STATE CAPITOL
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California Legislature

September 27, 2024

Delivered Electronically

Mr. Joe Tyler, Director/Fire Chief
Mr. Daniel Berlant, State Fire Marshal
California Department of Forestry and Fire Protection
P.O. Box 944246
Sacramento, CA 94244-2460

Re: Transparency and Public Engagement in OSFM's Determination of Whether to Restart Pipelines CA-324 and CA-325

Dear Mr. Tyler and Mr. Berlant,

It has come to our attention that the Office of the State Fire Marshal ("OSFM") is considering whether to allow Sable Offshore Corp. ("Sable") to restart the pipeline that caused the 2015 oil spill at Refugio State Beach Park. We write to express our concern regarding the process used by the OSFM to consider approving a project that would invite another coastal oil spill and impact the safety of the Central Coast community.

The restart of this pipeline, now known as CA-324, and related facilities, including three offshore drilling platforms, and the onshore oil processing facility at Las Flores Canyon, is a matter of profound importance to our constituents along the Central Coast. When this pipeline ruptured in 2015, the effect on nearby communities was catastrophic. The spill devastated at least 150 miles of coastline, forced the closure of fisheries and beaches, killed an untold number of marine mammals, cost hundreds of millions of dollars to clean up, negatively impacted local businesses, and caused an estimated 140,000 lost recreational user days between Santa Barbara, Ventura, and Los Angeles Counties. Many of the restoration projects were funded just last year and have just begun work.[1]

[1] California Department of Fish and Wildlife et al., *Refugio Beach Oil Spill Final Damage Assessment and Restoration Plan/Environmental Assessment*, p. 18 (June 2021) [hereinafter "NRDA"], available at: https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=193144&inline.

CA-324 and CA-325 do not have effective protection against corrosion, which is ultimately what caused the 2015 spill.[2] Without protection from corrosion, another spill from these pipelines is incredibly likely. When Santa Barbara County was considering a proposal to replace these pipelines, it estimated the pipelines would result in a spill once a year, and a rupture once every four years.[3] The County also estimated that another spill from these pipelines could be twice the size of the 2015 spill — even if the pipelines are retrofitted with automatic shut-off valves.[4]

In light of the threat to public health and safety that these facilities pose, several community organizations asked OSFM for increased transparency and public engagement as it considers whether to restart CA-324 and CA-325. In response, OSFM agreed to "[h]old public meetings and engage with the public at appropriate milestones for a potential restart."[5]

OSFM has approved a Risk Analysis, which Sable is now implementing. OSFM is also currently reviewing Sable's application for a state waiver to allow this pipeline to operate without meeting Federal standards or fixing the flaws that caused it to rupture almost 10 years ago. We understand that OSFM is scheduling a public hearing in mid-October, but we have heard concerns that this could be after a determination of the state waiver, which would allow for the functional restart of the pipeline with no opportunities for public participation. We believe it would be helpful to invite public review and comment on the available information before any decision is finalized.

We would urge the OSFM to be as transparent as possible with the documents that are germane to public participation. The safety of these pipelines is a serious concern for many in our community, and it is important that the public is aware of the conditions of the pipelines and what is being done to make them operate safely.

The OSFM is a public agency working on behalf of the people of California, specifically charged with "safeguard[ing] our communities" from the inherent hazards in oil and gas transportation.[6] We are concerned that the people of California will be left holding the bag for the exorbitant clean-up costs if Sable, a speculative company with no operational assets, files for bankruptcy.

With the significant health, fiscal, and environmental risks posed with this restart, public participation is essential to ensuring that OSFM makes fully informed decisions. As an agency

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[2] Pipeline and Hazardous Materials Safety Administration, *Failure Investigation Report, Plains Pipeline, LP, Line 901, Crude Oil Release, May 19, 2015, Santa Barbara County, California*, pp. 13-14 (May 2016) [hereinafter "PHMSA Report"], available at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/PHMSA_Failure_Investigation_Report_Plains_Pipeline_LP_Line_901_Public.pdf.

[3] Santa Barbara County Administrative Draft of Draft EIR for Plains Pipeline Replacement Project, Section 5.6, p. 79.

[4] *Id.*

[5] *See Pathways for Restarting Pipelines*, OSFM, https://osfm.fire.ca.gov/what-we-do/pipeline-safety-and-cupa/pathways-for-restarting-pipelines (last visited Sept. 17, 2024).

[6] *Pipeline Safety and CUPA*, OSFM, https://osfm.fire.ca.gov/what-we-do/pipeline-safety-and-cupa (last visited Sept. 17, 2024).

acting on behalf of the public, it is important that OSFM understand the views of the public to maintain a level of trust in our government agencies. We respectfully request the following:

- Release all documents pertinent to Sable's restart, unless OSFM is prohibited from doing so by law;
- Conduct environmental review pursuant to the California Environmental Quality Act, to ensure consideration of potential environmental impacts before decisions are made; and
- Hold public meetings and invite public comment at each step of the restart process *before* making any determinations. As identified on the OSFM website, those steps would include, for example, implementation of the Risk Analysis, OSFM's consideration of a State Waiver, deferred maintenance that must be completed, and consideration of a Restart Plan[7].

We have grave reservations regarding the restart of CA-324 and CA-325, which have *already* caused a catastrophic oil spill, and which Sable intends to restart without effective protection from corrosion. Again, one governing body has already identified that proceeding in this manner would inevitably lead to another oil spill, one that could be twice the size of the 2015 disaster.[8]

Thank you for your consideration of our comments and your prompt attention to this matter.

Sincerely,

Monique Limón
Senator, District 19

Gregg Hart
Assemblymember, District 37

Scott Weiner
Senator, District 11

Dawn Addis
Assemblymember, District 30

John Laird
Senator, District 17

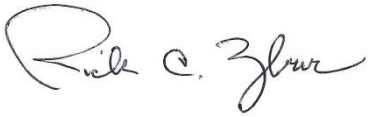
Steve Bennett
Assemblymember, District 38

[7] *Pathways for Restarting Pipelines*, OSFM, https://osfm.fire.ca.gov/what-we-do/pipeline-safety-and-cupa/pathways-for-restarting-pipelines (last visited Sept. 17, 2024).
[8] Santa Barbara County Administrative Draft of Draft EIR for Plains Pipeline Replacement Project, Section 5.6, p. 79.

Ben Allen
Senator, District 24

Jacqui Irwin
Assemblymember, District 42

Henry Stern
Senator, District 27



Rick Zbur
Assemblymember, District 51

Lena Gonzalez
Senator, District 33

Tina McKinnor
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Cc: Jim Hosler, Assistant Deputy Director, Pipeline Safety and CUPA

environmental
DEFENSE CENTER

September 27, 2024

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Mr. Daniel Berlant, State Fire Marshal
California Department of Forestry and Fire Protection
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Sacramento, CA 94244-2460
Via Email: Joe.Tyler@fire.ca.gov; Daniel.Berlant@fire.ca.gov

Re: Restart of CA-324 and CA-325: Office of State Fire Marshal's Obligation to Conduct Environmental Review; Renewed Request for Public Process

Dear Mr. Tyler and Mr. Berlant:

On behalf of Get Oil Out! ("GOO!"), Santa Barbara County Action Network ("SBCAN"), and the Environmental Defense Center ("EDC"),[1] we write to request that the Office of the State Fire Marshal ("OSFM") conduct environmental review of Sable Offshore Corporation's ("Sable") proposal to restart pipelines CA-324 and CA-325, pursuant to OSFM's obligations under the California Environmental Quality Act ("CEQA"). We also renew our request for a public process, which is appropriate under the circumstances and, in the case of Sable's request for a State Waiver, required by law.

As you know, Sable is seeking approval from OSFM to restart CA-324 and CA-325[2] (together, the "Las Flores Pipeline System") despite their lack of effective cathodic protection. As OSFM also knows, this lack of protection is ultimately what caused CA-324 to rupture in 2015, resulting in a catastrophic oil spill at Refugio Beach State Park. The spill closed public

[1] GOO! was formed in the wake of the 1969 Santa Barbara Oil Spill and continues to work to protect California from further oil and gas development and exploitation. SBCAN is a countywide grassroots organization that works to promote social and economic justice, to preserve our environmental and agricultural resources, and to create sustainable communities. EDC is a nonprofit public interest law firm that defends nature and advances environmental justice on California's Central Coast through advocacy and legal action.
[2] These pipelines were previously known as Lines 901 and 903 before they were reclassified as intrastate pipelines.

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parks and beaches, killed and injured wildlife, shut down fisheries, and destroyed sensitive habitats and cultural resources.[3]

Our clients were involved in the immediate response to the Refugio Oil Spill and remain concerned about the risks of operating the Las Flores Pipeline System. They have well-founded concerns that CA-324 and CA-325 cannot be safely restarted and, as to Sable, that this speculative company will not be able to responsibly operate the pipelines or fulfill its remediation obligations when another spill occurs.

Developments in the wake of the spill — namely, the discovery that these pipelines lack effective cathodic protection — have fundamentally altered the project that was envisioned when the pipelines were installed nearly four decades ago. Without cathodic protection, the risk of a spill from these pipelines is five times greater than was initially estimated.[4] Indeed, bringing the pipelines back online would not only invite another oil disaster on the Central Coast, but according to at least one governing body, all but ensure it.[5] But for OSFM's discretionary approvals here, no environmental impacts from these pipelines would occur.

Accordingly, in reviewing Sable's proposal to restart the pipelines, CEQA requires that OSFM prepare a new or subsequent Environmental Impact Report ("EIR") that considers the risks associated with operating these corroded pipelines without effective cathodic protection, which, to date, have not been evaluated. Thus, we urge OSFM to conduct additional environmental review *before* approving a restart of these pipelines, as the law requires.

I. OSFM Must Conduct Environmental Review under CEQA before Authorizing Sable to Restart Lines CA-324 and CA-325.

Pursuant to the 2020 Consent Decree entered in *U.S. v. Plains All American Pipeline*, Civil Action No. 2:20-cv-02415 (the "Consent Decree"), as well as state law passed in the wake of the Refugio Oil Spill, Sable has asked — or will ask — OSFM to approve (1) a Risk Analysis, (2) a State Waiver for the limited effectiveness of cathodic protection, and, ultimately, (3) a Restart Plan. Thus, cumulatively, Sable seeks approval from OSFM to restart the Las Flores Pipeline System without effective cathodic protection (the "Restart Project").

Should OSFM take the position that the proposed restart does not constitute a new "project" — which is subject to reasonable dispute[6] — that would not mark the end of its CEQA analysis or relieve its obligation to conduct environmental review.

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[3] California Department of Fish and Wildlife et al., *Refugio Beach Oil Spill Final Damage Assessment and Restoration Plan/Environmental Assessment*, p. 3 (June 2021) [hereinafter "NRDA"], available at: https://nrm.dfg.ca.gov/FileHandler.ashx?DocumentID=193144&inline.

[4] Santa Barbara County, Administrative Draft of Draft EIR for Plains Pipeline Replacement Project, Section 5.6, p. 79 [hereinafter "County Draft EIR"], attached hereto.

[5] *Id.*

[6] Having not transported oil or gas for nearly ten years, a restart of these pipelines would not simply be a return to the status quo, particularly in light of the State Waiver Sable is seeking. The Restart Project is fundamentally

If the Restart Project is not itself considered a "project," then OSFM's determinations here would constitute new approvals for the Celeron/All American and Getty Pipeline Project (the "Celeron Project"), which was the initial proposal to install and operate the Las Flores Pipeline System. Where, as here, an agency issues subsequent discretionary approvals for a project — *see* Part I.A., *infra* — it is required to examine the sufficiency of the project's prior EIR. (*Friends of the Coll. of San Mateo Gardens v. San Mateo Cnty. Cmty. Coll. Dist*. (2016) 1 Cal.5th 937, 951-52.)

The EIR for the Celeron Project (the "Celeron EIR")[7] was certified in 1985[8] — nearly forty years ago, and before the discovery that the Las Flores Pipeline System lacks effective cathodic protection. Because the findings in the prior EIR were premised on an effective cathodic protection system, and Sable is now proposing to operate the pipelines without such protection, CEQA requires that OSFM prepare a subsequent EIR. (*See* Pub. Res. Code, § 21166; CEQA Guidelines § 15162.)

A. OSFM's Approval of the Restart Project is Discretionary, not Ministerial, and Thus is Not Exempt from CEQA.

Compliance with CEQA may be excused where a proposed activity falls within certain statutory or categorical exemptions. (*See, e.g., Union of Medical Marijuana Patients, Inc. v. City of San Diego* (2019) 7 Cal.5th 1171, 1186.) The threshold statutory exemption is for "ministerial projects," "which are defined generally as projects whose approval does not require an agency to exercise discretion." (*Id.*; *accord* Pub. Res. Code, § 21080(b)(1); CEQA Guidelines § 15369.) However, because OFSM has wide latitude at each step of the restart process to approve, deny, or modify the Restart Project, OSFM's approval of the Restart Project is a discretionary decision that is not exempt from CEQA review.

1. Discretionary versus Ministerial Projects

Distinguishing discretionary projects from ministerial ones turns on whether the exercise of judgment or deliberation is required in making the decision. (CEQA Guidelines § 15357.) The "key question is whether the public agency can use its subjective judgment to decide whether and how to carry out or approve [the] project." (*Id.*; see also CEQA Guidelines § 15002(i).) "Whether an agency has discretionary or ministerial controls over a project depends

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different than the initial proposal to install and operate these pipelines in the 1980's, which was considered as a 30-year project. Restarting the pipelines would be akin to bringing online a new and different oil and gas operation that capable of causing significant environmental effects. (*See* Pub. Res. Code, § 21065; *see also* CEQA Guidelines § 15378(a) (defining "project" as an action "which has a potential for resulting in either a direct physical change in the environment or a reasonably foreseeable indirect physical change").)

[7] The Final EIR published in 1985 is a finalizing addendum to the 1984 Draft EIR. The preface of the Final EIR explains that the Final EIR is intended to be read "in conjunction with, rather than in place of, the Draft EIR/EIS that was released for public review on August 1, 1984." Thus, collectively, the two documents and their appendices form the project EIR.

[8] California State Lands Commission et al., *Final Environmental Impact Report Environmental Impact Statement*, (January 1985) [hereinafter "Final Celeron EIR"].

on the authority granted by the law providing the controls over the activity." (CEQA Guidelines § 15002(i)(2).)

Courts have developed a "functional test" to refine the distinction between discretionary and ministerial projects, which focuses on the scope of agency discretion. (*See Protecting our Water and Environmental Resources v. County of Stanislaus* (2020) 10 Cal.5th 459, 467.) The touchstone of the test "is whether the relevant 'approval process . . . allows the government to shape the project in any way [by requiring modifications] which could respond to any of the concerns which might be identified' by environmental review." (*Id.* (citations omitted).) "If so, the project is discretionary." (*Id.*)

2. Discretionary Aspects of OSFM Approval

As an initial matter, the Consent Decree, which controls and outlines the restart process, does not actually require that OSFM approve a restart or any of Sable's underlying applications. It vests OSFM with the authority to approve a Risk Analysis, State Waiver, and Restart Plan, but it does not set forth conditions under which OSFM must do so. Nor does it purport to limit the scope of OSFM's discretion in considering them. In fact, as discussed further below, the Consent Decree specifically acknowledges OSFM's wide latitude to approve or modify the Restart Project.

Indeed, OSFM has itself acknowledged the broad discretion it has here in reviewing the Restart Project. The OSFM website, for example, notes that the Consent Decree only specifies "the *minimum requirements* for restarting CA-324 and CA-325."[9] Per Deputy State Fire Marshal Kara Garret, OSFM may impose "other safety requirements deemed necessary by our office," suggesting that it generally has discretion to shape the Restart Project. [10] The County, which has also weighed in on OSFM's discretion here, was even more explicit: "discretionary actions to permit restart activities are needed from [OSFM]."[11]

Such discretion, which can be exercised to shape the Restart Project, is apparent at each step of the restart process.

Take OSFM's Risk Analysis review, for example. Pursuant to 19 C.C.R. section 2110(b), OSFM must assess the "adequacy" of a Risk Analysis by evaluating, among other things, what constitutes "best available technology," the "assumptions and conclusions reached by an operator," and any "additional information that may be relevant to . . . .assessing or determining the adequacy of a [R]isk [A]nalysis." Each of these considerations, and the determination of

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[9] *Pathways for Restarting Pipelines*, Office of the State Fire Marshal, https://osfm.fire.ca.gov/what-we-do/pipeline-safety-and-cupa/pathways-for-restarting-pipelines (last visited September 26, 2024).
[10] Giana Magnoli, *Sable Offshore Corp. Takes Over Exxon's Santa Barbara Oil Assets, Sets Sights on Restarting Operations*, Noozhawk (February 14, 2024) (emphasis added), available at: https://www.noozhawk.com/sable-offshore-corp-takes-over-exxons-santa-barbara-oil-assets-sets-sights-on-restarting-operations.
[11] Santa Barbara County, *Revised Notice of Preparation*, pp. 2-3 [hereinafter "Revised NOP"], available at https://files.ceqanet.opr.ca.gov/170616-2/attachment/kMgGnx0tQr16ZTEvxK9MMeqNrLQO9Zgzm79wtnPIiz9ypKehMDgvTH0hm3te5DOx4NMf_ebkpJow0wNe0.

adequacy as a whole, inherently requires that OSFM exercise a large degree of subjective judgment — a hallmark of discretion. (*See* CEQA Guidelines § 15357.) Moreover, OSFM is explicitly authorized to condition its acceptance of a Risk Analysis on additional requirements or modifications. (19 C.C.R. § 2112(d).) "If [an] agency is empowered to disapprove or condition approval of a project . . . the project is discretionary." (*Protecting Our Water*, 10 Cal.5th at 494.)

The State Waiver process is likewise replete with agency discretion. The federal statute authorizing OSFM to issue a State Waiver provides that a state authority "*may* waive compliance with a safety standard," but it does not *require* approval of a waiver, and it does not set forth specific conditions under which OSFM may approve a waiver. (49 U.S.C. § 60118(d) (emphasis added).) It suggests only that a waiver may be granted on terms that OSFM "considers appropriate," which is echoed in our state statutory scheme that regulates safety exemptions. (*See* 49 U.S.C. § 60118(c), (d); Gov. Code, § 51011(b).) In other words, whether to grant a waiver, and under what conditions, is entirely at the discretion of OSFM. The Consent Decree recognizes as much, stating that "[n]othing in this CD shall be construed to limit the authority of [] OSFM to require additional terms or conditions in the State Waiver."[12] Notably, review of a Special Permit — the federal equivalent to a State Waiver — generally requires environmental review at the federal level.[13]

As to the Restart Plan, it appears to be a creature of the Consent Decree and lacks specific statutory or regulatory guidance. However, the Consent Decree requires that the Restart Plan include, for example, "*adequate* patrolling" and "*sufficient* surveillance."[14] Such conditions are imbued with ambiguity, and they ultimately require OSFM to exercise its subjective judgment to determine whether they are met. Ambiguous terms that "permit a great degree of latitude in the review of [] plans and are not subject to mechanical application" suggest discretionary action. (*Natural Resources Defense Council, Inc. v. Arcata Nat. Corp.* (1976) 59 Cal.App.3d 959, 970.)

In sum, OSFM's review of the Restart Project — and each underlying approval — necessarily requires that it use its subjective judgment. And, OSFM is authorized at each step of the approval process to condition and/or modify the project to address specific safety concerns and environmental hazards. Thus, the Restart Project is plainly a discretionary project that is not exempt from CEQA review. (*See Protecting our Water*, 10 Cal.5th at 467 (outlining the "functional test").)

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[12] Consent Decree, at Appendix B, Condition 1(E), U.S. v. Plains All American Pipeline, Civil Action No. 2:20-cv-02415 (March 13, 2020) [hereinafter "Consent Decree"], available at https://www.epa.gov/sites/default/files/2020-03/documents/plainsallamericanpipelinelp.pdf.

[13] *See generally* U.S. Department of Transportation Pipeline Safety and Hazardous Materials Safety Administration, *Final Environmental Assessment and Finding of No Significant Impact* (October 2018), available at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-08/2017-0155-HECO-Waiau-Pipeline-SP-FEA-and-FONSI.pdf.

[14] Consent Decree, *supra* note 12, at Appendix D, Conditions 1(B)(2), (3), emphasis added.

B. OSFM Must Prepare a Subsequent EIR Before Approving the Restart Project.

Again, where an agency issues subsequent discretionary approvals for a project, it is required to examine the sufficiency of the project's prior EIR. (*Friends of the Coll. of San Mateo Gardens*, 1 Cal.5th at 951-52.) That inquiry is two-fold. (*Id.*) First, the agency must consider whether the prior EIR retains any "informational value" to inform its subsequent determinations. (*Id.*) If it does not, then it must prepare a new EIR. (*Id.*) If it does, then the agency must evaluate whether additional environmental review is warranted under Public Resources Code section 21166. (*Id.*)

Section 21166 requires additional environmental review when (1) certain new information, which was not known and could not have been known at the time the EIR was certified as complete, becomes available; (2) substantial changes occur with respect to the circumstances under which the project is being undertaken which will require major revisions in the EIR; or (3) substantial changes are proposed in the project which will require major revisions of the EIR. (Pub. Res. Code § 21166; CEQA Guidelines § 15162; *Friends of the Coll. of San Mateo Gardens*, 1 Cal.5th at 943.) The proposal to restart the Las Flores Pipeline System despite the recent discovery that the pipelines lack effective cathodic protection warrants subsequent review under each of the Section 21166 considerations.

1. The Discovery that the Las Flores Pipeline System Lacks Effective Cathodic Protection Constitutes New Information that Requires OSFM to Prepare a Subsequent EIR.

Under CEQA, additional environmental review is required when

> New information of substantial importance, which was not known and could not have been known with the exercise of reasonable due diligence at the time the previous EIR was certified as complete or the negative declaration was adopted, shows . . . :
>
> . . .
>
> (B) Significant effects previously examined will be substantially more severe than shown in the previous EIR.

(CEQA Guidelines § 15162(a)(3)(B).)

a. The Discovery that the Pipelines Lack Effective Cathodic Protection is "New Information of Substantial Importance."

The Celeron Project was proposed as a pipeline system that would have effective cathodic protection to prevent corrosion. And, in evaluating the environmental effects of the project, the Celeron EIR understood that to be true.[15]

However, as we unfortunately now know, that is not the case. In the wake of the 2015 Refugio Oil Spill, the Pipeline and Hazardous Materials Safety Administration ("PHMSA") determined that the rupture in CA-324 was a result of progressive external corrosion, and that the Las Flores Pipeline System's cathodic protection system — intended to prevent such corrosion — was ineffective.[16] That information was not known until 2016 — thirty-one years after the Celeron EIR was certified.

As to buried, insulated lines more generally, it was previously understood that they could be susceptible to aggressive corrosion despite the implementation of cathodic protection. But no formal consensus existed as to the ineffectiveness of cathodic protection prior to a National Association of Corrosion Engineers ("NACE") report that was issued in 1992 — seven years after the Celeron EIR was certified.[17]

Thus, the Las Flores Canyon System's extensive corrosion issues and coating/insulation failures were unknown and unaccounted for in the antiquated Celeron EIR. Indeed, the Celeron EIR indicates staff were unaware that cathodic protection would be ineffective, as it states that the project "would be equipped with a cathodic protection system to reduce or prevent pipeline corrosion."[18]

The relative importance of this new finding cannot be understated. It fundamentally alters the nature of the Celeron Project and upends the foundational underpinnings of the Celeron EIR. Indeed, in predicting the likelihood of an oil spill — the primary environmental impact considered — the Celeron EIR relied on cathodic protection as a design specification that "would reduce the probability of an event [oil spill] occurring."[19] While the lead agency likely expected its predictions of the probability of an oil spill to be reasonable, not perfect, the difference in effectiveness of cathodic protection on insulated pipelines meant that the risk of a leak was *five times higher* than anticipated, as discussed further below.[20]

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[15] Final Celeron EIR, *supra* note 8, at 2-57 (citing "cathodic corrosion protection" as a measure that would be "very effective" in reducing the risk of groundwater contamination from an oil spill); *see also id.* at 2-94, 2-106.
[16] Pipeline and Hazardous Materials Safety Administration, *Failure Investigation Report, Plains Pipeline, LP, Line 901, Crude Oil Release, May 19, 2015, Santa Barbara County, California*, pp. 3, 14 (May 2016) [hereinafter "PHMSA Report"], available at: https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/PHMSA_Failure_Investigation_Report_Plains_Pipeline_LP_Line_901_Public.pdf.
[17] *Id.* at Appendix O, p. 7.
[18] California State Lands Commission et al., *Draft Environmental Impact Report Environmental Impact Statement*, p. H-35 (August 1984) [hereinafter "Draft Celeron EIR"].
[19] Final Celeron EIR, *supra* note 8, at Appendix 4.3.
[20] County Draft EIR, *supra* note 4, at Section 5.6, p. 79.

Accordingly, the limited effectiveness of cathodic protection in the Las Flores Pipeline System is incredibly consequential to an analysis of the pipelines' environmental impact. And, as discussed, that information was only discovered after the 2015 spill. Thus, it constitutes "new information of substantial importance" for purposes of Section 21166. (*See, e.g., Sec. Env't Sys., Inc. v. S. Coast Air Quality Mgmt. Dist.* (1991), 229 Cal.App.3d 110, 124 (holding that new information that undermined a key assumption used to evaluate the impacts of a project was of substantial importance).)

b. Without Effective Cathodic Protection, the Effects Considered in the Celeron EIR Substantially Increase in Severity.

As noted, without cathodic protection, the risk of a spill from the Las Flores Pipeline System increases dramatically.

As one governing body already found, another spill would not be a matter of if, but when.[21] According to a recent analysis conducted by the County of Santa Barbara, the lack of an effective cathodic protection system increases the likelihood of an oil spill by *five times*:

> The spill frequencies are adjusted for the pipeline potential higher failure rate due to the compromised cathodic protection system and the potential for corrosion under the insulation issues. This correction is based on the CSFM report (CSFM 1993) indicating a five times increase in failure frequencies for pipelines that are not equipped with cathodic protection over the average failure rate.[22]

The County concluded that restarting the pipelines without effective cathodic protection could result in a spill every year, and a rupture (a spill greater than five barrels) every four years.[23] And, a spill in the coastal zone could be nearly twice the size of the 2015 spill.[24]

The Celeron EIR assessed possible environmental impacts from pipeline operations in part by considering the likely frequency of spills.[25] However, as noted above, the EIR's spill frequency estimates were expressly premised on an effective cathodic protection system; without such protection, the likelihood of a spill is five times greater than the Celeron EIR estimated. By using an erroneous estimate of spill frequency to assess the project's environmental impacts, the Celeron EIR necessarily underestimated the severity of those impacts, and its impact findings are unreliable.

An increased frequency of spills could also lead to environmental impacts that were never even considered in the Celeron EIR. Indeed, the aggregate effects of multiple oil spills in

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[21] *See id.*
[22] *Id.* at Section 5.6, p. 78.
[23] *Id.* at Section 5.6, p. 79.
[24] *Id.* at Section 5.6, p. 78.
[25] *See, e.g.,* Final Celeron EIR, *supra* note 8, at 1-20, 1-24.

sensitive areas were never specifically addressed. For example, if another spill were to occur in an area impacted by the 2015 spill, damage to still-recovering coastal flora and fauna could be irreparable. Likewise, the compound effect of multiple spills into certain groundwater systems may be unmitigable.

With the possibility of five times as many spills as initially expected, the potential cumulative environmental impacts over the lifetime of the Celeron Project are far more severe than the Celeron EIR anticipated. Thus, OSFM is required to prepare a subsequent EIR before approving the Restart Project. (*See* CEQA Guidelines § 15162(a)(3)(B); *Sec. Env't Sys.*, *Inc.*, 229 Cal.App.3d at 124.)

2. OSFM Must Prepare a Subsequent EIR due to Substantial Changes in the Project and the Circumstances under which the Project is Being Undertaken.

OSFM is also required to prepare a subsequent EIR due to the proposed changes to the Celeron Project and the substantial changes with respect to the circumstances under which the project is being undertaken. (Pub. Res. Code, § 21166(a), (b).) These changes, which stem from the failure of pipelines' cathodic protection system, create new significant effects and a substantial increase in the severity of previously identified significant effects. (CEQA Guidelines § 15162(a)(1), (2).)

a. The Failure of the Cathodic Protection System and Resulting Corrosion Constitutes a Change in Circumstances that Requires a Subsequent EIR.

As discussed above, the Celeron EIR relied on a cathodic protection system to prevent corrosion and minimize oil spill impacts.[26] It stated that "protection of a pipeline from corrosion is of critical importance" and "the entire pipeline would be protected from corrosion with cathodic protection systems . . . ."[27] And, it cited "cathodic corrosion protection" as a measure that would be "very effective" in reducing the risk of groundwater contamination from an oil spill.[28] The cathodic protection system failed, however, causing the pipelines to corrode and eventually rupture.[29]

As noted, the lack of an effective cathodic protection system increases the likelihood of an oil spill by five times and leads to pervasive corrosion throughout a pipeline system.[30] Operating the Las Flores Pipeline System without effective cathodic protection was neither anticipated nor reviewed in the Celeron EIR.

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[26] *See id.* at 4-53, 4-54, 4-55; Draft Celeron EIR, *supra* note 18, at H-35.
[27] Draft Celeron EIR, *supra* note 18, at 2-5, 4-106, 4-117.
[28] Final Celeron EIR, *supra* note 8, at 2-57; *see also* Final Celeron EIR at 2-94, 2-106.
[29] PHMSA Report, *supra* note 16, at 3, 13.
[30] County Draft EIR, *supra* note 4, at Section 5.6, p. 78.

This change in circumstances means more possible spills over the lifetime of the project, which, as explained above, will result in additional and more severe environmental impacts than the Celeron EIR accounted for. (*See* Part II.B.2, *supra*.) Thus, OSFM must prepare a subsequent EIR to evaluate this change and the potential impacts it will cause. (CEQA Guidelines § 15162(a)(2).)

Indeed, EIRs are specifically intended to "provide public agencies and the public in general with detailed information about the effect which a proposed project is likely to have on the environment." (Pub. Res. Code § 21061.) The failure to prepare a subsequent EIR improperly deprives the public "of meaningful participation regarding the issue" of environmental harm cause by changed circumstances. (*Mira Monte Homeowners Assn. v. County of Ventura* (1985) 165 Cal.App.3d 357, 365.)

b. The Change in Project Design to Operate Without Effective Cathodic Protections Requires Preparation of a Subsequent EIR.

The Celeron Project was proposed as an oil and gas pipeline system that would have an effective cathodic protection system to prevent corrosion. And that is the project that was ultimately approved.

Now, however, Sable is seeking a State Waiver to operate the Las Flores Pipeline System without an effective cathodic protection system and well past its 30-year projected lifespan.[31] As discussed above, effective cathodic protection was a foundational aspect of the Celeron Project and its environmental review.[32] Indeed, as repeatedly alluded to throughout the Celeron EIR, such protection was an essential design element of the project, and the principal technology relied on to prevent a spill.[33]

Restarting the pipelines without an effective cathodic protection system represents a grave departure from the project that was initially envisioned and approved. (*See City of San Jose v. Great Oaks Water Co.* (1987) 192 Cal.App.3d 1005, 1015-17 (change in how water would be supplied to a project required additional environmental review).) The public, and other responsible agencies reviewing aspects of this project, have a right to understand how the project will be modified to address the defective cathodic protection system, and how the change affects the risk of another oil spill.

As explained at length above, operating without effective cathodic protection will result in additional and more severe environmental impacts than the Celeron EIR accounted for. (*See* Part II.B.2, *supra*.) This increase in severity of impacts, directly related to the failure of the cathodic protection system, requires the OSFM to prepare a subsequent EIR before deciding

[31] Draft Celeron EIR, *supra* note 18, at 2-35.
[32] *See, e.g.,* Final Celeron EIR, *supra* note 8, at 2-57, 2-94, 2-106, 4-53, 4-54, 4-55, H-35; Draft Celeron EIR, *supra* note 18, at 2-5, 4-106, 4-117.
[33] *See, e.g.,* Final Celeron EIR, *supra* note 8, at 2-57, 2-94, 2-106, 4-53, 4-54, 4-55, H-35; Draft Celeron EIR, *supra* note 18, at 2-5, 4-106, 4-117.

whether to approve the State Waiver or the Restart Project as a whole. (Pub. Res. Code, § 21166(a).)

II. OSFM Should, and in Some Cases Must, Engage the Public Before Issuing Any Approvals Associated with the Restart Project.

Our clients and a number of other community organizations have twice asked OSFM for transparency and public engagement as it considers whether to approve the Restart Project. But OSFM has yet to hold any public meetings, invite public review and comment of any of Sable's applications, or release pertinent documents related to its determinations.

OSFM is a public agency, working on behalf of the people of California, that is charged with "safeguard[ing] our communities" from the hazards inherent in oil and gas transport.[34] Public participation is essential to ensuring that OSFM makes fully informed decisions, that OSFM understands the views of the public on whose behalf it is acting, and that the public maintains trust in our government agencies.

Should OSFM approve the Restart Project, our clients and our community will bear the consequences. We will be the ones who suffer from poorer air quality.[35] When another oil spill occurs, we will be the ones who watch dead mammals wash up on the shore, are deprived of access to the beaches we cherish, and whose businesses will suffer. And it may very well be the people of California who are forced to foot the bill to clean up a spill, or eventually, to decommission these facilities. **All we are asking for is a voice in a decision that will directly and substantially impact our community and the future of the Central Coast.**

Not only is public participation uniquely appropriate here, but in the case of the State Waiver, it is required by law.

OSFM's authority to issue a State Waiver comes from 49 U.S.C. § 60118(d), which provides that it "may waive compliance with a safety standard" — here, the requirement for effective cathodic protection — "*in the same way and to the same extent* that the Secretary [of Transportation] may waive compliance under subsection (c) of this section." (Emphasis added.) Subsection (c), in turn, explicitly states that "[t]he Secretary may act on a waiver . . . *only* after notice and an opportunity for a hearing." (49 U.S.C. § 60118(c)(B) (emphasis added).)

Thus, while OSFM has the discretion to approve a State Waiver, it can only do so by following the explicit procedures set forth in 49 U.S.C. § 60118, including providing the public with notice and an opportunity for a hearing. OSFM's failure to allow for public participation would void OSFM's approval of the waiver.

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[34] *Pathways for Restarting Pipelines*, Office of the State Fire Marshal, https://osfm.fire.ca.gov/what-we-do/pipeline-safety-and-cupa/pathways-for-restarting-pipelines (last visited September 26, 2024).
[35] *Pollution Mapping Tool Data*, California Air Resources Board, https://www.arb.ca.gov/ei/tools/pollution_map/ (last visited September 26, 2024).

Accordingly, we respectfully request that, in addition to conducting environmental review, (1) OSFM release all documents pertinent to the Restart Project and (2) hold public hearings and solicit public comment at each step of the restart process *before* making any determinations.

III. Conclusion

The circumstances surrounding the operation of these pipelines have substantially changed since they were initially evaluated and installed. In the last ten years, the pipelines have aged past their expected lifespan, were found to lack effective cathodic protection, and caused a catastrophic oil spill. Together, these developments have so fundamentally altered the nature of operations that a request to restart the pipelines, after ten years of dormancy, requires new environmental review.

Indeed, in light of the substantial increase in the risk of an oil spill from these pipelines, the environmental impacts from the Restart Project would be different and more severe than those considered in the Celeron EIR and have not been properly evaluated. Thus, CEQA requires that OSFM prepare either a new or subsequent EIR to evaluate the risks associated with operating a corroded pipeline without an effective cathodic protection system.

Lastly, we renew our request for public engagement and transparency in OSFM's review of the Restart Project. The Restart Project is a matter of profound public import with the potential to impact our community for years to come. We again ask OSFM to release all pertinent documents related to its review of the project, and to hold public hearings before it makes any further determinations, as is appropriate under the circumstances and required by law.

Thank you for your consideration.

Sincerely,

Linda Krop,
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Attachments:

1. Excerpt of Santa Barbara County Administrative Draft of Draft EIR for Plains Pipeline Replacement Project

2. Excerpt of 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)

ATTACHMENT 1

Impacts related to Hazardous Materials and Risk of Upset would only be related to maintenance and construction activities and these maintenance activities would have a minor impact on risk due to the potential for localized spills of hydraulic or diesel oils. **Impact RISK.1, RISK.2, RISK.3** would not be applicable and mitigation measures RISK.2-1 through RISK.2-7 would not be applicable. Impacts would therefore be **insignificant**.

Construction activities related to valve stations, pump stations and some segments of the pipeline that could be abandoned could potentially produce an increased risk of wildfires during construction, and **RISK.4** would still be applicable and mitigation measures RISK.4-1 through RISK.4-4 would still be applicable. Impacts related to **Impact RISK.4** and wildfires would therefore be **significant but mitigable**.

No Project, Existing Pipeline Restart Alternative

Under this alternative, the existing pipeline would be utilized instead of a new pipeline being installed, and transportation of crude oil would occur through the existing pipeline. The existing pipeline would be brought into compliance with existing requirements related to AB 864 and CSFM best available technologies (BAT), including the installation of additional valves along the pipeline route. The Applicant would have to apply to the CSFM for a waiver to utilize the existing pipeline since the existing pipeline is subject to corrosion under insulation, which could affect the efficacy of cathodic protection systems. Generally, a pipeline is not allowed to operate with ineffective cathodic protection systems. There is uncertainty as to whether the Applicant could demonstrate to the CSFM that the pipeline could be operated safely, and therefore this variation and the variation above (no Project, No Pipeline Alternative) are both addressed.

Assuming that a CSFM waiver is granted, the Applicant would have to install additional valves along the pipeline in order to comply with AB 864 and BAT requirements, similar to the proposed Project pipeline design. The installation of these additional valves would require some construction activities and some limited clearing at multiple locations along the pipeline ROW.

The existing pipeline is insulated, and therefore there would be no need for heaters at the Sisquoc Pump Station or the installation of the gas pipeline.

The installation of valves would most likely be at locations similar to the proposed Project valve installations as the pipeline would follow a similar ROW and similar terrain.

Hazards are associated with risks to the public from a spill and subsequent fire, as well as impacts from a spill to the environment, impacts to schools and potential wildfire impacts. The existing pipeline is a larger diameter pipeline, and therefore the draindown spill volumes would be larger than the proposed Project. This results in potentially larger spills and larger fires, impacting more people, as well as larger spills to the environment. In addition, the frequency of a spill from the existing pipeline would be higher due to its age and the potential for the cathodic protection to be compromised by the insulation. These factors have been incorporated into the analysis presented below.

Risks to Public Safety

Impact RISK.1 describes the potential spill sizes and the estimated frequency of spills from the pipeline system and the potential for immediate (fires, etc.) health impacts on the public.

Crude Pipeline Spill Volumes

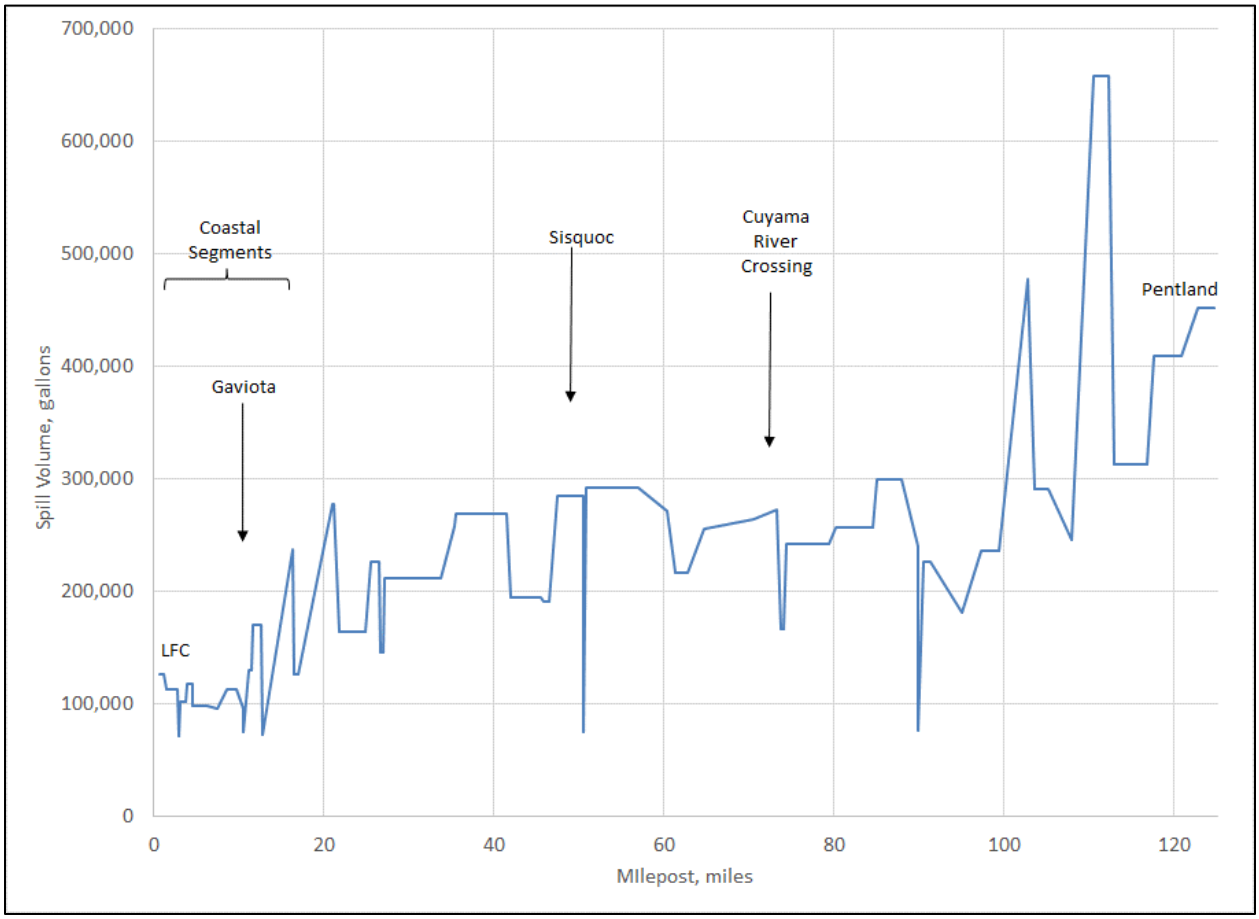
The spill volumes for this alternative were calculated based on the pipeline size, which would be larger than the proposed Project, and the associated terrain for different segments of the pipeline. The Applicant

provided a risk assessment for the proposed Project and this analysis was utilized to estimate the spill volumes associated with a larger pipeline size. Figure 5.6-11 shows the estimated spill volumes along the pipeline route for each segment as a worst case for that segment. The worst-case sized spill volume is shown in Table 5.6-16 for the different portions of the crude oil pipeline alternative.

Crude Pipeline Spill Frequencies

Spill frequencies from a crude pipeline are based on the PHMSA failure rates for the California pipeline database. The PHMSA base failure rate for crude oil pipelines is shown in Table 5.6-17. The spill frequencies are adjusted for the pipeline potential higher failure rate due to the compromised cathodic protection system and the potential for corrosion under the insulation issues. This correction is based on the CSFM report (CSFM 1993) indicating a five times increase in failure frequencies for pipelines that are not equipped with cathodic protection over the average failure rate. In addition, because the existing pipeline is older, it could experience a higher failure rate due to age. However, the CSFM study indicated a minimal increase in failure rate for pipelines that are less than 40 years old and the PHMSA database used to estimate the base failure rate includes many older pipelines. Therefore, only the five times factor was applied as an estimate of the increased failure rate for this pipeline.

Figure 5.6-11 No Project – Existing Pipeline Restart Alternative Spill Volume by Segment Milepost



Source: based on Applicant QRA and EFRD 2019, with adjustments for the size of the existing pipeline.

Table 5.6-16 No Project – Existing Pipeline Restart Alternative Crude Pipeline Worst Case Spill Volumes

Location	Proposed Project - Maximum Spill Volume, gallons	Alternative - Maximum Spill Volume, gallons
LFC – Gaviota Plant	84,000	126,000
Gaviota – Sisquoc	131,040	284,594
Sisquoc - Pentland	198,030	657,893
Coastal Segments	117,600	237,344

Source: based on Applicant QRA and EFRD 2019, with modification to address spill duration of 60 minutes. Coastal segments include up to valve station 2-500. Includes the installation of additional valve stations as per the proposed Project locations.

Table 5.6-17 No Project – Existing Pipeline Restart Alternative Crude Pipeline Spill Frequencies

Location	Spill Frequency	Return Period, years rupture/leak/total
PHMSA California Crude oil base rate	1.62 per 1,000-mile years	-
Adjustment due to Pipeline Condition	5.3 factor	-
PHMSA Adjusted Rate	8.56 per 1,000-mile years	-
Failure rate for L901R (49.2 miles)	0.43 failures per year	9/3/2 years
Failure Rate for L903R (74.1 miles)	0.63 failures per year	6/2/2 years
Failure Rate for L901R + L903R	1.07 failures per year	4/1/1 years

Source: based on Applicant QRA and EFRD 2019 with CSFM 1991 adjustment factor. PHMSA data since 2010. The return period is the anticipated period between releases. Includes leaks and ruptures.

Crude Pipeline Population Densities

The population densities along the route are based on estimates for remote, rural, low density and high-density areas with some additions for highways. The population densities are similar to those used for the proposed Project except for the area through the City of Buellton, since the existing pipeline would pass through the City of Buellton and the proposed Project would pass around the City of Buellton to the west.

Crude Pipeline Fires

In the event of a spill of oil and subsequent ignition resulting in a pool fire, the heat (i.e., thermal radiation) from the fire could result in a serious injury or fatality. The assumptions for impacts would be the same as for the proposed Project.

Gas Pipeline

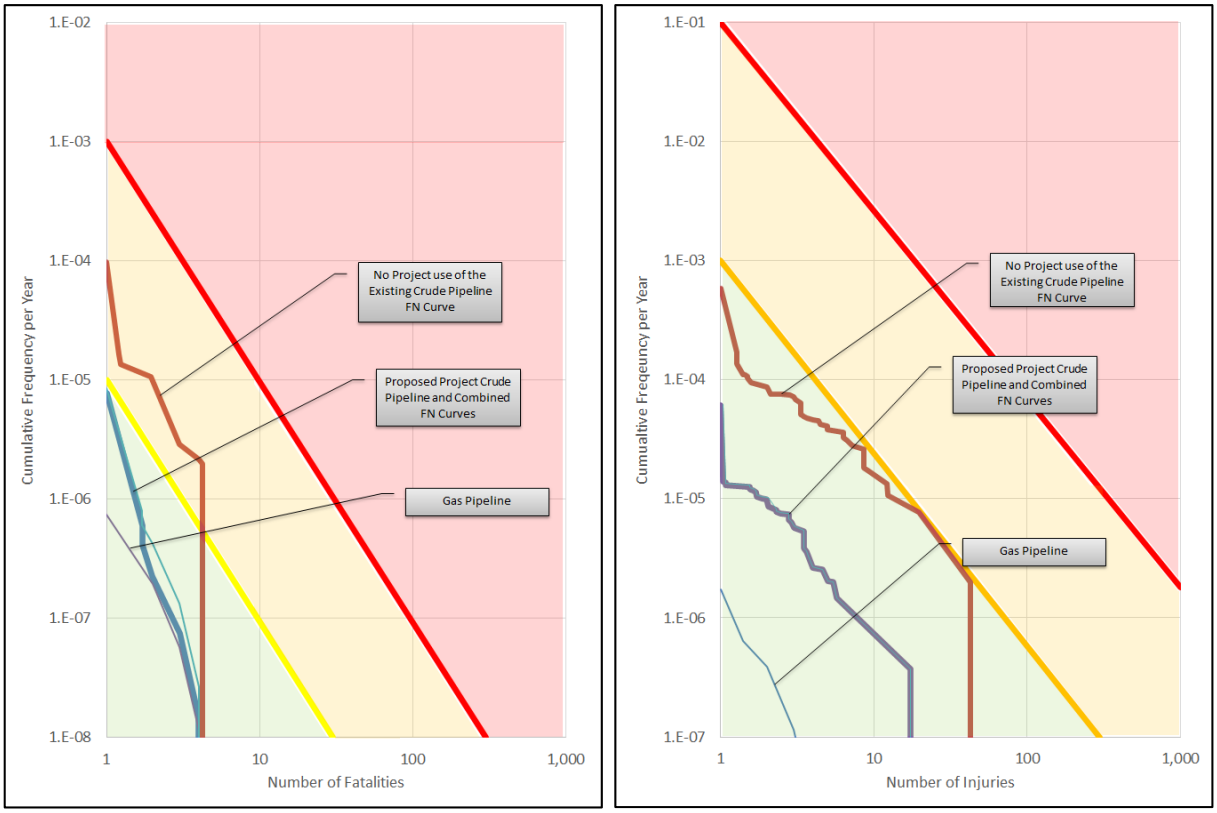
The proposed gas pipeline would not be installed as part of this alternative since heaters at Sisquoc would not be installed.

Alternative Pipeline: Public Safety Risk

The combination of scenario frequency and consequences is combined to estimate risk using FN curves. FN curves are depictions of the risk levels of a project and show the frequency (F) of scenarios that could produce a given fatality or injury level (N) or greater. These are presented for the proposed Project in **Impact RISK.1**. Santa Barbara County has established risk thresholds that use societal risk profiles (FN curves) to determine the significance of hazardous material releases. These FN curves address both injury and fatality. The Santa Barbara County's adopted thresholds are generally applicable to fixed facilities and pipelines. The risk FN curves are shown in Figure 5.6-12 and are based on the FN curves developed as part of the Plains 2019 QRA analysis, with adjustments for the existing pipeline (increased pipeline diameter

and failure frequency). The FN curves would be located within the amber region, and the impacts to public health due to pipeline releases would be **significant and unavoidable.**

Figure 5.6-12 No Project – Existing Pipeline Restart Alternative Pipeline Risk FN Curves



Source: Plains 2019 with modifications

Risks to the Environment

A spill of crude oil from the pipeline could impact resources in the vicinity of the pipeline ROW. See Section 5.2 Biological Resources, Section 5.4 Cultural Resources and Section 5.9 Hydrology and Water Quality for a discussion of the impacts of a crude oil spill on biological, hydrological and cultural resources along the crude oil pipeline ROW.

Crude Pipeline Spill Volumes

The spill volumes are discussed above under **Impact RISK.1**. For the public health assessment under **Impact RISK.1**, a worst-case spill shutdown time of 15 minutes was used due to the already conservative analysis for fires and impacts to the public used in the QRA. However, for spills that could affect the environment, a longer duration is used. As evidenced by the May 2015 Refugio spill, there is the potential for a pipeline shutdown to take longer than 15 minutes.

Crude Pipeline SCADA System

The SCADA system used for the alternative would be the same as that used for the proposed Project since the SCADA system would be required to be updated per CSFM and AB864 requirements.

Proposed Project Pipeline: Spills Affecting Marine Resources

Portions of the pipeline extend along the Santa Barbara County coastline. A crude oil spill could drain from the spill location through existing culverts or drainages and enter the marine environment. This is what occurred during the May 2015 Refugio Beach spill. An estimated 43 percent of the oil entered the ocean from the Refugio spill location, which was an estimated 750-foot pathway from the ocean shoreline. Because the proposed pipeline is located onshore at various distances from the shoreline, a rupture at different locations spilling the same amount of oil could allow for oil to enter the marine environment. Assuming a linear function of oil being trapped and adsorbed onshore with distance, the maximum amount of oil could enter the ocean where the pipeline is closest to the ocean and potential worst-case spill volumes are large. An estimated maximum amount of 71,621 gallons of crude oil could enter the ocean at the worst-case spill location. An estimated 11.8 miles of the 16.6-mile coastal portion (71 percent) of the pipeline would be vulnerable to spills entering the ocean if a spill were to occur along any of those segments and the adsorption rate were similar to that which occurred during the Refugio spill. This assumes that no rain event is occurring and that drainages are not flowing.

There are a number of variables affecting the amount of oil that could reach the ocean from an onshore spill, including the terrain, the location of drainages under the freeway and the railroad tracks, the soil type, and extent of rocky interfaces as well as the amount of moisture. During a rain event, when drainages and creeks are flowing, a spill into the waterways could follow the flow and enter the marine environment more readily. A spill under these conditions would also have more extensive terrestrial impacts and reach the marine environment more readily but would also be subjected to turbulence and mixing along the drainages.

For inland areas, the area with the largest potential impacts is along the Cuyama River. Based on the elevation profile and the spill volumes, the maximum spill volume along the Cuyama River segments of the pipeline (between proposed Project valve 3-800 and 5-400 nearest the Cuyama River) and using the absorption rate as seen in the Refugio spill, a spill along the Cuyama River portion of the pipeline could impact resources a distance as far as about 3,200 feet, which means that pipeline segments within about 3,200 feet of the Cuyama River could potentially impact the river in the event of a spill.

Potential Impacts

Depending on the location of the spill, the environmental conditions, and the biological resources present, Impact RISK.2 short and long-term effects to biological resources associated with a crude oil spill has the potential to be significant and unavoidable. Mitigation measures RISK.1-1 through RISK.1-7 would apply. Due to the increased size and frequency of spills, this significant and unavoidable impact would be a greater severity than that presented by the proposed Project.

Risks to Schools

For **Impact RISK.3** (schools), the pipeline construction activities for the existing pipeline would only affect areas near the proposed valve installations. The existing pipeline is located about 500 feet from the Oak Valley School in western Buellton. In order to address the risk levels to this school, the California Department of Education (CDE) school siting risk protocol was utilized to determine the risk levels.

The assessments demonstrated that the risk levels are acceptable under the CDE Risk Protocols with a Total Individual Risk/Individual Risk Criteria (TIR/IRC) ratio of 0.29, with a 1.0 TIR/IRC ratio being the CDE Protocol threshold. It is important to note that the CDE protocol examines the individual risk at the closest school and does not examine the risks cumulatively along the entire pipeline route. Because the CDE

ATTACHMENT 2

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

Table of Contents

Executive Summary

At approximately 10:55 a.m. Pacific Daylight Time (PDT) on May 19, 2015, the Plains Pipeline, LP (Plains), Line 901 pipeline in Santa Barbara County, CA, ruptured, resulting in the release of approximately 2,934 barrels (bbl) of heavy crude oil.[i] An estimated 500 bbl of crude oil entered the Pacific Ocean. Line 901 is a 24-inch diameter buried, insulated pipeline which extends approximately 10.7 miles in length and transports heated crude oil from Exxon Mobil's storage tanks in Las Flores Canyon westward to Plains' Gaviota Pumping Station. On May 21, 2015, the Pipeline and Hazardous Materials Safety Administration (PHMSA), a regulatory agency within the U.S. Department of Transportation, issued a Corrective Action Order (CAO) that required the operator to shut down Line 901. Concurrent with the issuance and implementation of the CAO, PHMSA conducted an investigation to identify causal factors that contributed to the occurrence and size of the crude oil release. As the failure investigation progressed, the CAO was amended to address additional safety concerns that were identified. On June 18, 2015, Line 901 was purged and filled with inert nitrogen to enhance safety during the investigation and development of a remedial action plan.[ii] No fatalities or injuries occurred as a result of this rupture and release. The spill resulted in substantial damage to natural habitats and wildlife.

PHMSA's findings indicate that the proximate or direct cause of the Line 901 failure was external corrosion that thinned the pipe wall to a level where it ruptured suddenly and released heavy crude oil. PHMSA's investigation identified numerous contributory causes of the rupture, including:

1) Ineffective protection against external corrosion of the pipeline

- The condition of the pipeline's coating and insulation system fostered an environment that led to the external corrosion.
- The pipeline's cathodic protection (CP) system was not effective in preventing corrosion from occurring beneath the pipeline's coating/insulation system.

2) Failure by Plains to detect and mitigate the corrosion

- The in-line inspection (ILI) tool and subsequent analysis of ILI data did not characterize the extent and depth of the external corrosion accurately.

3) Lack of timely detection of and response to the rupture

- The pipeline supervisory control and data acquisition (SCADA) system did not have safety-related alarms established at values sufficient to alert the control room staff to the release at this location.
- Control room staff did not detect the abnormal conditions in regards to the release as they occurred. This resulted in a delayed shutdown of the pipeline.
- The pipeline controller restarted the Line 901 pipeline after the release occurred.
- The pipeline's leak detection system lacked instrumentation and associated calculations to monitor line pack (the total volume of liquid present in a pipeline section) along all portions of the pipeline when it was operating or shut down.
- Control room staff training lacked formalized and succinct requirements, including emergency shutdown and leak detection system functions such as

alarms.

The consequences of the spill were additionally aggravated by an oil spill response plan that did not identify the culvert near the release site as a spill pathway to the Pacific Ocean.

This report contains factual information and analysis regarding the events leading up to the release, information collected during PHMSA's failure investigation to date, and the technical analysis of that information known at the time of the completion of this report. PHMSA used this information to mandate remedial measures on Line 901, Line 903, and associated stations and tankage. PHMSA will also use the information to determine whether violations of the federal pipeline safety regulations occurred.

Final Report Methodology

PHMSA conducted relevant interviews, gathered and reviewed numerous historical documents and available records, and performed a thorough review of the Plains Control Room in Midland, TX. An ILI subject matter expert (SME) was hired to review the raw magnetic flux leakage (MFL) data and final vendor reports from the MFL surveys, and evaluated Plains actions as a result of their review of the vendor reports. PHMSA issued a CAO which in part instructed Plains to have the failed pipe examined by a PHMSA-approved metallurgical laboratory and to have a root cause failure analysis (RCFA) performed by a third party independent consultant.

The factual evidence reviewed includes: the Plains Integrity Management Plan (IMP), CP records, ILI reports, anomaly dig information, SCADA event and alarm logs, pressure and flow trends, procedures and reports obtained from the pipeline operator and PHMSA SMEs.

The arrangement of this report provides a general description of the pipeline system, the events that occurred on the day of the release, and acts or omissions of the operator that led to this failure and release of crude oil. Specific evidence is supplied and pertinent statements from each report are excerpted where appropriate.

Facility Background

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.

(1) 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.

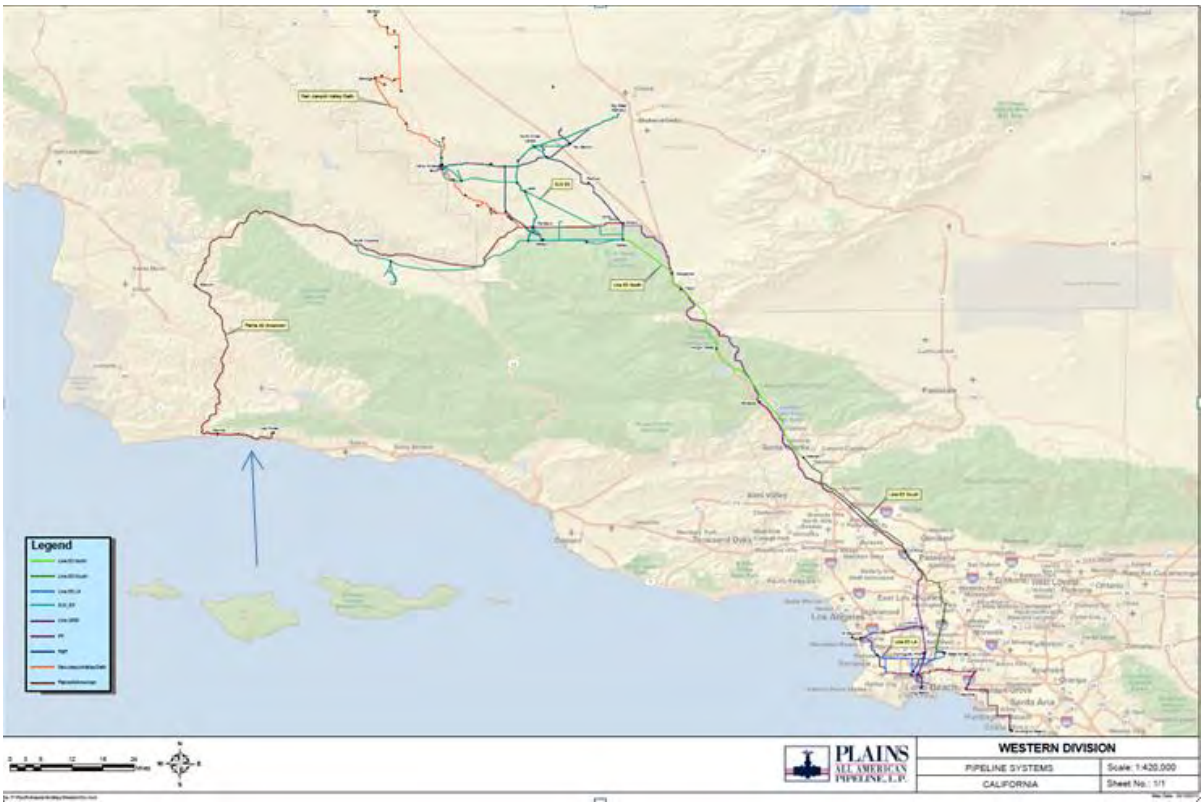


Figure 1. Map of Plains' Western Division Pipelines. The arrow points to the approximate release site on Line 901.

At Sisquoc Station, crude oil can be pumped to one of two locations: a nearby refinery via a 12-inch diameter pipeline operated by Phillips 66, or continue down Line 903 to Pentland Station. 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.

Prior to the May 19, 2015 release, there had been four small releases meeting PHMSA reportable criteria at pump stations on Lines 901 and 903. No releases were reported to PHMSA on the pipelines outside of pump stations prior to 2015. The operator reported maximum operating pressure (MOP) of Line 901 is 1,341 psig.

At the time of the spill, Plains All American Pipeline (PAAPL) operated Line 901 and Line 903 under a Federal Energy Regulatory Commission (FERC) certificate of economic regulatory jurisdiction that was issued in 1987. Plains Pipeline, LP, is a subsidiary of PAAPL. Based on the FERC filing, Lines 901 and 903 were classified as interstate pipelines, pursuant to 49 U.S.C. § 60101(7), as facilities used to transport hazardous liquid in interstate or foreign commerce, and as such, were regulated by PHMSA as interstate pipelines. Plains cancelled the FERC certificates for Lines 901 and 903 on February 12, 2016 and April 29, 2016,

respectively, stating that the transportation service was no longer available in interstate commerce. Line 903 from Gaviota to Sisquoc to Pentland Stations was purged with nitrogen in accordance with Amendment No. 2 to the CAO, and remains shut down between these stations. The Pentland to Emidio segment of Line 903 is active and operating intermittently at low pressures. This section of pipe between Pentland and Emidio is not directly connected to the Gaviota to Pentland segment and is used to transport crude product from breakout tanks in Pentland Station.

Events Immediately Prior to and During the Crude Oil Release

On the morning of May 19, 2015, Lines 901 and 903 were transporting crude oil with a flow rate setpoint of 1,240 bbl per hour (BPH) leaving the Las Flores Station, and the discharge pressure was approximately 575 psig. Pumps were operating at the Las Flores Station on Line 901 and Sisquoc Station on Line 903. A Plains instrumentation and electrical technician was dispatched that morning to disconnect and remove a motor from a non-operational pump at the Sisquoc Station. While the technician was performing his work, the operational pump (Pump 401) at the Sisquoc Station was shut down unintentionally (i.e., "uncommanded"). When Pump 401 on Line 903 stopped operating, the pressure in Line 901 increased. The pressure rose to a maximum of 696 psig at the Las Flores Station discharge. The controller shut down the pump at Las Flores Station and the pressure remained at 677 psig. Approximately four minutes later, the pump at Las Flores Station was restarted. At approximately 10:55 a.m. PDT, the flow rate at Las Flores Station climbed from zero to 2,042 BPH. Concurrently, the line pressure rose to a high of 721 psig, then dropped to 199 psig, and then slightly increased to approximately 210 psig until the Las Flores pump was shut down a second and final time. Generally, a sudden increase in flow rate accompanied by a decrease in pressure is indicative of a release. PHMSA has determined that Pump 401 going offline in an "uncommanded" manner on the morning of May 19, 2015, was an abnormal event, but that this in itself should not have caused Line 901 to rupture.

PHMSA performed a detailed review of the SCADA event and alarm logs, and pressure and flow records. The review indicated that there was information reported by the SCADA system that indicated a release had occurred by approximately 10:58 a.m., and an alarm was generated on low pressure. The alarm was not set at an appropriate value. The alarm also did not have a major priority/severity or safety-related alarm status. The controller did not recognize the information he received as indicative of an abnormal operation. Evidence indicates that the controller was focused on the events at Sisquoc Station (i.e., restarting the Sisquoc pump that had gone down once uncommanded, and a second time on high case temperature along with other duties).[iii]

Due to the Sisquoc Station maintenance activity resulting in an unplanned pump shutdown, the controller anticipated alarms would be activated from the pipeline leak monitoring (PLM) system. According to interviews and a review of the alarm log, the PLM inhibit was requested by the controller to the step-up shift supervisor between 11:15 and 11:22 a.m.[iv] The step-up shift supervisor then inhibited (shut off) the PLM system alarms.[v] Also, during this time, the controller started an investigation of the SCADA data in an attempt to understand the operational abnormalities that were occurring. After attempting to restart the Sisquoc pump twice, the controller shut down the pipeline. PHMSA requested the operator review the flow imbalance calculations and provide a time when the PLM system would have generated an alarm if not inhibited, and it was determined that alarms would have been generated

approximately two minutes before the controller shut down the pipeline.[vi]

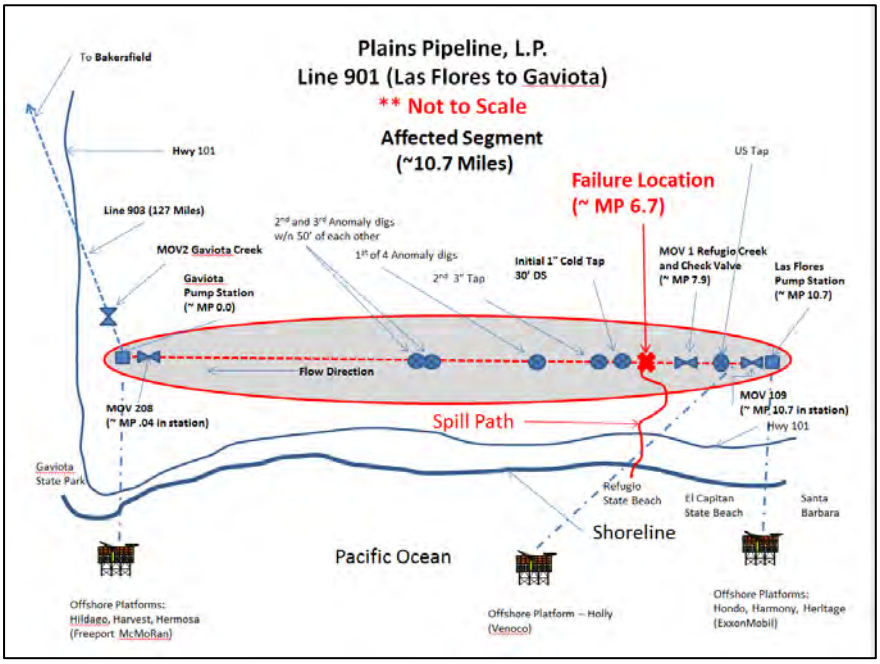


Figure 2. Schematic of Plains Pipeline, LP, Line 901 and spill path.

Plains' Field Response and National Response Center Notifications

The following is a timeline of Plains and emergency responder activities conducted immediately prior to locating the leak site:[vii]

- At 11:42 a.m. a call reporting a petroleum smell was received at Santa Barbara Fire Department (SBFD) Station 18. Engine 18 left the station to investigate the odor complaint near Refugio State Beach.
- At approximately 12:15 p.m., prior to a scheduled tabletop spill drill required by federal regulations 49 C.F.R. §194, the pre-drill meeting was completed and adjourned. A representative from the Santa Barbara Office of Emergency Management (SB-OEM) received a call from the SBFD reporting that there was oil on Refugio Beach. The SB-OEM representative and the Plains representatives left the spill drill and drove separately to Highway 101 at Refugio Beach.
- The Santa Barbara Dispatch notified the National Response Center (NRC #1116950) at 12:43 p.m. PDT of an unknown sheen in the ocean at Highway 101 and Refugio Beach.[viii]
- At approximately 12:55 p.m., the two Plains representatives arrived at the south side of Highway 101 where the SBFD personnel were. They noted oil in the ocean but could not determine the source of the oil. One of the Plains representatives told the assembled group that he did not think the oil was coming from Line 901 because the pipeline is located on the other side of Highway 101, and there would be oil flowing across Highway 101 if Line 901 was leaking.

- The Plains representatives drove to the company's pipeline right-of-way (ROW). At approximately 1:27 p.m., the Plains representatives located the leak site on the Plains ROW. They called the controller to report the leak and to tell the controller to leave Line 901 shut down and to close the Refugio gate valve. The Plains representatives used their cell phones to contact other Plains personnel, the landowner where the leak occurred, Plains' oil spill response contractors, and others. The Plains representatives noted that crude oil from the release site had entered a culvert that crosses under the Highway 101 and railroad tracks and discharges to Refugio Beach. The Plains representatives, along with Fire Department personnel, attempted to stop the flow of oil into the culvert. However, the culvert was too large to stop the flow with shovels, and sand bags were not readily available, so their immediate efforts were unsuccessful. At approximately 3:00 p.m., additional equipment and personnel arrived, the culvert was dammed and oil was prevented from entering the culvert.
- At 2:56 p.m., a representative from Plains called the NRC to report (NRC #1116972) the release of crude oil at 2:56 p.m. PDT. This report indicated that the release was at Latitude: 34° 27' 43" N; and Longitude: 120° 05' 24" W. This NRC report was made 89 minutes after the release site was found by Plains field personnel.[ix]

Figure 3. Spill location relative to Refugio Beach in Santa Barbara County, CA. Photo: John L. Wiley http://flickr.com/jw4pix

Federal pipeline safety regulations, (49 C.F.R. § 195.52), require that the NRC be notified at the earliest practicable moment following discovery of a release of a hazardous liquid, including "[a]ny failure that resulted in pollution of any stream, river, lake, reservoir, or other similar body of water that violated applicable water quality stands, caused a discoloration of the surface of the water or adjoining shoreline, or deposited a sludge or emulsion beneath the surface of the water or upon adjoining shorelines." On January 30, 2013, PHMSA issued an

Advisory Bulletin clarifying that this was to be interpreted as within one hour of discovery. Plains reported the rupture to the NRC approximately 89 minutes after discovery, thus notifying the NRC 29 minutes late.

The estimated costs reported by the operator as of December 23, 2015, were $142,931,884. This figure includes all costs the operator spent as a result of this release through the date reported, including commodity lost, the operator's property damage and repairs, operator's emergency response, environmental remediation, and estimated other costs spent including government agency costs and media relations expenses.[x]

PHMSA's Corrective Action Order

On May 21, 2015, PHMSA issued a CAO, CPF No. 5-2015-5011H, to Plains. The CAO required Plains to purge Line 901; review the pipeline's construction, operating, maintenance, and integrity management history; expedite the review of data from the May 5, 2015, ILI tool run; conduct metallurgical evaluation of the failed pipe; repair any integrity-threatening anomalies identified by the ILI survey; and conduct a root cause failure analysis. The CAO requires Plains to purge Line 901 and to keep Line 901 shut down until PHMSA approves the restart of the pipeline. Plains' Line 901 was purged and filled with an inert nitrogen gas on June 18, 2015.

On June 3, 2015, PHMSA issued Amendment No. 1 to the CAO. The amendment was issued to address preliminary findings from the early stages of PHMSA's investigation, and the possibility that the conditions on Line 901 also existed on Plains Line 903. The amendment to the CAO required Plains to conduct additional non-destructive testing of ILI anomalies on Lines 901 and 903; review the construction, operating, maintenance, integrity management, and ILI history of Line 903; and reduce the operating pressure of Line 903 to 80% of the highest pressure sustained for a continuous 8-hour period during the month before the May 19 failure. This pressure reduction was intended to enhance safety until all facets of the line's integrity could be evaluated.

On November 12, 2015, PHMSA issued Amendment No. 2 to the CAO. The amendment required Plains to empty and purge Line 903 between Gaviota and Pentland Stations and fill it with an inert gas. Line 903 was purged between Gaviota and Pentland Stations and filled with inert nitrogen. The complex purging operations began in December 2015, and were completed on April 18, 2016. Both Line 901 and the purged sections of Line 903 will remain shut down until all actions required by PHMSA's CAO and subsequent amendments have been completed. PHMSA may continue to issue additional amendments to the CAO as necessary.

Pipeline Alignment

Las Flores Station to Gaviota Station Line 901 Elevation Description

To fully understand the Line 901 release, it is vital to understand the elevation profile of Line 901 and Line 903 from the Las Flores Canyon to Pentland Station. Line 901 starts at the Las Flores Station at an elevation of approximately 180 feet. There are two large hills downstream of the originating pump station. The first hill has a peak elevation of approximately 740 feet and the second hill has an elevation of approximately 600 feet. The release occurred downstream of the second hill at an elevation of approximately 80 feet. Immediately downstream of the release point, the pipeline rises slightly and then runs relatively level approaching the Gaviota station. This fact is important because as soon as the pump at Las

Flores Pump Station was turned off the second time, the only crude oil that could be released was the height of oil in the pipeline above the release site and not the amount located between the two aforementioned hills.

Gaviota to Pentland Station Line 903 Elevation Description

Line 903 receives all of the crude oil delivered by Line 901. The line elevation at Gaviota is approximately 150 feet. The elevation at Sisquoc is approximately 880 feet. Downstream of Sisquoc, Line 903 rises to 2,420 feet and then to a height of approximately 2,750 feet and ultimately to an elevation of close to 3,000 feet before dropping into Pentland Station at an elevation of approximately 690 feet. Line 903 exhibits many of the same construction and operation conditions as Line 901 and was addressed by the amendments to the CAO. Pump 401 at Sisquoc Station has adequate capacity to push the oil up and over the downstream hills and into Pentland Station but only if it has full suction pressure and full flow coming into the pump. Because of the release, the pump could not push the oil over the downstream hills, and so the oil in the pump became hot and the pump shut down to prevent overheating.

Post-Incident Investigation Results

Metallurgical Evaluation of Failed Pipe

The failed pipe segment has been analyzed by third-party metallurgical experts, Det Norske Veritas (U.S.A.), Inc.'s (DNV-GL) in Dublin, OH. The failed pipe assessment and testing was witnessed by PHMSA, the California Department of Fish and Wildlife, and the U.S. Department of Justice.

Figure 4. The failed pipe and surrounding insulation and coating.

Figure 5. Pipe External Surface at the Line 901 failure site after cleaning.

DNV-GL's draft report was completed and disseminated to Plains and PHMSA on August 6, 2015. The draft report was reviewed by PHMSA engineers, and a number of comments and clarification requests were made. DNV-GL reviewed the comments and revised the report. The Final Report was issued on September 18, 2015.

The Final Report provides a summary of findings, including the following excerpt:

"The results of the metallurgical analysis indicate that the leak occurred at an area of external corrosion that ultimately failed in ductile overload under the imposed operating pressure. The morphology of the external corrosion observed on the pipe section is consistent with corrosion under insulation facilitated by wet-dry cycling."[xi]

In-Line Inspection Survey Review

Plains conducted ILI surveys on Line 901 (10.7 miles in length) to assess the integrity of the pipeline in accordance with PHMSA regulations in 2007, 2012, and 2015. According to 49 C.F.R. § 195.452(j)(3), the pipeline is required to be surveyed at intervals commensurate with the pipeline's risk of integrity threats, but at least every 5 years. Plains changed Line 901 from a 5-year assessment cycle to a 3-year assessment cycle after the 2012 ILI survey.

The data collected during these surveys must be fully evaluated within 180 days of the ILI, and an operator must take action upon discovery of any "immediate repair conditions" as defined in 49 C.F.R. § 195.452(h) unless the operator can demonstrate that the 180-day period is impracticable.

The most recent ILI survey for Line 901 was completed on May 6, 2015. The 2015 ILI survey data for the first 2 miles of Line 901, as measured from the Las Flores Station, was found to be incomplete and not useable for ILI analysis. For the rest of the ILI survey, the correlation digs, which are used to gauge survey data accuracy in the ILI vendor's preliminary report, had not been finished at the time of the May 19, 2015 failure.

PHMSA's independent third-party ILI SME also performed an analysis of the data from past ILI surveys of Line 901. Preliminary data from the results of each of the ILI surveys are summarized below and show a growing number of corrosion anomalies on Line 901.

Number of Anomalies

Metal loss	June 19, 2007	July 3, 2012	May 6, 2015
Greater than 80%	0	0	2
60-79%	2	5	12
40-59%	12	54	80

The May 6, 2015 ILI survey data and subsequent analysis by the ILI vendor predicted external corrosion at the failure site with an area of 5.38 inches by 5.45 inches, and a maximum depth of 47% of the original pipe wall thickness. After the failure, the DNV-GL metallurgical investigators physically measured external corrosion at the failure site to have a maximum depth of 89%.[xii] The dimensions of the corrosion feature were 12.1 inches axially by 7.4 inches in circumference. The maximum depth, as measured using laser scan data, was 0.318 inches or 89% of the measured wall thickness (0.359 inches).

The ILI summary report prepared by PHMSA's SME also examined the "as-called" (ILI-predicted) versus as-found (field measured) lengths, widths and area for the excavated anomalies on Line 901. The report demonstrates that the lengths and widths of the anomalies were under-called (underestimated) in many cases, however many were also over-called. Plains submitted little documentation concerning their analysis of how the field measured anomalies compared to the ILI vendor analysis. Furthermore, Plains did not provide documentation showing that discrepancies between the originally reported anomaly sizes predicted by the ILI vendor and Plain's actual field-measured sizing of the corrosion anomalies were subsequently discussed with the ILI vendor, as required by Plains' IMP.[xiii]

Cathodic Protection Findings

According to 49 C.F.R. § 195.563, CP is required under the federal Pipeline Safety Regulations to prevent external corrosion of buried pipelines. Historical CP records for line 901 have been reviewed and reveal protection levels that typically are sufficient to protect non-insulated, coated steel pipe. Line 901 and Line 903, however, are insulated. An increasing frequency and extent of corrosion anomalies were noted on both Lines 901 and 903 in ILI survey results, anomaly excavations, and repairs. PHMSA inspectors noted moisture entrained in the insulation at four excavations performed by Plains on Line 901 after the May 19 spill and prior to the PHMSA-mandated purging of the pipelines.

Spill Volume Estimate from Plains' Third-Party Consultant

Plains initially estimated the volume of spilled crude oil to be approximately 2,400 bbl, of which 500 bbl was estimated to have reached the ocean. On August 4, 2015, Plains reported to the Unified Command that the 2,400 bbl release estimate was still accurate. However, after Plains completed the PHMSA-mandated purge, the company's calculations indicated that up to 3,400 bbl had possibly been released from the pipeline. Plains notified the Unified Command

that RPS Knowledge Reservoir (RPS), a third-party investigator hired by Plains, was still trying to reconcile the difference.

On November 24, 2015, Plains informed PHMSA that RPS had completed their analysis regarding the release volume and produced a report of findings. RPS used the OLGA simulation software tool to model the behavioral dynamics of the pipeline prior to, during, and immediately after the May 19, 2015 leak. The report concluded that the discharge leak volume was 2,934 bbl. The RPS report was dated November 11, 2015. Plains has reported 1,100 bbl of crude oil have been recovered.

Investigation Findings and Conclusions

Line 901 pipeline ruptured at approximately 56% of the MOP. Although the operational events that occurred on the morning of the release were abnormal, this should not have caused the release if the pipeline's integrity had been maintained to federal standards.

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.

PHMSA's investigation identified numerous contributory causes of the rupture. The contributory causes can be grouped into three categories: 1) ineffective protection against external corrosion of the pipeline; 2) failure by Plains to detect and mitigate the corrosion;, and 3) lack of timely detection of the rupture. Below is a summary of the key contributory causes:

Contributory Causes

1) Ineffective protection against external corrosion of the pipeline

   - Plains' CP system was ineffective in protecting thermally insulated underground pipeline systems from external corrosion. Industry practices recognize that an impressed current system like the one utilized on Line 901 cannot protect an insulated steel pipeline should the coating (tape wrap over insulation) become compromised. The external coating in the area of the rupture had allowed moisture to enter the insulation adjacent to the steel pipe.[xiv] Corrosion under insulation (CUI) cannot be prevented on insulated lines where the coating system has been compromised.[xv]

2) Failure by Plains to detect and mitigate external corrosion

   - Plains did not identify CUI as a risk-driving threat in their federally-mandated integrity management program (IMP).

- Plains' did not fully implement their IMP.
    - Plains did not perform suitable analysis of the field measurements of the excavated corrosion anomalies that occurred after ILI surveys were completed in 2007 and 2012.
    - The data reported by the ILI vendor were inconsistent (and did not meet the published accuracy of the ILI tools of +/- 10%, 80% of the time for depth) when compared to the results of the field-measured corrosion anomalies.
    - Plains' as-found field measurements of corrosion anomalies were inconsistent with the as-called vendor-provided ILI data and analytical reports. ILI surveys conducted in 2007 and 2012 revealed inconsistencies in the character of the anomalies. In both of these cases, Plains did not consult the ILI vendor to help resolve the inconsistency.
    - Plains failed to follow written procedures directing the IMP group to perform appropriate statistical analysis after the anomaly dig reports were received from the field, and to discuss any inconsistencies with the ILI vendor.[xvi]
        - Plains' Pipeline Integrity group created a unity plot for depth after the 2012 ILI survey and anomaly digs. There is no documentation detailing what was done with the information from the unity plot.
    - Plains incorrectly added the over-called anomalies in the close-out reports.
        - The close-out reports should have only reported the anomalies that were within the reported accuracy of the ILI tool. The reported tool accuracy is +/- 10 %, 80 % of the time. Adding the overcalled anomalies outside of the tool accuracy skews the data.
- Plains' Pipeline Integrity group was historically focused on pitting corrosion under "shrink sleeves" at the pipeline girth welds (circumferential welds to join pipe segments).
    - The release location was within 6 feet of a corrosion anomaly that was exposed and repaired after the 2012 ILI survey. There was evidence of corrosion and degraded coating systems between the 2012 repair site and the 2015 rupture site.
    - The anomaly that ruptured was called out by the ILI tool at 45% depth in 2012. Plains' IMP specified adding 10% to all anomalies (55% depth in this case) then "growing them" to predicted failure using an anticipated corrosion growth rate. This analysis would provide a predicted failure time. Plains did not excavate the anomaly that failed.

3) Lack of timely detection of and response to the rupture

- The controller did not have information communicated from the SCADA system in such a manner to be successful in detecting abnormal operations. The pipeline SCADA system did not have safety-related alarms on low pressure configured at the

correct value or priority to alert the control room staff of the rupture. When this alarm was provided to the controller, the discharge pressure at Las Flores was 199 psig but, within a minute, pressure elevated above 210 psig, the alarm status cleared, and the discharge pressure remained above 200 psig (approximately 210-211 psig) until the pipeline was purged. The pipeline was still leaking when the discharge pressure at Las Flores was above 200 psig, and continued to do so without additional alarm indications. When the pipeline was down, isolated but still leaking, the minimum pipeline discharge pressure at Las Flores remained at 210-211 psig. The low discharge pressure alarm setpoint value was not set properly as it should have been above 211 psig. This type of alarm should be identified as a high priority safety related alarm. While the controllers and shift supervisors can access historical trend data or continue to monitor a given pressure or flow, when the pipeline was ultimately shut down at 11:30 a.m., neither the controller nor step-up shift supervisor detected any drop of pressure at the specific failure location that would indicate that oil was being released.

- Neither the pipeline controller nor step-up shift supervisor detected the initial abnormal conditions as the release occurred. There was an indication of decreased pressure and increased flow between 10:53 and 10:58 a.m., which is consistent with a pipeline release. This resulted in a delayed shutdown of the pipeline. Adequate alarm setpoint values with correct priorities are essential to controller and shift supervisor recognition of abnormal operations, especially when many pipeline systems are operated from the same console.

- The pipeline controller restarted Line 901 after the release occurred.
- The pipeline leak detection system lacked instrumentation and associated calculations to monitor line pack.
    - The function of the PLM system was a simple line balance calculation based on flow meter values without line pack considerations. The PLM relies on comparing "meter in – meter out" calculations over time. This type of leak detection system without the use of safety-related, high-priority, low-pressure alarms does not provide the controller or shift supervisors with adequate information when the pipeline is down.
    - When the pipeline is not running, even if only due to scheduling and not required maintenance activities, flows will be close to zero and the imbalance calculation will provide little if any value as currently configured. Leak detection on a down pipeline requires a robust system of planned and accurate high-priority alarm types and alarm setpoint values in order for response to occur on critical low pressures.
    - The leak detection system for Lines 901 and 903 consists of two leak detection segments. Additional instrumentation such as pressure and temperature transmitters located at Refugio Gate and Cuyama valve settings (both transmitter types on each side of the valves) would allow additional information about the operating status of the pipeline to be presented and pack calculations pursued.
    - Plains utilizes the SimSuite application for other pipelines in the control

center. This application does allow for pack calculations to be utilized in the leak detection system. According to information obtained during meetings with Plains hydraulic specialists, Lines 901 and 903 were pipeline systems with a low to medium priority defined for future modeling efforts compared to other assets in the Plains operations. The approach utilized by Plains for prioritizing which systems should be modeled first did not appear to take into account all appropriate consequence-based asset impacts (such as culverts providing a pathway to the ocean) associated with these two systems. Existing instrumentation and the need for added instrumentation would factor into this prioritization decision.

- Control room staff training lacked formalized and succinct requirements, including emergency shutdown and leak detection system functions such as alarms.
    - Interviews determined that the step-up shift supervisor and shift supervisor training lacked formalized and succinct requirements, including that for leak detection system functions such as "inhibit" options. The interviews determined that different shift supervisors performed PLM inhibit functions without contacting the console supervisor first as required by procedure.
    - Step-up and shift supervisor responsibilities include emergency shutdown of any pipeline. However, training does not cover a means by which to accomplish this for all relevant pipelines. A general emergency shutdown provision has not been programed for supervisory use on all systems.
- The oil spill response plan required by 49 C.F.R. §194 did not account for a culvert near the release site that traversed the Pacific Coast Highway and Amtrak railroad tracks. This culvert provided a quick flow path between the pipeline ROW and the Pacific Ocean, thereby allowing crude oil to flow easily towards Refugio State Beach and the ocean. The response plan did not have a response strategy that considered the presence of the culverts.

PHMSA Post-Incident Action Chronology

Following the May 19, 2015 Plains Pipeline, LP, Line 901 rupture in Santa Barbara County, CA, PHMSA took the following actions:

- On May 19, 2015, PHMSA deployed inspectors to investigate the Plains Pipeline LP Line 901 pipeline failure in Santa Barbara County, CA. PHMSA also provided information updates to the Unified Command (UC), US Coast Guard, the Federal on Scene Coordinator (FOSC), State Fish and Wildlife, and other agencies on site.
- On May 21, 2015:
    - PHMSA issued a Corrective Action Order (CAO), CPF No. 5-2015-5011H, to Plains Pipeline LP ordering it to suspend operations and to specific safety actions to further protect the public, property, and the environment from potential hazards associated with the recent failure. PHMSA staff reviewed the CAO with the operator and briefed the California State Attorney on the CAO and provided an overview of PHMSA's regulations.
    - PHMSA sent an inspector to Plains' control room in Midland, Texas to collect operational data and interview the control room operators on duty at the time of the incident and their supervisors. The inspector gathered any pertinent logs and information, including electronic copies of relevant data from the Supervisory Control and Data Acquisition (SCADA) system.
    - PHMSA staff worked with the operator to review their plan to expose the pipe and to cold tap it to ensure there was no pressure or crude left in the line at a low spot immediately downstream of the release point. The plan was signed off by the UC at approximately 5 pm PDT.
- On May 22, 2015:
    - PHMSA staff met with representatives from the Assistant U.S. Attorney, DOT Inspector General, EPA Criminal Investigation Division, California Attorney General, and others to brief them on PHMSA's process for securing and transporting the failed pipe to a metallurgical lab for evaluation.
    - PHMSA staff remained on the scene as the operator exposed, tapped, removed any remaining product, and excavated the pipeline downstream of the release site.
- On May 25, 2015:
    - PHMSA issued an approval letter for Plains to excavate, remove and secure the failed joint of pipe under the supervision of two DNV metallurgists (third party contractor) but requested that the coating and insulation not be touched until the failed pipe has been removed because the DNV personnel were interested in in gathering available samples there as well.
    - A PHMSA inspector returned to Midland, TX to interview the controller and the Operations Control Center supervisor and to obtain any handwritten logs created by the controller on the morning of the release.
- On May 28, 2015:
    - A PHMSA investigator was on site when affected pipeline was removed, crated, and transported to secure location for metallurgical evaluation. PHMSA retained a third-party ILI expert to examine the 2012 and 2015 ILI runs. DNV personnel took soil and insulation samples.
- On June 3, 2015, PHMSA amended the CAO to address preliminary findings from the early stages of the investigation (Amendment No. 1). The amended CAO mandated

additional safety requirements on Line 901 and expanded the scope of the CAO to include the 128-mile long Line 903, which is located downstream of Line 901. The amendment reduced the operating pressure of the Lone 903 by 80% of the highest 8 hour continuous pressure between April 19, 2015 and May 19, 2015. On May 30, 2015, Plains voluntarily shutdown Line 903.

- On June 18, 2015, PHMSA staff monitored the Line 901 purge to ensure safety during the purging process. Plains completed the purge and injected inert gas in Line 901.
- On September 18, 2015, PHMSA received the DNV Final Mechanical and Metallurgical Report. PHMSA staff reviewed the document and provided comments.
- On November 12, 2015, PHMSA issued Amendment No. 2 to the CAO, which ordered Plains to purge and shutdown Line 903 from Gaviota to Pentland.
- On December 1, 2015, PHMSA staff monitored Plains moving Freeport McMoRan crude oil from their offshore platforms into Line 903 from Gaviota Station to Sisquoc Station. Movement of the Freeport McMoRan oil was completed on December 10, 2015.
- On December 4, 2015, PHMSA staff received the DNV Root Cause Failure Analysis Report. PHMSA reviewed and commented on the report.
- On December 14, 2015, PHMSA staff monitored the purge process on Line 903 from Gaviota Station to Sisquoc Station. The purge was completed on December 18, 2015 and the line was filled with inert gas.
- On February 17, 2016, PHMSA issued a Preliminary Factual Final Report.
- On April 2, 2016, PHMSA staff monitored the Line 903 Sisquoc to Pentland portion purge that was completed on April 18, 2016. Line 901 and 903 are shutdown, except for the Pentland to Emidio section of Line 903, which is not connected to 903 any longer.

APPENDICES

A. Investigation Summary Detail
B. Supervisory Control and Data Acquisition (SCADA) Log Excerpts
C. Pipeline Leak Monitoring Details
D. Excerpts and Discussion of Plains Integrity Management Plan (IMP) Requirements
E. Corrosion Control and Pipeline Conditions
F. Industry Standards and General Requirements for In-Line Inspection
G. In-Line Inspection Report
H. PHMSA's Independent Analysis of In-Line Inspection Data
I. Maps and Photographs
J. National Response Center Report #1
K. National Response Center Report #2
L. Form PHMSA F 7000.1: Accident Report for Hazardous Liquid Pipeline Systems
M. Det Norske Veritas (U.S.A.), Inc. (DNV GL): Line 901 Release (5/19/15) Mechanical and Metallurgical Testing
N. Det Norske Veritas (U.S.A.), Inc. (DNV GL): Line 901 Release (5/19/15) Technical Root Cause Analysis
O. NACE International: Effectiveness of Cathodic Protection on Thermally Insulated Underground Metallic Structures

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[i] According to the *FRACTURE CONTROL TECHNOLOGY FOR NATURAL GAS PIPELINES CIRCA 2001* (the PRCI report superseding NG-18 Report 208): "The distinction between leak and rupture for the pipeline community is based on the size and configuration of the breach, not how it develops." Based on these calculations and visual observations, the length of the feature is consistent with a leak, arresting within the corrosion feature, and did not propagate outside of the feature into nominal wall-thickness pipe. According to the instructions for completing PHMSA Accident Form 7000-1, this type of accident would be classified as a rupture since PHMSA defines a "rupture" as a "loss of containment that immediate impairs the operation of the pipeline".

[ii] The remedial action plan requires: a) investigation and remediation of anomalies on Line 901 (including anomalies requiring repair per 49 C.F.R. § 195.452(h) and similar anomalies); b) analysis of field measurements taken from anomaly investigations; c) re-grade of previous in-line inspection (ILI) data from 2012 and 2015 ILI surveys using an expanded set of interaction criteria; d) additional integrity assessments using a circumferential magnetic flux leakage (MFL-C) ILI tool and integration of MFL-C ILI data with previous ILI survey results; e) investigation and remediation of anomalies that are identified in the MFL-C tool run (if any); f) based on information collected from remedial work plan and root cause analysis report released by Det Norske Veritas (U.S.A.), Inc., improving the integrity management program; and g) integrity studies to reduce spill volumes, including an emergency flow restriction device evaluation and a surge study. Completion of the remedial work plan is required prior to the PHMSA Western Region Director approving a restart plan and return to service for Line 901.

[iii] High case temperature refers to the oil temperature inside the pump cavity. The case holds the pump impeller

where oil passes through. This was a centrifugal pump that continues spinning whether there is product in the pump or not. When the rupture occurred, there was not enough pressure or flow rate to allow the pump to continue pumping the oil over the hills and into Pentland Station. Therefore, the oil that was in the pump remained in place and as the pump continued to spin, and temperature was reported to the SCADA system. If the pump reaches the high temperature setpoint, the pump shuts itself off to protect itself from burning up.

[iv] The PCR utilizes two shift supervisors to cover the entire set of 22 consoles. The California Console is handled by shift supervisor B. The shift supervisor B position at the time of the failure was filled by a step-up shift supervisor. A step-up shift supervisor is a controller who is currently qualified on a specific console in the PCR and has received some informal training by working on shift with other shift supervisors. Step-up shift supervisors are used to cover the shift supervisor positions when additional personnel are needed due to illness, vacation, training, etc. Plains has indicated that two step-up shift supervisors are not allowed to be on duty at the same time so one shift supervisor is paired with a step-up shift supervisor when additional personnel is needed.

[v] PLM is the SCADA vendor software tool that serves as the leak detection system for PCR.

[vi] *See* Appendix B.

[vii] SCADA Data/Plains Control Room time is local to the Central Time Zone. A two-hour time difference separates Central Time from Pacific Time, with Central Time falling two hours ahead. The release occurred in the Pacific Time Zone which is two (2) hours earlier. All times in this report have been adjusted to Pacific Time.

[viii] *See* Appendix J.

[ix] *See* Appendix K.

[x] *See* Appendix L.

[xi] *See* Appendix M.

[xii] PHMSA has access to this data through a view-only web portal.

[xiii] *See* Appendix G.

[xiv] The inability of an impressed cathodic protection system to protect insulated pipelines was most recently reaffirmed in the National Association of Corrosion Engineers (NACE) Publication 10A392 (2006 Edition) – "Effectiveness of Cathodic Protection (CP) on Thermally Insulated Underground Metallic Structures."

[xv] *See* NACE Report at Appendix O, Background section stating that "[o] n most thermally insulated oil and gas transmission pipelines installed prior to 1980 to 1981, a shop mold-formed thermal insulation was placed directly over the bare steel pipe, with an outer jacket applied to moisture-proof the system. At the field joint, preformed insulation half shells were applied over the joint area to fit between the ends of the shop-applied insulation. After the insulation was fitted, a heat shrink sleeve or a tape wrap was applied over the insulation. When the integrity of the outer moisture barrier was compromised, the space, gap, or void between the edges of the preformed half shells and the shop-applied insulation allowed oxygenated water to diffuse to the bare steel beneath. Damage to the outer moisture barrier has also occurred remote from the joint, allowing oxygenated ground water ingress.

"Thermally insulated pipelines have experienced relatively aggressive corrosion, with some failures occurring within three years of service, although acceptable industry standards of CP had been applied and maintained shortly after line construction. The most predominant failures have been those occurring at joints; however, moisture has migrated along the pipeline steel surface to create electrochemical corrosion cells remote from the field joint, culminating in extensive replacements of substantial lengths of line. An article titled 'Corrosion of Underground Insulated Pipelines' supports this committee's conclusions that sufficient CP current from an external source may not reach the insulated metallic surface in sufficient quantity to establish adequate corrosion control."

[xvi] *See* Appendix D.