiver. The terms and conditions of any compliance order shall take precedence over the terms of the state waiver.
67. In the event of conflict between the state waiver conditions and industry standards, the state waiver conditions shall prevail.
68. If Sable sells, merges, transfers or otherwise disposes of all or part of the assets covered by the state waiver, Sable must provide the OSFM written notice of the change within 30 days of the consummation date. In the event of such transfer, the OSFM reserves the right to revoke, suspend, or modify the state waiver.

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Should you have any questions, please contact Alin Podoreanu, Supervising Pipeline Safety Engineer at (916) 212-8891.

Sincerely,

DocuSigned by:

980F8D3AE95C42E...
JAMES HOSLER
Assistant Deputy Director
Chief of Pipeline a Safety and CUPA Programs

Enclosure(s): (1) Pacific Pipeline Company State Waiver Application for CA-325 A/B

cc: Doug Allen, Supervising Pipeline Safety Engineer, OSFM
Andy Chau, Supervising Pipeline Safety Engineer, OSFM
Brendan Feery, Supervising Pipeline Safety Engineer, OSFM
Huy Nguyen, Supervising Pipeline Safety Engineer, OSFM
Alin Podoreanu, Supervising Pipeline Safety Engineer, OSFM
Tuan Tran, Pipeline Safety Engineer, OSFM
Josh Cleaver, Staff Counsel, CAL FIRE
Max Kieba, Engineering and Research Division, PHMSA
Joshua Johnson, Engineering and Research Division, PHMSA

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PROOF OF SERVICE

I, Josie Cisneros, declare:

I am employed in the County of Los Angeles, State of California. I am over the age of 18 and not a party to the within action. My business address is Alston & Bird LLP, 350 South Grand Avenue, 51st Floor, Los Angeles, CA 90071.

On July 7, 2025, I served the document(s) described as **DECLARATION OF MICHAEL J. ROSENFELD IN SUPPORT OF REAL PARTIES IN INTEREST SABLE OFFSHORE CORP. AND PACIFIC PIPELINE COMPANY'S OPPOSITION TO APPLICATION FOR PRELIMINARY INJUNCTON (VOL. 1 OF 4)** on the interested parties in this action by enclosing the document(s) in a sealed envelope addressed as follows: *See Attached Service List.*

BY ELECTRONIC MAIL TRANSMISSION WITH ATTACHMENT: On this date, I transmitted the above-mentioned document by electronic mail transmission with attachment to the parties at the electronic mail transmission address set forth on the attached service list.

[State] I declare under penalty of perjury under the laws of the State of California that the above is true and correct.

Executed on July 7, 2025, at Los Angeles, California.

/s/Josie Cisneros

1 **SERVICE LIST**

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3 David Pettit, Esq.
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