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

ENVIRONMENTAL DEFENSE CENTER, a California non-profit corporation; GET OIL OUT!, a California non-profit corporation; SANTA BARBARA COUNTY ACTION NETWORK, a California non-profit corporation; SIERRA CLUB, a national non-profit corporation; and SANTA BARBARA CHANNELKEEPER, a California non-profit corporation, Petitioners and Plaintiffs, vs. CALIFORNIA DEPARTMENT OF FORESTRY AND FIRE PROTECTION, by and through the OFFICE OF THE STATE FIRE MARSHAL, an agency of the State of California; DANIEL BERLANT, in his official capacity as State Fire Marshal; and DOES 1 to 10, inclusive, Respondents and Defendants, and SABLE OFFSHORE CORP., a Delaware corporation; and PACIFIC PIPELINE COMPANY, a Delaware Corporation, Real Parties in Interest.	Case No.: **VERIFIED PETITION FOR WRIT OF MANDATE AND COMPLAINT FOR DECLARATORY AND INJUNCTIVE RELIEF**

Petitioners and Plaintiffs ENVIRONMENTAL DEFENSE CENTER, GET OIL OUT!, SANTA BARBARA COUNTY ACTION NETWORK, SIERRA CLUB, and SANTA BARBARA CHANNELKEEPER (collectively, "Petitioners") respectfully petition this Court for a writ of mandate pursuant to Code of Civil Procedure sections 1085 and 1094.5 and seek declaratory and injunctive relief against Respondents and Defendants CALIFORNIA DEPARTMENT OF FORESTRY AND FIRE PROTECTION, by and through its component agency OFFICE OF THE STATE FIRE MARSHAL, and State Fire Marshal DANIEL BERLANT (collectively, "Respondents"), and allege as follows:

INTRODUCTION

1. This case arises from the efforts of Sable Offshore Corp. and its wholly-owned subsidiary Pacific Pipeline Company (together, "Sable") to restart the Las Flores Pipeline System — a defective pipeline system that ruptured in 2015, causing one of the worst oil disasters in California history.

2. On May 19, 2015, pipeline CA-324, a segment of the Las Flores Pipeline System, ruptured at Refugio State Beach Park, spilling more than 120,000 gallons of heavy crude oil into the surrounding environment. The spill was catastrophic. It closed public parks and beaches, killed and injured wildlife, shut down fisheries, and sickened nearby residents with chemical pneumonia.

3. Upon investigation, the Pipeline Hazardous Materials Safety Administration (PHMSA) determined that the rupture was a result of "progressive external corrosion," and that the pipeline's cathodic protection system — intended to prevent such corrosion — had failed. Concerningly, PHMSA ultimately determined that, by flaw of design, cathodic protection is ineffective on the Las Flores Pipeline System, leaving it vulnerable to pervasive corrosion.

4. Because of the Las Flores Pipeline System's dangerous design defects, few suspected that an operator would attempt to bring it back online. In fact, since the pipeline system was idled in 2015, a series of proposals were floated to replace or bypass the system, ostensibly due to the pipelines' obvious risks to public safety.

5. Now, however, Sable — a new, speculative company — is attempting to restart, rather than replace, the defective pipeline system, disregarding a litany of environmental and safety concerns as it rushes to resume drilling off the Gaviota Coast.

6. Because of the Las Flores Pipeline System's extensive corrosion issues, in order to restart it, Sable must obtain waivers from the Office of the State Fire Marshal (OSFM) that excuse it from complying with certain regulatory requirements. Specifically, Sable must obtain State Waivers "for the limited effectiveness of cathodic protection" on CA-324 and CA-325, the two pipeline segments that comprise the Las Flores Pipeline System. Sable submitted applications for the two aforementioned State Waivers in April 2024.

7. Importantly, Sable's proposal to operate the Las Flores Pipeline System without effective cathodic protection represents a substantial departure from the project that was initially reviewed and approved. When first proposed in the 1980's, the pipeline system was expressly proposed as one that would be protected, in its entirety, by cathodic protection. Hence, environmental review of the project, conducted *forty* years ago, was largely premised on effective cathodic protection; indeed, in considering the project's potential impacts, the Environmental Impact Report (EIR) expressly relied on cathodic protection as a design specification that would be "very effective" in preventing an oil spill, and it assumed the same in evaluating potential impacts.

8. The risks of operating the Las Flores Pipeline System without effective cathodic protection have never been fully evaluated. However, an analysis prepared by OSFM found that operating buried pipelines without cathodic protection can increase the risk of a spill by as much as *five times*. And a separate analysis, discussed below, found that operating this particular pipeline system without effective cathodic protection could result in a spill *every year*, and a major rupture *every four*.

9. We have already seen first-hand the devastation that these pipelines can wreak on coastal resources. But the 120-mile long pipeline system also threatens major sources of water supply, renowned parks and ecological reserves, and a number of endangered and special-status species. Perhaps most concerning, however, is that it runs directly under a populated suburban neighborhood in Buellton, California, complete with schools, parks, and dozens of residential homes.

10. In light of the obvious threat to public health and safety posed by these defective pipelines, community organizations sent multiple requests to OSFM for increased transparency and public engagement as it considered Sable's State Waiver applications. Petitioners called on OSFM to hold a public hearing on the applications, as required by law. They also pointed out that operating the

Las Flores Pipeline System without effective cathodic protection was neither anticipated nor reviewed in the original EIR for the project, necessitating that OSFM conduct further environmental review pursuant to the California Environmental Quality Act (CEQA).

11. Community outcry was echoed by thirteen state legislators, who sent a letter of their own to OSFM calling for environmental review of Sable's State Waiver applications and a transparent public process. The letter stated that the legislators "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. . . . [O]ne 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."

12. Acknowledging "the public's considerable interest in the restart of these pipelines," OSFM committed to holding a "public meeting" — not a hearing, as required — *before* making a determination on Sable's State Waiver applications.

13. Then, on December 17, 2024, without having held any sort of "public meeting," OSFM approved the State Waiver applications. OSFM did not offer any cognizable public process in advance of its decision or even release key documents (like the applications themselves); did not conduct environmental review of the State Waiver applications; and did not provide any supporting analysis or justification for its decision to grant the Waivers. In doing so, OSFM entirely disregarded applicable pipeline safety laws, bedrock environmental laws, and its own previous commitments to state legislators and the public.

14. Given the unprecedented nature of these Waivers, and the critical resources that this 120-mile-long pipeline system can impact, the need for public comment, independent expert scrutiny, and environmental review was especially critical here. Yet OSFM pushed the Waivers through behind closed doors, reneging even on its minimal commitment to first have a "public meeting" on the issue.

15. Without the benefit of public review, the Waivers that OSFM approved have a number of glaring deficiencies, and they ultimately fail to ensure that the pipelines will be "as safe or safer" than if they had effective cathodic protection — the standard under which OSFM reviewed Sable's applications. Those deficiencies are discussed at length below and in the attached expert reports.

16. Most notably, the logic underpinning the Waivers is fundamentally flawed. Instead of *proactively* preventing corrosion in the first place, the Waivers condition operation of the pipelines on a number of *reactive* measures — namely, conducting more frequent inspections to check for corrosion — that leave room for operator error. The management program contemplated by the Waivers, which *allows* the progressive corrosion of the Las Flores Pipeline System to continue, cannot, by any measure, be considered as safe as preventing corrosion in the first place.

17. Moreover, the Waivers are largely (and naively) premised on the hope that Sable will do a better job than the previous operator at detecting and remediating corrosion. But there is little reason to suspect that will be the case. The in-line inspection tools used to detect corrosion have proven to be inaccurate and unreliable when measuring corrosion on the Las Flores Pipeline System; in fact, the failure of such tools was a contributing factor of the Refugio Oil Spill. And Sable — a new, speculative company that has never actually operated an oil and gas pipeline — has done little to assure that it can or will comply with the Waivers' intensive management program.

18. Restarting the Las Flores Pipeline System in the manner envisioned by OSFM would not only invite another oil disaster on the Central Coast, but all but ensure it. The decision to grant the Waivers represents a grave dereliction of OSFM's duty to ensure the safety of hazardous liquid pipelines, made worse by the fact that OSFM provided no public process or justification for its decisions.

19. This Petition challenges Respondents' discretionary approval of the State Waivers on the grounds that Respondents (1) failed to comply with mandatory procedures outlined in state and federal pipeline safety laws, (2) failed to comply with CEQA's environmental review process, and (3) prejudicially abused its discretion in issuing the Waivers.

JURISDICTION AND VENUE

20. Petitioners hereby incorporate by reference each and every allegation set forth above.

21. This Court has jurisdiction over Petitioners' claims against Respondents under sections 1060, 1085, and 1094.5 of the Code of Civil Procedure, and Article VI, section 10 of the California Constitution.

22. This case is properly classified as an unlimited civil case, and therefore within the

jurisdiction of this court, because it is not one of the types of cases listed as limited civil cases in section 85 or 86 of the Code of Civil Procedure.

23. Venue for this action properly lies in the Superior Court of the State of California in and for Santa Barbara County, as the Las Flores Pipeline System is located in Santa Barbara County and the causes of action arose therein.

24. Petitioners have performed all conditions precedent to filing this action and have exhausted all available remedies to the extent required by law. Petitioners do not have a plain, speedy, or adequate remedy at law but depend on the Court granting the relief requested herein to require Respondents to satisfy their obligations under state and federal law.

PARTIES

25. Petitioner and Plaintiff ENVIRONMENTAL DEFENSE CENTER (EDC) is a non-profit, public interest environmental law firm that defends nature and advances environmental justice on California's Central Coast through advocacy and legal action. EDC has members who live, visit, work, and recreate in and around the area that would be affected by the restart of the Las Flores Pipeline System under the State Waivers. EDC's members are interested in protecting resources along the 120-mile long pipeline route — including coastal resources; rivers, creeks, and wetlands; special-status species; and abundant recreational opportunities — from the risks of renewed oil and gas production. Members of EDC are also interested in preserving the environmental integrity of sensitive areas along the pipeline route that would be exposed to the risk of another oil spill, as well as continuous excavations required by the Waivers' management program. EDC, by and through its counsel, has submitted written comments to OSFM that detail its concerns with respect to the State Waivers. As such, EDC is beneficially interested in the outcome of this proceeding and in OSFM's performance of its legal duties.

26. Petitioner and Plaintiff SANTA BARBARA COUNTY ACTION NETWORK (SBCAN) is a nonprofit grassroots organization that works to promote social and economic justice, preserve environmental and agricultural resources, and create sustainable communities within Santa Barbara County, California. SBCAN advocates a holistic approach to community planning that integrates housing, open space, and transportation to meet the needs of all members of the community and future

generations. SBCAN works in cooperation with a broad range of progressive activists and organizations to bridge the gap between environmental and social justice issues and ensure that all members of the community share a voice in its future. SBCAN has members who live, visit, work, and recreate in and around the area that would be affected by the restart of the Las Flores Pipeline System under the State Waivers. SBCAN's members are interested in protecting resources along the 120-mile long pipeline route — including coastal resources; rivers, creeks, and wetlands; special-status species; and abundant recreational opportunities — from the risks of renewed oil and gas production. Members of SBCAN are also interested in preserving the environmental integrity of sensitive areas along the pipeline route that would be exposed to the risk of another oil spill, as well as continuous excavations required by the Waivers' management program. SBCAN, by and through its counsel, has submitted written comments to OSFM that detail its concerns with respect to the State Waivers. As such, SBCAN is beneficially interested in the outcome of this proceeding and in OSFM's performance of its legal duties.

27. Petitioner and Plaintiff GET OIL OUT! (GOO!) is a non-profit organization that 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. GOO! has members who live, visit, work, and recreate in and around the area that would be affected by the restart of the Las Flores Pipeline System under the State Waivers. GOO!'s members are interested in protecting resources along the 120-mile long pipeline route — including coastal resources; rivers, creeks, and wetlands; special-status species; and abundant recreational opportunities — from the risks of renewed oil and gas production. Members of GOO! are also interested in preserving the environmental integrity of sensitive areas along the pipeline route that would be exposed to the risk of another oil spill, as well as continuous excavations required by the Waivers' management program. GOO!, by and through its counsel, has submitted written comments to OSFM that detail its concerns with respect to the State Waivers. As such, GOO! is beneficially interested in the outcome of this proceeding and in OSFM's performance of its legal duties.

28. Petitioner and Plaintiff SIERRA CLUB, a national nonprofit organization with thousands of members in California, is dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and encouraging humanity to protect and restore the quality of the natural and human

environment; and to using all lawful means to carry out these objectives. Sierra Club has members who live, visit, work, and recreate in and around the area that would be affected by the restart of the Las Flores Pipeline System under the State Waivers. Sierra Club's members are interested in protecting resources along the 120-mile long pipeline route — including coastal resources; rivers, creeks, and wetlands; special-status species; and abundant recreational opportunities — from the risks of renewed oil and gas production. Members of Sierra Club are also interested in preserving the environmental integrity of sensitive areas along the pipeline route that would be exposed to the risk of another oil spill, as well as continuous excavations required by the Waivers' management program. As such, Sierra Club is beneficially interested in the outcome of this proceeding and in OSFM's performance of their legal duties.

29. Petitioner and Plaintiff SANTA BARBARA CHANNELKEEPER (SBCK) is a nonprofit organization. Its mission is to protect and restore the Santa Barbara Channel and its watersheds through science-based advocacy, education, field work, community engagement, and enforcement of environmental laws. SBCK has members who live, visit, work, and recreate in and around the area that would be affected by the restart of the Las Flores Pipeline System under the State Waivers. SBCK's members are interested in protecting resources along the 120-mile long pipeline route — including coastal resources; rivers, creeks, and wetlands; special-status species; and abundant recreational opportunities — from the risks of renewed oil and gas production. Members of SBCK are also interested in preserving the environmental integrity of sensitive areas along the pipeline route that would be exposed to the risk of another oil spill, as well as continuous excavations required by the Waivers' management program. As such, SBCK is beneficially interested in the outcome of this proceeding and in OSFM's performance of their legal duties.

30. Respondent and Defendant CALIFORNIA DEPARTMENT OF FORESTRY AND FIRE PROTECTION (CalFIRE) is, and at all relevant times hereto has been, an agency of the State of California. The OFFICE OF THE STATE FIRE MARSHAL is, and at all relevant times hereto has been, a division and component agency of CalFIRE. OSFM is charged with ensuring the safety of intrastate hazardous liquid pipelines and their compliance with state and federal laws. CalFIRE and OSFM qualify as administrative tribunals and persons for purposes of sections 1085 and 1094.5 of the

Code of Civil Procedure.

31. Respondent and Defendant DANIEL BERLANT serves as California's State Fire Marshal and is sued in his official capacity as the head of OSFM.

32. On information and belief, Real Party in Interest SABLE OFFSHORE CORP. is, and at all times relevant hereto has been, a Delaware corporation based in Houston, Texas. On information and belief, Sable Offshore Corp. is the designated operator of the Las Flores Pipeline System and applied for the State Waivers at issue.

33. On information and belief, Real Party in Interest PACIFIC PIPELINE COMPANY (PPC) is, and at all times relevant hereto has been, a Delaware corporation based in Houston, Texas. PPC is a wholly owned subsidiary of Sable. On information and belief, PPC is the owner of the Las Flores Pipeline System and, together with Sable Offshore Corp., applied for the State Waivers at issue.

34. Petitioners are ignorant of the true names or capacities of the respondents sued herein under the fictitious names DOES 1 through 10, and will seek leave to amend this petition to identify them in their true names and capacities when and if identified.

AUTHENTICITY OF EXHIBITS ATTACHED

35. Petitioners hereby incorporate by reference each and every allegation set forth above.

36. The documents accompanying this petition are true and correct copies of the original documents and are incorporated herein by reference as though fully set forth in this petition.

FACTUAL AND PROCEDURAL BACKGROUND

37. Petitioners hereby incorporate by reference each and every allegation set forth above.

Overview of the Las Flores Pipeline System

38. The Las Flores Pipeline System was constructed in the early 1990's to transport crude oil produced off the coast of Santa Barbara County to inland refineries. Today, its sole remaining purpose is to service the Santa Ynez Unit ("SYU") — a dormant oil and gas production unit located on the Gaviota Coast.

39. When operational, the SYU produces crude oil and natural gas from three offshore platforms that sit in federal waters: Harmony, Heritage, and Hondo. Once extracted, oil and gas are transported via subsea pipelines to a consolidated processing facility located in Las Flores Canyon, just

west of Goleta, California. From there, crude oil is transported inland through the Las Flores Pipeline System. The pipeline system is the only available means by which oil produced at the SYU can be transported and brought to market.

40. From its starting point in Las Flores Canyon, the Las Flores Pipeline System travels approximately 120 miles, traversing three counties en route to Pentland Station. Along the way, the buried pipeline system passes through sensitive coastal habitat, major rivers and groundwater basins, world-renowned parks and ecological reserves, and a populated suburban area.

41. As depicted above, the Las Flores Pipeline System consists of two major sections: line CA-324 (formerly "Line 901") and line CA-325 (formerly "Line 903"). CA-325 is further subdivided into sections A and B.

42. **CA-324**, the first section of the pipeline system, is a 24-inch diameter pipeline that travels westward along the Gaviota Coast in close proximity to the Pacific Ocean. It transports oil from the Las Flores Canyon processing facility approximately eleven miles to Gaviota Station.

43. The area through which CA-324 travels — the very heart of the Gaviota Coast — is of

considerable local import, and is home to globally significant natural, cultural, historical, and recreational resources. It is a spectacular rural landscape defined by rugged mountains, rolling coastal hills, and the ecologically rich Santa Barbara Channel. It is also, famously, one of the last remaining stretches of undeveloped coastline in Southern California.

44. As such, CA-324 traverses some of the most cherished and environmentally sensitive areas in Santa Barbara County, if not the state. In just eleven miles, the pipeline crosses oft-visited recreation areas; drainages, wetlands, and perennial creeks that feed directly into the nearby Pacific Ocean; and critical habitat for multiple special-status species. Most notably, the pipeline passes directly through the Arroyo Hondo Preserve — an area popular for recreation and rich in Chumash and early California history. Arroyo Hondo Creek, the central feature of the Preserve, is currently home to over two hundred federally endangered Southern California Steelhead.

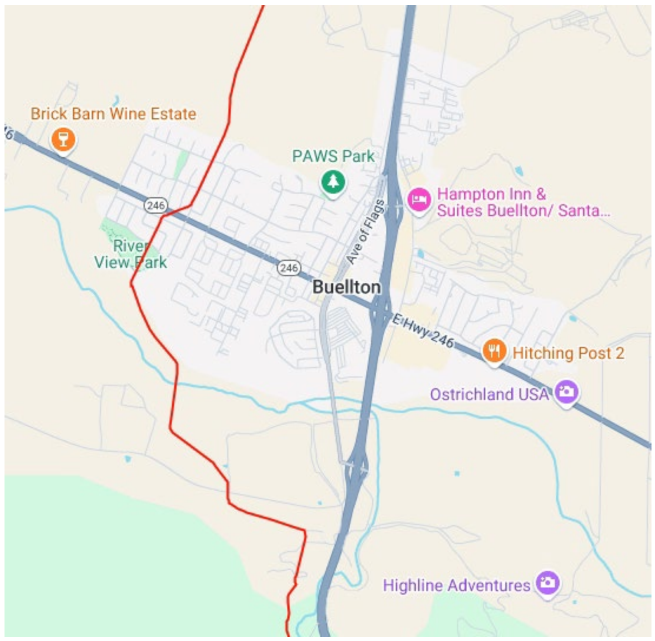
45. After CA-324 terminates at Gaviota Station, oil is transported northward via **CA-325A** — a 30-inch diameter pipeline that extends approximately thirty-eight miles to Sisquoc Station.

46. At the outset of its route, CA-325A traverses much of Gaviota State Park, where it crosses Gaviota Creek before redirecting inland. The Park provides abundant recreational opportunities to some 100,000 annual visitors. However, it also serves to protect a range of environmentally sensitive habitat areas, including oak woodland, chaparral and sage scrub, and riparian habitats. In fact, the portion of Gaviota Creek affected by the pipeline includes some of the highest quality riparian habitat remaining in southern Santa Barbara County. The perennial creek also provides critical habitat to the federally endangered Southern California steelhead and threatened California red-legged frog, as well as other special-status species, like the Southwestern pond turtle. Notably, the pipeline crosses the creek just a few hundred meters from where it empties into the Pacific Ocean.

47. After leaving the Park, CA-325A again crosses Gaviota Creek before heading northward through the Santa Ynez Mountains. En route to Sisquoc Station, CA-325A passes through multiple watersheds, dozens of creeks and drainages, and two major rivers: the Santa Ynez River and the Sisquoc River. Aside from their obvious ecological and recreational benefits, the underflows of these two rivers provide critical sources of domestic, municipal, and agricultural water supply for nearby communities. Relatedly, CA-325A permeates large swaths of three major groundwater basins — the Santa Ynez River

Valley basin, San Antonio Creek basin, and Santa Maria River Valley basin — which are some of the foremost sources of water supply in Santa Barbara County.

48. Perhaps most concerning, however, is that CA-325A passes directly through a suburban neighborhood in the city of Buellton, California. The pipeline runs by a preschool, an elementary school, and several popular parks. It also runs directly beneath, or in close proximity to, dozens of residential homes.



49. At Sisquoc Station, oil transfers to **CA-325B**, the last section of the Las Flores Pipeline System. CA-325B is a 30-inch pipeline that runs the remaining seventy-four miles to Pentland Station.

50. CA-325B begins by climbing over the rugged Sierra Madre Mountains and descending into the Cuyama River Valley, where it crosses the Cuyama River into San Luis Obispo County. Just a few miles downstream of the pipeline crossing, the Cuyama River is dammed at Twitchell, creating the Twitchell Reservoir. Among other things, the Reservoir provides an important source of groundwater recharge for the region.

51. After crossing the Cuyama River, CA-325B turns east, traveling parallel and in close proximity to the River for much of the remaining pipeline route. Before reaching its terminus, the pipeline crosses two additional areas of prominent ecological significance: the Carrizo Plain Ecological Reserve and the Bitter Creek National Wildlife Refuge. Between these two interconnected areas, the region supports the largest number of endangered, threatened, and sensitive species in the state.

52. CA-325B ultimately terminates at Pentland Station in Kern County, which marks the end of the Las Flores Pipeline System. From there, oil produced at the SYU is blended with crude oil delivered from other lines and transported to Los Angeles refineries in a separate pipeline system.

Design, Construction, and Environmental Review of the Las Flores Pipeline System

53. The inception of the Las Flores Pipeline System dates back to the early 1980's, when Celeron Pipeline Company ("Celeron") proposed building a buried pipeline system that would service oil production facilities in the Gaviota Coast area. The proposal was a subset of a larger project, known and referred to as the Celeron/All American Pipeline Project, which envisioned a pipeline route that would ultimately extend all the way to refineries in Midland, Texas.

54. In light of the scope of the Las Flores Pipeline System (described at length above), Celeron's project required approvals from a number of federal agencies, state agencies, and local governing bodies. However, construction and operation of the pipeline system was primarily overseen and permitted by the Bureau of Land Management, the California State Lands Commission, and Santa Barbara County (the "County"), which together prepared a joint Environmental Impact Report (EIR) and Environmental Impact Statement (EIS) for the project, as required by both CEQA and the National Environmental Policy Act (NEPA). A final joint EIR/EIS was certified in 1985 (the "1985 EIR/EIS"), which each agency relied on in its respective review of the project.[1]

55. Among other things, the 1985 EIR/EIS included a comprehensive description of Celeron's proposed project, from design and construction of the pipeline system through to operation and abandonment. On information and belief, it is the only surviving, publicly available document that contains a complete description of the proposed project.

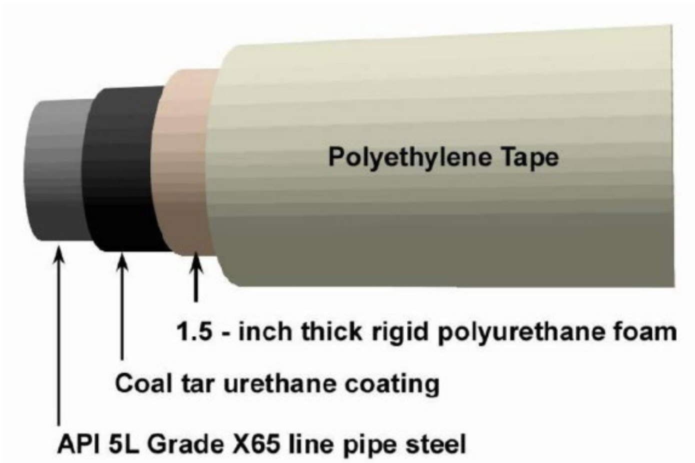
56. Of the pipeline features detailed in the 1985 EIR/EIS, two are particularly relevant here.

57. The first is the pipeline's coating and insulation system. Because of the high viscosity of the Outer Continental Shelf oil produced off Santa Barbara County, it cannot be pumped at ambient temperatures. Instead, it must be delivered to a pipeline at a relatively high temperature — e.g., as

[1] The Final EIR/EIS published in 1985 is a finalizing addendum to the 1984 Draft EIR/EIS. The preface of the Final EIR/EIS explains that the Final EIR/EIS 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/EIS. The Draft EIR/EIS is available on the County's website, at https://cosantabarbara.app.box.com/s/gc3vhh8ns8aiwketnq35vwbehnhre672. The Final EIR/EIS is likewise available at https://cosantabarbara.app.box.com/s/lkl9oo9xdsaangevdp6pasfo0cmimvlt.

proposed by Celeron, 160 degrees — and then maintained at an elevated temperature during transport. Accordingly, to minimize heat loss from the line, the 1985 EIR/EIS specified that the "[e]ntire . . . pipeline . . . would be insulated . . . with 1.5 inches of polyurethane with a vinyl outer jacket." (Draft EIR/EIS, p. 2-5.)

58. Thus, the Las Flores Pipeline System was ultimately installed with three "layers" of material: (1) a coal tar urethane coating, which was applied directly to the pipes' bare steel to help ward off corrosion; then (2) 1.5-inches of urethane foam insulation, which was sprayed onto the pipe over the coating; and, lastly, (3) a wrap of polyethylene tape, which would act as a moisture barrier and protect the insulation on the pipe.



59. The second, and perhaps most important, feature of the proposed pipeline system was its cathodic protection system — the foremost means by which the pipeline would be protected from corrosion.

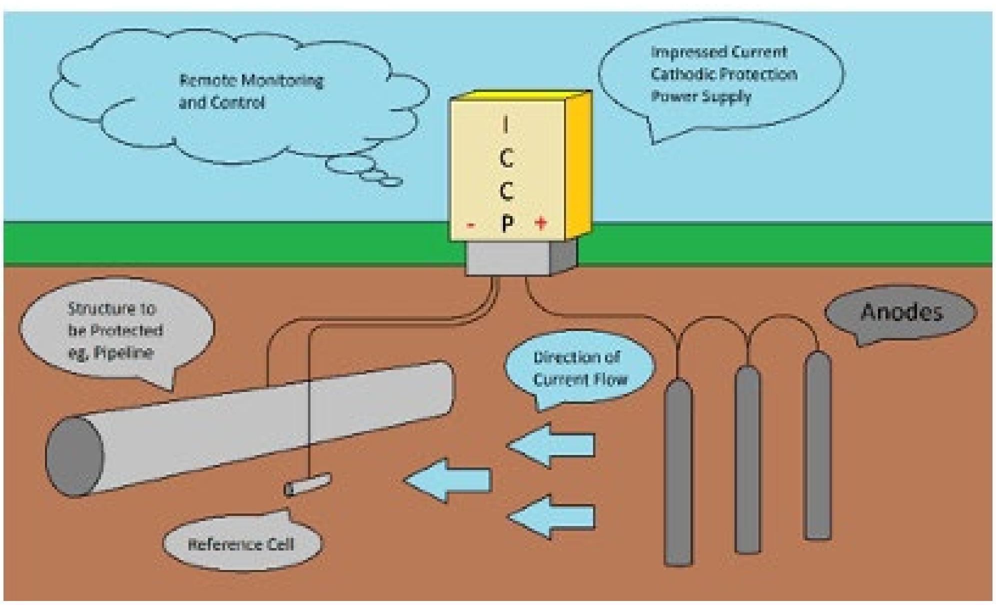
60. Corrosion, in essence, is an electrochemical reaction between metal and its environment. In steel pipelines — like the Las Flores Pipeline System — external corrosion occurs naturally over time as electrons in the pipeline's metal atoms transfer to the surrounding environment, causing metal loss from the surface of the pipe. Corrosion is especially aggressive in buried pipelines that are in direct contact with the ground.

61. The first line of protection from external corrosion is a pipeline's coating, which can prevent the flow of electrons to the pipe's surroundings. However, even the best coating will wear over time, leaving bare spots in the coating (called "holidays") where steel can leave the pipe. Thus, even if

properly coated, a buried pipeline will inevitably corrode without additional protection. Accordingly, buried pipelines are generally equipped with an additional corrosion control feature called a cathodic protection system, which targets and prevents corrosion in areas where the pipe's coating has been compromised.

62. In short, a cathodic protection system imparts an electric current onto a pipeline through a process that, when effective, causes a substitute source of metal to corrode in place of the pipeline. As long as the current is sufficient, the system theoretically prevents any corrosion of the pipeline, or at least holds it in check.

63. More specifically, a cathodic protection system works as follows: first, a device called a rectifier sends an electric current to "sacrificial" metals in the earth, which are positioned near the pipeline; next, the current picks up electrons from the metals and travels through the ground to the pipeline, which receives the electrons; and lastly, the current travels through the pipeline and back to the rectifier, completing the circuit. The pipeline's receipt of electrons from the sacrificial metals prevents it from losing electrons and corroding; the metals, meanwhile, corrode in place of the pipeline, "sacrificing" themselves to protect the pipeline. (The process effectively creates an electrochemical cell, with the sacrificial metals serving as the "anode" of the cell (which loses electrons, or "oxidizes") and the pipeline as the "cathode" (which gains electrons, or "reduces") — hence the name "cathodic protection.")



64. Federal regulations have long required that buried pipelines generally be equipped with cathodic protection. (*See* 49 C.F.R. § 195.563.) Thus, consistent with those regulations, Celeron's proposal specified that "[t]he *entire* pipeline would be protected from corrosion with cathodic protection systems." (Draft EIR/EIS, p. 2-5). To ensure the cathodic protection system was functioning as intended, the system would be periodically inspected and maintained, and "[c]orrosion control test stations would be installed with which to test the integrity of the corrosion protection." (Draft EIR/EIS, pp. 2-5, 2-32, 4-106).

65. The importance of the proposed cathodic protection system, and its centrality to the project itself, cannot be overstated. As the pipelines' ultimate means of corrosion control, cathodic protection was foundational to the overall design of the Las Flores Pipeline System and the success of the project. As the 1985 EIR/EIS acknowledged, "[p]rotection of a pipeline from corrosion is of *critical importance* to the environment as well as the pipeline operator"; without such protection, the strength of the pipeline wall can deteriorate, leading to a break in the pipe and a possible oil spill. (Draft EIR/EIS, p. 4-106 (emphasis added).)

66. Relatedly, environmental review of the project was largely premised on an effective cathodic protection system. Indeed, in predicting the likelihood of an oil spill — the primary environmental impact considered — the 1985 EIR/EIS explicitly relied on cathodic protection as a design specification that "would reduce the probability of an event [i.e., oil spill] occurring," and would be "very effective" in doing so. (Final EIR/EIS, pp. 2-57, Appendix 4.3.)

67. After certification of the 1985 EIR/EIS, Celeron received all necessary approvals for construction and operation of the Las Flores Pipeline System. Celeron proceeded with construction in the late 1980's, and the pipeline system went into service in or around 1992.

68. In 1998, the pipeline system was acquired by Plains Pipeline, L.P., a wholly owned subsidiary of Plains All American Pipeline, L.P. (together, "Plains"), which would own and operate the pipelines for the majority of their life.

The 2015 Refugio Oil Spill and Ineffectiveness of Cathodic Protection

69. On May 19, 2015, CA-324 ruptured near Refugio State Beach Park, releasing more than 120,000 gallons of heavy crude oil into the surrounding environment. The spill devastated

approximately 150 miles of the California coast. Thousands of acres of shoreline and subtidal habitat were destroyed, and an untold number of animals — including marine mammals — were injured or killed. The spill also forced the closure of fisheries and beaches, which jeopardized local businesses and caused an estimated 140,000 lost recreational user days between Santa Barbara and Ventura Counties.

70. The spill was one of the largest in California history, and the damage to the region's unparalleled resources was immeasurable. However, the economic toll of the spill was also considerable. To date, Plains, which owned and operated the Las Flores Pipeline System at the time of the spill, has spent upwards of $870M in clean up costs, remediation, and compensatory damages to various third parties. $200M of that went to local business and property owners affected by the spill.

71. Upon investigation, PHMSA determined that the rupture in CA-324 was a result of "progressive external corrosion," and that the pipeline's cathodic protection system — intended to prevent such corrosion — was ineffective.[2] Without sufficient protection from corrosion, the pipeline wall had thinned as much as 89% at the point of rupture, and was thus no longer able to withstand the internal pressure of operations. Notably, the pipeline was only operating at approximately 55% of its maximum operating pressure at the time it failed.

72. As it turns out, the ineffectiveness of cathodic protection on CA-324 was a product of the pipeline's flawed design. Specifically, the various layers of material installed on the pipeline — its coating, foam insulation, and outer protective tape wrap — created conditions that prevented the pipeline's cathodic protection system from functioning as intended.

73. The coal tar urethane coating installed on the Las Flores Pipeline System is an older type of coating that is nonconductive, meaning cathodic protection current cannot pass through it. It also has a tendency to lose its adhesion over time, becoming separated or disbonded from the pipe. When it becomes disbonded — as it did here — moisture can reach the pipe's bare steel and form corrosion cells underneath the coating. Those corrosion cells, in turn, can cause many different forms of corrosion, including stress corrosion cracking and selective seam corrosion cracking, *which cannot be prevented or remedied by cathodic protection*.

[2] PHMSA's Failure Investigation Report, cited herein, is available on PHMSA's website, at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/PHMSA_Failure_Investigation_Report_Plains_Pipeline_LP_Line_901_Public.pdf.

74. The pipeline's insulation and protective tape barrier separately rendered cathodic protection ineffective on the line, for a few reasons. First and foremost, the external tape wrap installed on the pipeline is not conductive, and it thus acted to prevent cathodic protection current from reaching the pipeline's wall. Likewise, the underlying foam insulation worked to shield the pipeline from the electric current.

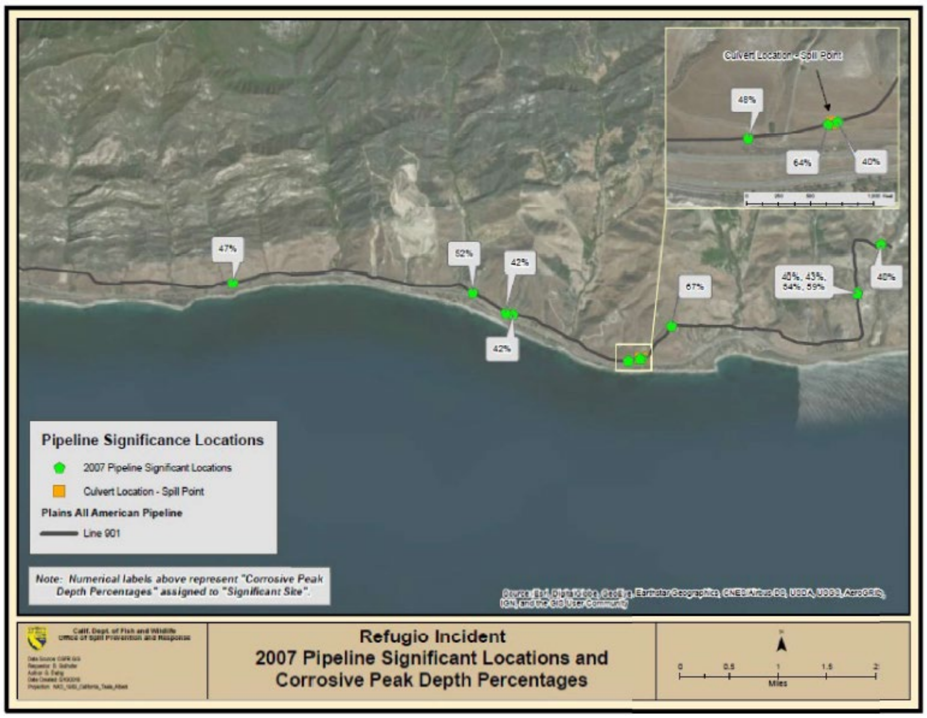
75. Additionally, the pipeline's external tape wrap wrinkled and cracked over time, allowing water to saturate the underlying foam insulation and, eventually, ingress all the way to the pipeline wall. Water then accumulated along the pipeline and migrated to the lowest local elevation point, becoming trapped beneath the insulation. Where the moisture reached the pipe's bare steel, it created corrosion cells that aggressively ate away at the pipe over time. This phenomenon, called "corrosion under insulation," was identified as "the primary corrosion mechanism" that led to the rupture in CA-324. (PHMSA Failure Investigation Report, Appendix M, p. 18.) According to PHMSA, cathodic protection cannot prevent "corrosion under insulation" when, as here, the outer wrap that protects the insulation inevitably becomes compromised. (PHMSA Failure Investigation Report, p. 14.)

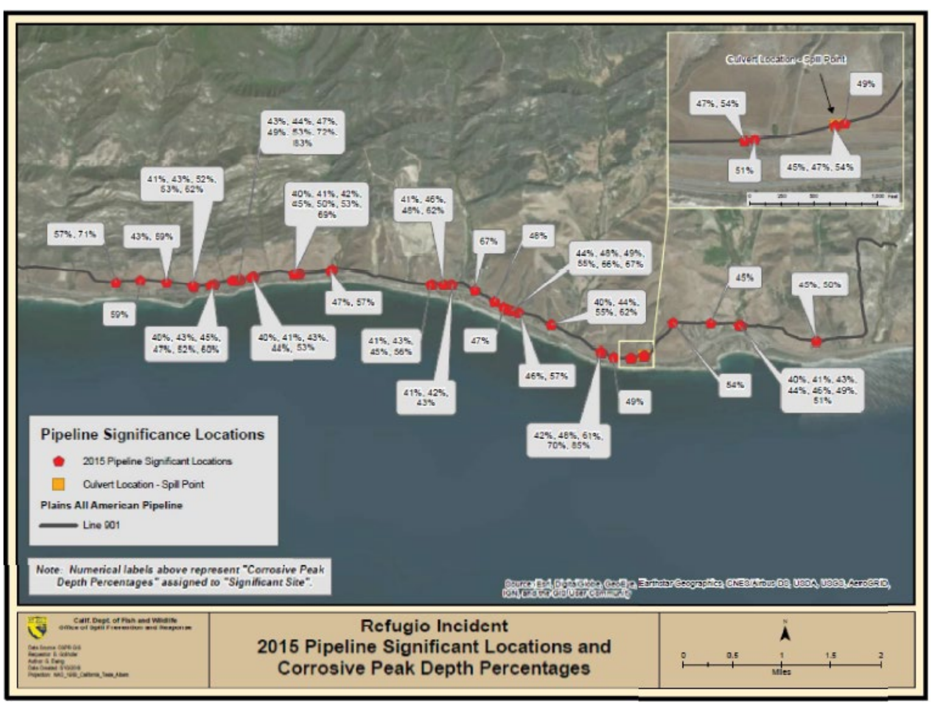
76. Importantly, the above issues were not limited to CA-324. Ultimately, **PHMSA found pervasive metal loss throughout the entirety of the Las Flores Pipeline System, and it concluded that cathodic protection is ineffective on both CA-324 and CA-325**. (PHMSA Failure Investigation Report, pp. 3, 14, Appendix E.) That information was not known until 2016 — more than thirty years after the 1985 EIR/EIS was certified.

77. PHMSA further concluded that, as a general matter, "[cathodic protection] is ineffective on buried, insulated pipelines" writ large. (PHMSA Failure Investigation Report, Appendix E, p. 2.) On information and belief, it may have been previously understood that buried, insulated lines could be susceptible to aggressive corrosion, but the earliest report considering the ineffectiveness of cathodic protection on such lines, prepared by the National Association of Corrosion Engineers (NACE), was not issued until 1992 — seven years after the 1985 EIR/EIS was certified.

78. In addition to the failure of the pipeline's cathodic protection system, PHMSA cited another factor that contributed to the spill: Plains' failure to properly detect and mitigate corrosion.

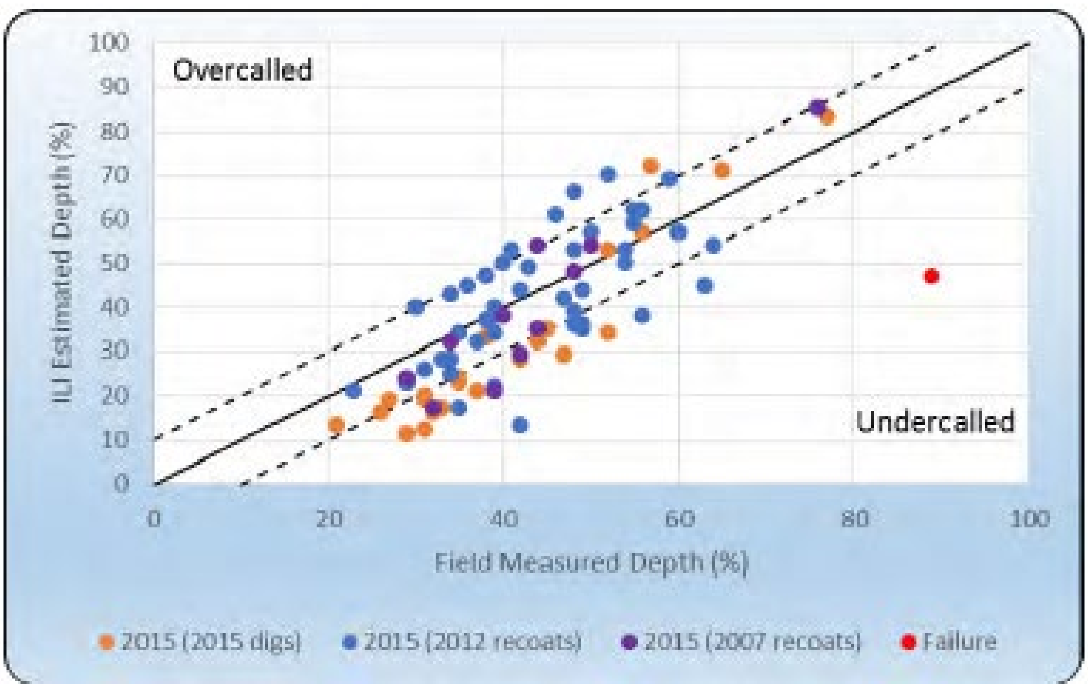
79. In the years leading up to the spill, Plains had been periodically running an in-line inspection ("ILI") tool to assess the integrity of the Las Flores Pipeline System, as required by federal regulations. The ILI surveys, unsurprisingly, revealed an alarming pattern of progressive corrosion. The below charts depict results from ILI surveys that Plains conducted on CA-324 in 2007 and May 6, 2015, and show the areas where, according to the surveys, the pipeline wall had corroded more than 40%.





80. Equally alarming is that the ILI tool used by Plains proved to be inaccurate and unreliable. When Plains performed exploratory digs to corroborate the results of its 2007 and 2012 ILI surveys — as required by federal regulations — its field measurements were inconsistent with the ILI results. In many areas, the ILI tool had significantly underestimated (or "undercalled") the depth of corrosion that was actually present. Plains, however, did not consult its ILI vendor about the inaccuracies or take any meaningful steps to resolve the issue.

81. PHMSA's investigation, which included a number of its own exploratory excavations, revealed that Plains' May 2015 ILI survey was likewise inaccurate. According to PHMSA, the ILI tool was only "accurate," per industry standards, 57% of the time. And it had wildly undercalled the corrosion in the area where the pipeline ultimately ruptured. While the 2015 survey showed a corrosion depth of 49%, in actuality the pipeline wall had thinned about 89%. The chart below compares the 2015 ILI survey results with measurements taken in the field, depicting the inaccuracy of the ILI tool.



82. Following the Refugio Oil Spill, PHMSA issued a series of Corrective Action Orders (CAOs) requiring, *inter alia*, that the Las Flores Pipeline System be emptied, purged, and idled, and it remains idle to date. Due to the unavailability of the pipeline system, the SYU was shut in, and production at the unit was suspended indefinitely. Neither the Las Flores Pipeline System nor the SYU have been operated for almost ten years.

Transfer of Jurisdiction to OSFM and Conditions for Restarting

83. At the time of the Refugio Oil Spill, the Las Flores Pipeline System was classified as an *interstate* pipeline system and, thus, was subject to the exclusive regulatory jurisdiction of PHMSA. However, following the spill, Plains cancelled its Federal Energy Regulatory Commission (FERC) certificates for the pipeline system, acknowledging that the pipelines had never actually been used to facilitate interstate commerce and, in any event, were no longer available to do so. By cancelling its FERC certificates, Plains effectively reclassified the Las Flores Pipeline System as an *intrastate* pipeline system, which transferred regulatory and enforcement jurisdiction over the pipelines to OSFM.

84. In May 2016, PHMSA formally acknowledged the reclassification of the pipelines and the transfer of jurisdiction to OSFM. The pipelines, which were previously known as Lines 901 and 903, were given the new monikers CA-324 and CA-325, respectively, and rebranded as the Las Flores Pipeline System.

85. Several years later, PHMSA, OSFM, and a number of other state and federal agencies sued Plains seeking civil penalties and compensation for natural resource damages associated with the spill. (*U.S. v. Plains All American Pipeline*, United States District Court for the Central District of California, Civil Action No. 2:20-cv-02415.) The parties settled, and the agreement was memorialized in a Consent Decree entered by the court.[3]

86. In addition to imposing monetary penalties on Plains, the Consent Decree contemplated the future of the Las Flores Pipeline System. It offered three paths forward for Plains (and any subsequent owner) in light of the pipelines' design defects. First, Plains could simply abandon and decommission the defunct pipelines. Second, Plains could replace the pipeline system with new, non-insulated pipe, which could potentially allow cathodic protection to function properly. And last, as a third and final option, Plains could restart the existing pipelines, but only under strict conditions.

87. As relevant here, those restart conditions included the following: (1) complete all remaining corrective actions required by PHMSA's CAOs, such as repairing metal loss anomalies on the pipelines; (2) install new automatic shutoff valves along the Las Flores Pipeline System, which,

[3] The Consent Decree is available on the Environmental Protection Agency's website, at https://www.epa.gov/sites/default/files/2020-03/documents/plainsallamericanpipelinelp.pdf.

importantly, do not *prevent* a spill, but can help reduce the volume of a spill should one occur; and (3) obtain State Waivers from OSFM "for the limited effectiveness of cathodic protection" on both CA-324 and CA-325, which would excuse Plains from complying with the regulations that require cathodic protection. (Consent Decree, at Appendix B, Article I, § 1.) Notably, nowhere does the Consent Decree suggest that OSFM *must* issue a State Waiver for either CA-324 or CA-325.

88. Should Plains complete (1), (2), and (3) above, the final step in the restart process would be (4) submitting Restart Plans to OSFM for review and approval, and obtaining ultimate approval from OSFM to restart CA-324 and CA-325. The Consent Decree is clear that neither Plains nor any subsequent owner/operator may operate CA-324 or CA-325 "until authorized to do so by OSFM," at OSFM's discretion.

Interim Efforts to Restart the SYU and the Las Flores Pipeline System

89. Recall that the Las Flores Pipeline System is integral to the viability of the SYU; without it, oil produced at the SYU cannot be transported or brought to market. Hence, the SYU was shut-in when the pipeline system was taken offline in 2015. Notably, in the last full year it was active, the SYU was responsible for 50% of all greenhouse gas emission in Santa Barbara County.

90. With the Las Flores Pipeline System out of service, ExxonMobil ("Exxon"), the longtime owner and operator of the SYU, first attempted to resume production at the SYU by bypassing the pipeline system altogether. Specifically, it applied to the County for permission to truck, rather than pipe, its oil from Las Flores Canyon to Kern County. The County denied Exxon's application in March 2022, citing obvious environmental and safety concerns.

91. Meanwhile, Plains sought to replace the Las Flores Pipeline System, ostensibly due to the risk the corroded pipelines pose to public health and safety.

92. Plains applied to the County for the necessary land use permits, and the County began conducting environmental review of Plains' proposal, as required by CEQA. In preparing a Draft EIR for the project, the County considered, as an alternative to replacement, the impacts of simply restarting the existing pipelines. An analysis prepared by the County's consultants suggested that restarting the defective pipelines would not only invite another disastrous spill, but all but ensure it. Relying on a report prepared by OSFM, the analysis found that, without effective cathodic protection, the risk of a

spill from the pipelines was *five times greater* than initially estimated. **The analysis further concluded that restarting — rather than replacing — the Las Flores Pipeline System could result in a spill once a year, and a rupture (a spill greater than five barrels) every four.** And a spill in the coastal zone, it found, could be nearly twice the size of the 2015 spill, even with the addition of automatic shut-off valves. An excerpt of this analysis is attached hereto as **Exhibit A**.

93. As Plains' application to replace the pipelines was pending, Plains sold the Las Flores Pipeline System to PPC, then a wholly-owned subsidiary of Exxon. Shortly thereafter, on October 24, 2023, Exxon withdrew the application. In reneging on the plan to replace the pipeline system, it cited, in part, "a high degree of local permitting and business uncertainty . . . that has impacted investment commitment . . . ."

94. Pivoting, Exxon instead sought to *restart* the existing Las Flores Pipeline System, despite the threat of another spill from the defective pipelines. Pursuant to the Consent Decree, on July 10, 2023, Exxon, via PPC, applied to OSFM for State Waivers for the limited effectiveness of cathodic protection on CA-324 and CA-325.

95. Exxon's restart proposal would also require retrofitting the Las Flores Pipeline System with new safety valves, as mandated by the Consent Decree and Government Code section 51013.1 — a pipeline safety statute enacted in response to the Refugio Oil Spill. Installation of the valves, however, required County approval.

96. The County Planning Commission denied Exxon's application to install new valves, which, again, would facilitate restart of the defective pipeline system. The Planning Commission rejected the idea that the Las Flores Pipeline System could be safely or responsibly restarted, pointing to the pipelines' degraded condition and ineffective cathodic protection system. On appeal, the Board of Supervisors voted 2-2 on the issue, effectively denying Exxon's application.[4]

97. Having repeatedly failed in its attempts to restart the SYU, Exxon eventually looked to offload its SYU assets. Enter Sable, a new, speculative entity formed to chance the regulatory hurdles that Exxon failed to clear.

[4] Exxon later sued the County in United States District Court for the Central District of California, Case No. 2:23-cv-09218-DMG-MRW. After Sable acquired PPC, the parties reached a settlement agreement that cleared the way for PPC to install the valves.

Sable's Acquisition and Haphazard Efforts to Restart the Las Flores Pipeline System

98. Sable Offshore Corp. began in 2020 as several special purpose entities, which were organized to evaluate and facilitate a potential acquisition of the SYU and associated assets. The corporations were formed by current Sable CEO Jim Flores, who had just led a different, troubled venture to bankruptcy.

99. On February 14, 2024, Sable Offshore Corp. acquired the SYU from Exxon and all its associated assets: the three offshore platforms, the subsea pipelines and infrastructure, and the Las Flores Canyon processing facilities. Sable Offshore Corp. also acquired PPC, and with it, the defunct Las Flores Pipeline System.

100. However, Sable, being undercapitalized, lacked the financial resources to fund the $625M deal with Exxon. Thus, Sable was forced to secure a $622M loan from Exxon — a whopping 99% of the purchase price — just to finance it. In exchange, Sable agreed that the SYU assets may, at Exxon's option, revert to Exxon if the SYU is not back online by early 2026.

101. The SYU assets — which have not been operational since 2015 — remain Sable's only assets, leaving Sable without a reliable or predictable source of revenue. Sable is currently operating at an astounding ~$700M deficit, and it will continue operating at a deficit unless and until it restarts the SYU. Hence, according to Sable itself, "substantial doubt exists about the Company's ability to continue," and it "may have insufficient funds available to operate its business prior to first production."

102. With the clock ticking on Sable's ability and window to restart the SYU, Sable is, predictably, trying to cut any regulatory corners it can.

103. Following in Exxon's footsteps, Sable is attempting to restart, rather than replace, the defective Las Flores Pipeline System, which has now aged past its expected lifespan. And, as it rushes to bring the Las Flores Pipeline System back online, Sable has repeatedly violated state law, ignored directives from state agencies, and otherwise shown an aversion to regulatory compliance.

104. Recall that, in order to restart the pipelines, the Consent Decree requires that Sable install additional safety valves along the pipeline system and conduct repairs where severe corrosion has been detected. On information and belief, beginning September 2024, Sable began extensive excavations along the pipeline route, including in wetlands, critical habitat for special-status species, and other

sensitive areas — all without coordinating with relevant agencies or applying for necessary permits.

105. When the California Coastal Commission (CCC) got wind of Sable's activities, it issued Sable a Notice of Violation (NOV) clarifying that Sable is required to obtain Coastal Development Permits (CDPs) for both the valve installations and repair work. Alarmingly, *Sable continued working despite the NOV*, prompting the CCC to issue a second NOV and, ultimately, a Cease-and-Desist Order, which directed Sable to apply for CDPs.

106. Separately, in December 2024, Sable received two NOVs from the Regional Water Quality Control Board alerting it of violations of the Clean Water Act and California Water Code and directing it to apply for necessary permits. Sable also received an NOV from the California Department of Fish and Wildlife (CDFW), which alleged that Sable had potentially trespassed on state property, harmed endangered species, and improperly disturbed a number of streambeds.

107. On information and belief, Sable temporarily ceased work in response to the above NOVs. However, on February 14, 2025, Sable resumed work on the Las Flores Pipeline System — willfully ignoring state law and many of the above NOVs. The CCC was forced to issue yet another Cease-and-Desist Order, and *Sable proceeded to continue work in violation of the order*. At a March 13, 2025, town hall, a representative of CCC stated that never in the history of the CCC had a company so brazenly violated a Cease-and-Desist Order.

108. Due to Sable's continuous violations of state law, on April 10, 2025, the CCC issued Sable an ~$18M fine — the maximum penalty it could impose and the largest in the agency's history.

109. On information and belief, Sable has now completed installing new valves on the pipeline system as well as the vast majority of its planned repair work — two key prerequisites to restart. However, as discussed above, there are still a few other boxes that Sable must check before restarting, including obtaining State Waivers from OSFM.

OSFM Grants State Waivers with No Public Process, Environmental Review, or Justification

110. On April 24, 2024, Sable, via PPC, notified OSFM that it would be assuming Exxon's applications for State Waivers for CA-324 and CA-325, which had been pending since July 2023. The applications requested, pursuant to the Consent Decree, permission to operate despite the limited effectiveness of cathodic protection on the pipelines. They also "request[ed] relief from the requirements

to evaluate and remediate all corrosion of or along longitudinal seam welds per 49 C.F.R. § 195.452(h)(4)(iii)(H).” Sable’s April 24, 2024 correspondence, with the two applications attached, is attached hereto as **Exhibit B**.

111. In light of the threat to public health and safety posed by the Las Flores Pipeline System, beginning in March 2024, community organizations began asking OSFM for increased transparency and public engagement as it considered whether to permit the restart of 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,” including, specifically, “at the State Waiver step of the process.”

112. On September 27, 2024, Petitioners EDC, SBCAN, and GOO! sent a letter to OSFM renewing their request for a public process. Petitioners explained that not only was a public hearing appropriate under the circumstances but, in the case of the State Waivers, required by law. Petitioners also pointed out that operating the Las Flores Pipeline System without effective cathodic protection was neither anticipated nor reviewed in the 1985 EIR/EIS or any project approval, and the potential impacts of doing so have never been fully considered. Thus, the letter also called on OSFM to conduct environmental review of Sable’s State Waiver applications, as well as Sable’s broader restart proposal, pursuant to its obligations under CEQA. Petitioners’ September 27, 2024 letter is attached hereto as **Exhibit C**. OSFM never responded to the letter.

113. Also on September 27, 2024, thirteen state legislators sent a letter of their own to OSFM echoing the calls of community organizations for environmental review of Sable’s restart proposal and a transparent public process. The letter stated that the legislators “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. . . . [O]ne 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.” The legislators’ September 27, 2024 letter is attached hereto as **Exhibit D**.

114. On November 7, 2024, OSFM responded to the state legislators. It inaccurately downplayed its role in overseeing the restart of the Las Flores Pipeline System, and it refused to commit to conducting environmental review or holding a formal public process. However, acknowledging “the

public's considerable interest in the restart of these pipelines," OSFM reiterated its commitment to hold a "public meeting" — not a hearing — at an indefinite point in the future. On information and belief, the agency also verbally committed to holding the "public meeting" *before* making a determination on Sable's State Waiver applications.

115. On December 17, 2024, without having held any sort of "public meeting," OSFM preliminarily approved the State Waiver applications. OSFM did not offer any sort of public process in advance of its decision, or even release key documents (like the applications themselves). Nor did it conduct environmental review of the State Waiver applications. In other words, in approving the Waivers, OSFM entirely disregarded applicable procedural requirements, critical environmental laws, and its own previous commitments to state legislators and the public.

116. On December 23, 2024, EDC and Center for Biological Diversity submitted to OSFM an expert report prepared by Accufacts, Inc. — the first of two such reports. The report explained why cathodic protection is ineffective on the Las Flores Pipeline System. It also identified deficiencies in ILI technologies which lead to inaccurate assessments of external corrosion threats that most likely exist on the pipelines. Notably, the report explained why the pipelines were at risk of failure and cannot be made as safe as new pipelines. Accufacts, Inc.'s first report is attached hereto as **Exhibit E**. OSFM did not respond to the report.

117. OSFM submitted the State Waivers to PHMSA on December 18, 2024, triggering a 60-day review period for PHMSA to consider the Waivers. On February 11, 2025, PHMSA notified OSFM that it would not object to either State Waiver, rendering the Waivers final and effective. The State Waivers for CA-324 and CA-325 are attached hereto as **Exhibits F and G**, respectively.

118. As requested by Sable, the State Waivers permit the operation of CA-324 and CA-325 despite their lack of effective cathodic protection, and, separately, relieve Sable of compliance with 49 C.F.R. § 195.452(h)(4)(iii)(H), so long as Sable complies with some sixty conditions outlined in the Waivers. According to OSFM, the conditions ensure that the pipelines will be "as safe or safer" than if they had effective cathodic protection.

119. At first blush, the imposition of sixty-plus conditions would suggest that the Waivers comprehensively address the pipelines' defects and safety issues. But a closer review reveals substantial

and concerning deficiencies with the Waivers.

120. In short, the Waivers substitute cathodic protection with more frequent inspections of the pipelines using ILI tools — tools which we know from the 2015 spill to be demonstrably unreliable. In other words, rather than *proactively* preventing corrosion in the first place with proven technology, the Waivers instead rely on purely *reactive* measures — i.e., attempting to track down corrosion (with inherently unreliable tools), locate anomaly sites in the field, and properly repair them — which leave room for technical and operator error.

121. Put differently, the Waivers allow for the pervasive, progressive corrosion of the Las Flores Pipeline System that we saw leading up to the 2015 spill to continue, and naively hope that Sable will do a better job than Plains at detecting and remediating it. Yet there is little reason to suspect that will be the case. The tools themselves, we know, can be inaccurate. And Sable — a new, speculative company that has never actually operated an oil and gas pipeline — has done little to assure that it can or will comply with the maintenance program contemplated by the Waivers. In fact, considering its pattern of regulatory aversion and violations, all we have definitively seen from Sable is the opposite.

122. The many deficiencies of the Waivers are explained at length in a second expert report prepared by Accufacts, Inc., which is attached hereto as **Exhibit H**. The report concludes that, contrary to OSFM's determination, the Las Flores Pipeline System will not be made safe by the Waivers' conditions.

123. Perhaps realizing the indefensibility of the Waivers, OSFM did not even bother to provide any supportive reasoning for its decisions. Indeed, the Waivers do not include *any* analysis as to why the pipelines will be "as safe or safer" than if they had effective cathodic protection, despite such an analysis being required by state and federal law.

124. On information and belief, OSFM's approvals here were unconventional and unprecedented. The Waivers are, for all intents and purposes, entirely experimental. In fact, the State Fire Marshal, Daniel Berlant, all but admitted as much at a town hall on March 13, 2025, acknowledging that a number of other jurisdictions are closely watching to see how the Waivers play out.

125. Given the "experimental" nature of the Waivers, and the critical resources that this 120-mile-long pipeline system can impact, the need for public comment, independent expert scrutiny, and

environmental review was especially critical here, as highlighted by the two reports prepared by Accufacts, Inc. Instead, OSFM pushed the Waivers through behind closed doors, reneging even on its minimal commitment to first have a public meeting on the issue.

LEGAL BACKGROUND

126. Petitioners hereby incorporate by reference each and every allegation set forth above.

OSFM's Delegated Authority under the Federal Hazardous Liquid Pipeline Safety Act

127. Pipeline safety is generally regulated by the federal government pursuant to the federal Hazardous Liquid Pipeline Safety Act (the "Federal PSA"), 49 United States Code section 60101 *et seq*., which is administered by PHMSA. However, the extent of the federal government's regulatory authority varies between interstate and intrastate pipelines.

128. For *interstate* pipelines, PHMSA has exclusive jurisdiction over matters of pipeline safety. In fact, state authorities are expressly preempted from "adopt[ing] or continu[ing] in force safety standards for interstate pipeline facilities. (49 U.S.C. § 60104(c).)

129. However, PHMSA's authority over *intrastate* pipelines — like the Las Flores Pipeline System — is merely provisional. Pursuant to 49 U.S.C. section 60105, states have the option to assume exclusive responsibility for regulating intrastate pipelines by submitting an annual certification to the Secretary of Transportation ("Certification"). Among other things, the Certification must affirm that the state has adopted the minimum federal pipeline safety standards, which are outlined in Title 49 of the Code of Federal Regulations, Part 195 ("Part 195").

130. Once a state has submitted a valid Certification, exclusive regulatory and enforcement authority over intrastate pipelines passes to the state. (*See* 49 U.S.C. § 60105(a).) Indeed, PHMSA is prohibited from "prescrib[ing] or enforc[ing] safety standards and practices" on intrastate pipelines that are regulated under a certified program. (49 U.S.C. § 60105(a).)

131. Like most other states, California has and maintains such a Certification, giving it the authority to regulate its intrastate pipelines. That authority is delegated to OSFM, which administers the state's pipeline safety laws and regulations under color of the Certification. (*See* Gov. Code, § 51010.) OSFM also effectively administers the federal safety standards outlined in Part 195, which, as required for Certification, are incorporated by reference in California's pipeline safety regulations. (*See* 19

C.C.R. § 2000.)

State Waivers under the Federal PSA

132. Where a state has a valid Certification, the Federal PSA grants state authorities the flexibility to depart from federal minimum safety standards. They are free, for example, to impose more stringent safety standards than those required by federal law. (49 U.S.C. § 60104(c).) Or, they can excuse compliance with federal safety standards by issuing a "State Waiver." (49 U.S.C. 60118(d).)

133. Specifically, 49 U.S.C. section 60118 provides that, "[i]f a [Certification] . . . is in effect, the State authority *may*" — i.e., at its discretion — "waive compliance with a safety standard to which the [C]ertification . . . applies." (49 U.S.C. 60118(d) (emphasis added).) However, the statute imposes an important limitation on that authority: a State Waiver can only be issued "*in the same way and to the same extent* that the Secretary [of Transportation] may waive compliance under subsection (c)" of the statute. (49 U.S.C. § 60118(d) (emphasis added).) In other words, while a state authority has the discretion to grant a State Waiver, it can only do so by following the standards and procedures set forth in 49 U.S.C. section 60118(c).

134. 49 U.S.C. section 60118(c), in turn, outlines the corollary authority of the Secretary to waive federal safety standards for pipelines directly under PHMSA's jurisdiction — e.g., interstate pipelines.[5] (49 U.S.C. 60118(c).) It prescribes the procedures by which the Secretary may issue a waiver and sets forth the substantive standard for issuing both "nonemergency" and "emergency" waivers. (*Id.*)

135. For "nonemergency waivers," subsection (c) provides that the Secretary can issue a waiver "on terms the Secretary considers appropriate if the Secretary determines that the waiver is not inconsistent with pipeline safety." (49 U.S.C. § 60118(c)(1)(A).) However, as relevant here, subsection (c) explicitly states that "[t]he Secretary may act on a waiver . . . *only after notice and opportunity for a hearing*." (49 U.S.C. § 60118(c)(1)(B) (emphasis added).) And, it directs that "[t]he Secretary *shall* state in an order issued under this subsection the reasons for granting the waiver." (49 U.S.C. § 60118(c)(3) (emphasis added).)

136. Again, the provision authorizing state authorities to issue waivers incorporates the standards and procedures outlined in 49 U.S.C. section 60118(c). (49 U.S.C. § 60118(d).) Thus, to grant

[5] When the Secretary issues a waiver, it is the functional equivalent of a State Waiver, but it is called a "Special Permit."

a State Waiver, a state authority must (1) provide the public with notice and an opportunity for a hearing on the waiver application, (2) properly determine that the waiver would not be inconsistent with pipeline safety, and (3) provide a statement of reasons explaining its decision. (49 U.S.C. § 60118(c), (d).) Where a state authority fails to comply with one or more of these requirements, it violates the Federal PSA.

137. Additionally, before issuing a State Waiver, a state authority "must give the Secretary written notice of the waiver at least 60 days before its effective date." (49 U.S.C. § 60118(d).) The Secretary can concur with the waiver, object, or simply let the sixty days lapse without taking any action. (*See id.*) Should the Secretary concur or take no action, the waiver becomes final and effective.

Additional Waiver Requirements under the State Elder Pipeline Safety Act

138. California's Elder Pipeline Safety Act of 1981 (the "State PSA"), Government Code section 51010 *et seq.*, is the state's preeminent pipeline safety law. To the extent allowed by the Federal PSA, it grants the State Fire Marshal the "exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines" in California, and it outlines a number of pipeline safety requirements above and beyond what is required by federal minimum standards. (*See* Gov. Code, § 51010.)

139. The State PSA also directs the State Fire Marshal to "adopt hazardous liquid pipeline safety regulations in compliance with federal law." (Gov. Code, § 51011.) As noted above, among the regulations that OSFM has adopted is 19 C.C.R. section 2000, which incorporates by reference the entirety of Part 195.

140. Like the Federal PSA, the State PSA allows for the waiver of certain safety requirements. However, it imposes a higher standard for such "exemptions." It states: "The State Fire Marshal may exempt the application of regulations adopted pursuant to this section" — like Part 195's federal minimum safety standards — "to any pipeline, or portion thereof, when it is determined that the risk to public safety is slight and the probability of injury or damage remote." (Gov. Code, § 51011(b).)

141. Should the State Fire Marshal grant an exemption, it must be in writing, and the notice of exemption "shall include a discussion of those factors that the State Fire Marshal considers significant to the granting of the exemption." (Gov. Code., § 51011(c).)

California Environmental Quality Act

142. CEQA was enacted to ensure that government agencies consider the environmental consequences of their actions before approving projects. (Pub. Res. Code, §§ 21000 *et. seq*.) CEQA's statutory requirements are further defined and implemented by the "CEQA Guidelines." (14 Cal. Code Regs., §§ 15000 *et. seq.*)

143. A central element of CEQA is to require public agency decision makers to evaluate and document the potential environmental implications of their actions. (Pub. Res. Code, §§ 21000, 21001; CEQA Guidelines, §§ 15002, 15003; *Friends of Mammoth v. Board of Supervisors* (1972) 8 Cal. 3d. 247, 254-56.) In enacting CEQA, the state legislature intended the law "to be interpreted in such a manner as to afford the fullest possible protection to the environment . . . ." (CEQA Guidelines, § 15003(f); *Friends of Mammoth*, 8 Cal. 3d at 259.)

144. CEQA contains both procedural and substantive requirements. A critical procedural requirement is the need to prepare an EIR for projects that may result in a significant effect on the environment. (CEQA Guidelines, § 15064.) The purpose of an EIR is to consider the significant effects of a project, as well as alternatives and mitigation measures that can avoid or mitigate such effects. (Pub. Res. Code, §§ 21002.1, 21061; CEQA Guidelines, §§ 15003, 15126, 15126.2, 15126.4, 15126.6.) The EIR requirement "is the heart of CEQA." (CEQA Guidelines, § 15003(a); *County of Inyo v. Yorty* (1973) 32 Cal.App.3d 795, 810.) "The EIR process protects not only the environment but also informed self-government." (*Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal. 3d 376, 392.)

145. In addition to the procedural requirements of CEQA, the law contains a "substantive mandate" requiring agencies to impose feasible alternatives and/or mitigation measures to avoid or substantially lessen the environmental effects of projects. (Pub. Res. Code, § 21002; CEQA Guidelines, § 15091.) These alternatives and mitigation measures must first be identified and discussed in an EIR. (CEQA Guidelines §§ 15126.4, 15126.6.)

146. Public participation is essential to the function of CEQA. (Pub. Res. Code, § 21000(e); *Environmental Planning and Information Council v. County of El Dorado* (1982) 131 Cal. App. 3d 350, 354 ("A paramount consideration is the right of the public to be informed in such a way that it can

intelligently weigh the environmental consequences of any contemplated action and have an appropriate voice in the formulation of any decision.”).)

147. When an EIR has been prepared for a project, subsequent or supplemental environmental review is required if certain events occur which may result in new or increased significant effects on the environment. (Pub. Res. Code § 21166; CEQA Guidelines § 15162(a).) Specifically, a subsequent EIR is required where:

> (1) Substantial changes are proposed in the project which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects;
>
> (2) Substantial changes occur with respect to the circumstances under which the project is undertaken which will require major revisions of the previous EIR or Negative Declaration due to the involvement of new significant environmental effects or a substantial increase in the severity of previously identified significant effects; or
>
> (3) New information of substantial importance, which was not known and could not have been known with the exercise of reasonable diligence at the time the previous EIR was certified as complete or the negative declaration was adopted, shows any of the following:
>
> > (A) The project will have one or more significant effects not discussed in the previous EIR or negative declaration;
> >
> > (B) Significant effects previously examined will be substantially more severe than shown in the previous EIR;
> >
> > (C) Mitigation measures or alternatives previously found not to be feasible would in fact be feasible and would substantially reduce one or more significant effects of the project, but the project proponents decline to adopt the mitigation measure or alternative; or
> >
> > (D) Mitigation measures or alternatives which are considerably different from those analyzed in the previous EIR would substantially reduce one or more

significant effects on the environment, but the project proponents decline to adopt the mitigation measure or alternative.

(CEQA Guidelines § 15162(a).)

148. If an agency is faced with a new discretionary decision after a project has been approved, the agency must consider whether any of the conditions set forth in CEQA Guidelines section 15162(a) apply, and if so, the agency must prepare a subsequent EIR. (CEQA Guidelines § 15162(c).)

FIRST CAUSE OF ACTION

Violation of the Federal PSA — Failure to Provide a Public Process

(Code Civ. Proc., § 1085; 49 U.S.C. § 60118(d))

149. Petitioners hereby incorporate by reference each and every allegation set forth above.

150. 49 U.S.C. section 60118(d), which incorporates the standards and procedures outlined in section 60118(c), imposed a mandatory and nondiscretionary duty on OSFM to provide the public with "notice and an opportunity for a hearing" prior to granting the State Waivers for CA-324 and CA-325. (49 U.S.C. § 60118(c), (d).)

151. Prior to granting the State Waivers, OSFM did not provide any cognizable public process. OSFM did not provide formal notice to the public of its intent to consider the State Waiver applications; did not invite or consider public comment on the applications; and did not provide the public with any opportunity for a hearing. In fact, OSFM did not even make the State Waiver applications publicly available prior to granting the Waivers, despite repeated requests from the public to do so.

152. Thus, OSFM violated its mandatory and nondiscretionary duty under the Federal PSA to provide the public with notice and an opportunity for a hearing.

153. The State Waivers for both CA-324 and CA-325 became final and effective on February 11, 2025, when PHMSA notified OSFM that it would not object to either State Waiver. Thus, each State Waiver constitutes a final agency action that is ripe for judicial review.

154. Petitioners have performed all conditions precedent to filing this action and have exhausted all available remedies to the extent required by law. Petitioners do not have a plain, speedy, or adequate remedy at law other than mandamus relief, and they depend on the Court granting the relief

requested herein to require OSFM to satisfy its obligations under the Federal PSA. (*See* Code Civ. Proc., § 1086.)

155. In their capacity as members of the public interested in ensuring agency compliance with laws, regulations, and guidance concerning pipeline safety and the preservation of public health and natural resources, Petitioners had a beneficial right to performance of OSFM's duties. (*See* Cal. Const. arts. I, §§ 1, 3(a); Code Civ. Proc., § 1085.)

<u>SECOND CAUSE OF ACTION</u>

Violation of the Federal PSA — Failure to Provide a Statement of Reasons

(Code Civ. Proc., § 1085; 49 U.S.C. § 60118(d))

156. Petitioners hereby incorporate by reference each and every allegation set forth above.

157. 49 U.S.C. section 60118(d), which incorporates the standards and procedures outlined in section 60118(c), imposed a mandatory and nondiscretionary duty on OSFM to, for each State Waiver, "state . . . the reasons for granting the [W]aiver." (49 U.S.C. § 60118(c), (d).)

158. Each State Waiver includes, in its entirety, the following: a perfunctory recital of Sable's requests, a statement of OSFM's regulatory jurisdiction, and the scope and conditions of each approved Waiver. But neither Waiver provides *any* justification, supporting analysis, or reasons for OSFM's decision to grant the Waiver. On information and belief, OSFM did not issue any other letter, order, or document in approving the Waivers that included a statement of reasons for its decision.

159. Thus, OSFM violated its mandatory and nondiscretionary duties under the Federal PSA to provide, for each State Waiver, a statement of reasons for granting the Waiver.

160. The State Waivers for both CA-324 and CA-325 became final and effective on February 11, 2025, when PHMSA notified OSFM that it would not object to either State Waiver. Thus, each State Waiver constitutes a final agency action that is ripe for judicial review.

161. Petitioners have performed all conditions precedent to filing this action and have exhausted all available remedies to the extent required by law. Petitioners do not have a plain, speedy, or adequate remedy at law other than mandamus relief, and they depend on the Court granting the relief requested herein to require OSFM to satisfy its obligations under the Federal PSA. (*See* Code Civ. Proc., § 1086.)

162. In their capacity as members of the public interested in ensuring agency compliance with laws, regulations, and guidance concerning pipeline safety and the preservation of public health and natural resources, Petitioners had a beneficial right to performance of OSFM's duties. (*See* Cal. Const. arts. I, §§ 1, 3(a); Code Civ. Proc., § 1085.)

THIRD CAUSE OF ACTION

Declaratory Relief — State Waiver Procedures Required under the Federal PSA

(Code Civ. Proc., § 1060; 49 U.S.C. § 60118(d))

163. Petitioners hereby incorporate by reference each and every allegation set forth above.

164. As noted, OSFM did not offer any cognizable public process before granting the State Waivers, and, on information and belief, has a pattern and practice of granting such waivers without providing the public with notice, an opportunity for a hearing, or a statement of reasons for its decision, as required by the Federal PSA.

165. An actual controversy has arisen and now exists between Petitioners, on the one hand, and OSFM, on the other hand, relative to their respective rights and duties as it relates to Petitioners' request that OSFM provide a public process before approving Sable's State Waiver applications.

166. Petitioners seek a judicial determination regarding the scope of OSFM's obligations under the Federal PSA. Petitioners seek a declaration that, in granting a State Waiver, OSFM must comply with same standards and procedures that the Secretary of Transportation must adhere to in granting a waiver under 49 U.S.C. section 60118(c), including providing the public with notice, an opportunity for a hearing, and a statement of reasons.

FOURTH CAUSE OF ACTION

Abuse of Discretion under the Federal PSA

(Code Civ. Proc., § 1094.5; 49 U.S.C. § 60118(d))

167. Petitioners hereby incorporate by reference each and every allegation set forth above.

168. The State Waivers for CA-324 and CA-325 constitute final administrative decisions that were quasi-judicial in nature.

169. Code of Civil Procedure section 1094.5 permits judicial review of quasi-judicial administrative decisions. In reviewing a quasi-judicial decision, the court considers, in part, "whether

there was any prejudicial abuse of discretion." (Code Civ. Proc., § 1094.5(b).) "Abuse of discretion is established if the respondent has not proceeded in the manner required by law, the order or decision is not supported by the findings, or the findings are not supported by evidence." (*Id.*)

170. As a matter of procedure, OSFM abused its discretion by failing to comply with the mandatory State Waiver procedures outlined in the Federal PSA, as explained in Petitioners' First and Second Causes of Action.

171. As to the merits of OSFM's decisions, the Federal PSA only allows a State Waiver to be granted if the relevant state authority "determines that the waiver is not inconsistent with pipeline safety." (49 U.S.C. § 60118(c)(1)(A), (d).) OSFM has consistently construed this standard to mean that a State Waiver can only be granted where the operator's "proposed alternative measures can provide an equal or greater level of safety than the required regulation." (*Pathways for Restarting Pipelines*, OSFM, https://osfm.fire.ca.gov/what-we-do/pipeline-safety-and-cupa/pathways-for-restarting-pipelines.) In other words, as OSFM has also put it, the proposed alternative measures must ensure the pipeline will be "as safe or safer" than if it was in compliance.

172. As discussed above, OSFM did not provide any analysis in support of its decisions to grant the State Waivers. Nor, relatedly, did it make any specific findings as to why the conditions of the Waivers would ensure that CA-324 and CA-325 are "as safe or safer" than if they had effective cathodic protection, or complied with 49 C.F.R. § 195.452(h)(4)(iii)(H). In fact, neither Waiver even referenced the applicable State Waiver standard in the Federal PSA, making it impossible to determine whether OSFM applied the appropriate legal standard in its review.

173. By failing to provide *any* findings in support of its decisions, OSFM abused its discretion. (*See Topanga Assn. for a Scenic Comm. V. County of Los Angeles* (1974) 11 Cal.3d 506, 515 ("[I]mplicit in [Code of Civil Procedure] section 1094.5 is a requirement that the agency which renders the challenged decision must set forth findings to bridge the analytic gap between the raw evidence and ultimate decision or order.").)

174. Moreover, even a cursory review of the State Waivers reveals that they are patently inadequate to address the defects in the Las Flores Pipeline System and, ultimately, fail to ensure that CA-324 and CA-325 will be "as safe or safer" than if they complied with all applicable regulations.

175. First, as noted above, the fundamental logic underpinning the State Waivers is flawed from the start. The Waivers allow Sable to replace effective cathodic protection, which prevents corrosion from occurring in the first place, with something akin to an enhanced management program. Indeed, instead of *proactively* preventing corrosion with proven technology, the Waivers require only that the operator *reactively* track down and remediate the incessant corrosion of the pipelines, primarily by using ILI tools.

176. You do not have to be a pipeline safety expert to see that the management program contemplated by the Waivers, which *allows* the progressive corrosion of the Las Flores Pipeline System to continue, is not, by any measure, as safe as preventing corrosion in the first place.

177. Second, we have already seen the shortcomings of the risk management measures on which the Waivers rely. As discussed, the failure of ILI tools was a contributing factor to the Refugio Oil Spill. Plains periodically conducted ILI inspections of the Las Flores Pipeline System, but the results of those inspections were often erroneous, and they failed to accurately detect the anomaly that ultimately caused the rupture in CA-324. With the real possibility that anomalies are undercalled or go unnoticed, effective cathodic protection is the only way to ensure the Las Flores Pipeline System does not again corrode to the point of rupture.

178. Third, and compounding that concern, OSFM has failed to consider Sable's operational capacity. The management program outlined in the Waivers puts an enormous amount of faith in the operator's capacity to properly and timely run ILI tools, review the results of the ILI surveys, precisely locate corrosion anomalies, and properly repair them. But there is no indication that Sable merits such trust. Sable is a new, speculative entity that has never actually operated an active oil and gas facility. And all it has affirmatively demonstrated is a propensity to cut regulatory corners.

179. Fourth, the Waivers only consider the risk of corrosion under insulation ("CUI"). While CUI is certainly an issue on the Las Flores Pipeline System, it is only one of many corrosion threats that the pipelines are vulnerable to without effective cathodic protection.

180. As previously discussed, the pipelines' heavy shielding, tape barrier, vintage and type of coating, operating temperature, and surrounding environment all work in concert to create external corrosion in various forms. Such external corrosion falls into four general categories: (1) wall loss or

thinning, (2) cracking or crack-like corrosion, (3) pitting, and (4) corrosion within dents. The latter two forms of corrosion are especially difficult to identify via ILI tools, and almost impossible to reliably predict when it comes to estimating failure. The Waivers do not address these threats.

181. Fifth, while the Waivers require hydrotesting of CA-324 and CA-325A before they return to service, they inexplicably exclude CA-325B. Without a hydrotest, OSFM cannot assure that previously-identified anomalies on CA-325B have been properly repaired.

182. Sixth, and relatedly, the parameters for the hydrotest of CA-324, including the pressure within the line, are insufficient to accurately test CA-324's integrity.

183. Seventh, the Waivers do not require critical corrosion tracking that can inform an operator of corrosion "hot spots" along the pipeline system and sites where there may be interactive threats, like general wall loss in combination with cracking corrosion. Given the pipelines' history of pervasive corrosion, separately identifying and plotting corrosion indications by type, severity, and approximate milepost is a necessary step towards ensuring their safety.

184. The above list is representative of why the Waivers fail to ensure that the Las Flores Pipeline System will be "as safe or safer" as if it complied with all applicable regulations, but it is non-exhaustive. Petitioners' review of the Waivers is ongoing, and, as OSFM releases more pertinent documents, Petitioners and their retained expert(s) will likely identify additional deficiencies with the Waivers.

185. In sum, the Waivers represent an astonishing lapse of judgment in an agency that is charged with overseeing pipeline safety, made worse by the fact that OSFM provided no public process or justification for its decisions. Because (1) OSFM failed to comply with the mandatory State Waiver procedures outlined in the Federal PSA, (2) OSFM failed to provide *any* findings in support of its decisions, and (3) the State Waivers, by any measure, fail to ensure the Las Flores Pipeline System will be as safe or safer than if it complied with all applicable regulations, OSFM prejudicially abused its discretion in issuing the Waivers, warranting administrative mandamus relief. (Code Civ. Proc., § 1094.5(b).)

186. Petitioners have performed all conditions precedent to filing this action and have exhausted all available remedies to the extent required by law. Petitioners do not have a plain, speedy, or

adequate remedy at law other than mandamus relief.

187. In their capacity as members of the public interested in ensuring agency compliance with laws, regulations, and guidance concerning pipeline safety and the preservation of public health and natural resources, Petitioners are beneficially interested in OSFM's decisions on Sable's State Waiver applications.

FIFTH CAUSE OF ACTION

Violation of the State PSA — Failure to Provide a Discussion of Significant Factors

(Code Civ. Proc., § 1085; Gov. Code, § 51011(c))

188. Petitioners hereby incorporate by reference each and every allegation set forth above.

189. The Las Flores Pipeline System is subject to the State PSA and the regulations adopted thereunder, which are codified at Title 19 of the California Code of Regulations, section 2000 *et seq*. (*See* Gov. Code, § 51010.5(a).)

190. Government Code section 51011 allows the State Fire Marshal to "exempt the application of regulations adopted pursuant to [the State PSA]." (Gov. Code, 51011(b).) However, should the State Fire Marshal grant such an exemption, Government Code section 51011 imposes a mandatory and nondiscretionary duty to "include a discussion of those factors that the State Fire Marshal consider[ed] significant to the granting of the exemption." (Gov. Code, § 51011(c).)

191. The waivers that OSFM issued for CA-324 and CA-325 function, incontrovertibly, as State Waivers for purposes of the Federal PSA. But they also constitute "exemptions" under the State PSA, as they effectively excuse compliance with "regulations adopted pursuant to [the State PSA]." (Gov. Code, § 51011(b).) Specifically, and as noted in the Waivers themselves, they excuse Sable from fully complying with Title 19 of the California Code of Regulations, section 2000, which incorporates by reference Part 195's federal minimum safety standards.

192. Thus, in addition to the standards and procedures for waivers required by the Federal PSA, Respondents had a concurrent obligation to comply with the more onerous waiver/exemption requirements required by the State PSA. Accordingly, in granting the State Waivers, Respondents had a mandatory and nondiscretionary duty to, for each Waiver, include in its decision a discussion of factors significant to the decision. (Gov. Code, § 51011(c).)

193. As discussed above in Petitioners' Second Cause of Action, in issuing the State Waivers, neither OSFM nor the State Fire Marshal provided *any* justification, supporting analysis, or reasons for its decision. Nor did they otherwise provide "a discussion of factors that the State Fire Marshal consider[ed] significant" to the decision. (Gov. Code, § 51011(c).)

194. Thus, Respondents violated their mandatory and nondiscretionary duties under the State PSA to provide, for each Waiver, a discussion of the factors they considered significant to the decision.

195. The Waivers (and "exemptions") for both CA-324 and CA-325 became final and effective on February 11, 2025. Thus, each State Waiver constitutes a final agency action that is ripe for judicial review.

196. Petitioners have performed all conditions precedent to filing this action and have exhausted all available remedies to the extent required by law. Petitioners do not have a plain, speedy, or adequate remedy at law other than mandamus relief, and they depend on the Court granting the relief requested herein to require Respondents to satisfy their obligations under the State PSA. (*See* Code Civ. Proc., § 1086.)

197. In their capacity as members of the public interested in ensuring agency compliance with laws, regulations, and guidance concerning pipeline safety and the preservation of public health and natural resources, Petitioners had a beneficial right to performance of Respondents' duties. (*See* Cal. Const. arts. I, §§ 1, 3(a); Code Civ. Proc., § 1085.)

SIXTH CAUSE OF ACTION

Abuse of Discretion under the State PSA

(Code Civ. Proc., § 1094.5; Gov. Code, § 51011(b))

198. Petitioners hereby incorporate by reference each and every allegation set forth above.

199. The State Waivers for CA-324 and CA-325 constitute final administrative decisions that were quasi-judicial in nature.

200. Code of Civil Procedure section 1094.5 permits judicial review of quasi-judicial administrative decisions. In reviewing a quasi-judicial decision, the court considers, in part, "whether there was any prejudicial abuse of discretion." (Code Civ. Proc., § 1094.5(b).) "Abuse of discretion is established if the respondent has not proceeded in the manner required by law, the order or decision is

not supported by the findings, or the findings are not supported by evidence." (*Id.*)

201. The State PSA only allows the State Fire Marshal to "exempt the application of regulations adopted pursuant to [the State PSA] . . . when it is determined that the risk to public safety is slight and the probability of injury or damage remote." (Gov. Code, § 51011(b).)

202. As discussed above, neither OSFM nor the State Fire Marshal provided any analysis in support of its decisions to grant the State Waivers. Nor, relatedly, did either expressly determine that the risk of the Waivers to public safety is slight and the probability of injury or damage remote, suggesting that they failed to properly consider and apply Government Code section 51011(b). Nor did OSFM or the State Fire Marshal make any specific findings to support such a determination. For that reason alone, approval of the waivers constitutes an abuse of discretion. (*See Topanga Assn. for a Scenic Comm. V. County of Los Angeles* (1974) 11 Cal.3d 506, 515 ("[I]mplicit in [Code of Civil Procedure] section 1094.5 is a requirement that the agency which renders the challenged decision must set forth findings to bridge the analytic gap between the raw evidence and ultimate decision or order.").)

203. Moreover, for the same reasons that the Waivers failed to meet the Federal PSA standard — outlined above in Petitioners' Third Cause of Action — they failed to meet the more onerous standard imposed by the State PSA.

204. Indeed, the risk of a rupture from the Las Flores Pipeline System is not merely hypothetical; it has already caused one of the worst oil spill disasters in California history. The Waivers would allow Sable — a speculative company — to resurrect the pipeline system without correcting or adequately addressing the fundamental design defect that caused the 2015 spill. Should Sable proceed under the Waivers, another spill is not just possible, but according to one independent analysis, likely. And the 120-mile long Las Flores Pipeline System — which passes through a suburban neighborhood, a number of popular recreation areas, and critical sources of water for inland communities — poses a substantial and direct threat to public safety.

205. Because the State Fire Marshal did not — and cannot — determine that the risk of the Waivers to public safety is slight and the probability of injury or damage remote, the Waivers constitute a prejudicial abuse of discretion, warranting administrative mandamus relief. (Code Civ. Proc., § 1094.5(b).)

206. Petitioners have performed all conditions precedent to filing this action and have exhausted all available remedies to the extent required by law. Petitioners do not have a plain, speedy, or adequate remedy at law other than mandamus relief.

207. In their capacity as members of the public interested in ensuring agency compliance with laws, regulations, and guidance concerning pipeline safety and the preservation of public health and natural resources, Petitioners are beneficially interested in the State Fire Marshal's decisions on Sable's State Waiver applications.

SEVENTH CAUSE OF ACTION

Declaratory Relief — Standards and Procedures Required under the State PSA

(Code Civ. Proc., § 1060; Gov. Code, § 51011(b), (c))

208. Petitioners hereby incorporate by reference each and every allegation set forth above.

209. As noted, in granting the State Waivers, Respondents apparently did not consider the relevant requirements of the State PSA. Specifically, Respondents apparently ignored the standard set forth in Government Code section 51011(b). And they failed to provide a discussion of factors that were significant to the decisions to grant the waivers, as required by Government Code section 51011(c).

210. On information and belief, Respondents have a pattern and practice of granting State Waivers that effectively exempt compliance with state regulations without complying with, or even considering, the relevant requirements of the State PSA.

211. An actual controversy has arisen and now exists between Petitioners, on the one hand, and OSFM, on the other hand, relative to their respective rights and duties.

212. Petitioners seek a judicial determination regarding the scope of Respondents' obligations under the State PSA when issuing a State Waiver that effectively exempts an operator from compliance with state regulations. Petitioners seek a declaration that, in granting such a State Waiver, Respondents must comply with Government Code section 51011, including by considering a requested waiver under the standard set forth in Section 51011(b), and providing a discussion of factors significant to the decision to grant the waiver.

EIGHTH CAUSE OF ACTION

CEQA — Failure to Prepare a Subsequent EIR

(Code Civ. Proc., § 1085; Pub. Res. Code, § 21166 ; 14 Cal. Code Regs. § 15162)

213. Petitioners hereby incorporate by reference each and every allegation set forth above.

214. Sable's applications for State Waivers required approval by OSFM. OSFM had the discretion whether to grant the requested Waivers, and if so, on what terms. (*See* 49 U.S.C. § 60118(c), (d); Gov. Code, § 51011(b).)

215. Because discretionary approval by OSFM was required, the agency needed to determine whether any of the criteria set forth in Public Resources Code section 21166 and CEQA Guidelines section 15162(a) applied. (*See* CEQA Guidelines § 15162(c).) On information and belief, OSFM failed to even consider these three criteria, in violation of CEQA. However, all three apply here.

216. First, substantial changes are proposed in the project which require major revisions of the 1985 EIR/EIS.

217. The original project was proposed as an oil and gas pipeline system that would be protected, in its entirety, by cathodic protection. The 1985 EIR/EIS relied on this project description when it evaluated the potential impacts of the project, and its analysis assumed that the pipelines' cathodic protection system would be "very effective" at reducing the probability of an oil spill.

218. Now, however, Sable, via the Waivers, is proposing to operate the pipelines without effective cathodic protection, potentially increasing the risk of a spill as much as five times.

219. Additionally, the lack of effective cathodic protection will necessitate more excavations to check for and respond to anomalies, and such excavations are required by the Waivers to be conducted on a regular basis. These excavations, which were not contemplated in the 1985 EIR/EIS, will increase potential impacts to sensitive resources along the 120-mile pipeline route, including rivers, streams and wetlands; environmentally sensitive habitats; rare, endangered, and threatened species; and cultural resources.

220. Thus, operating without effective cathodic protection, and under the conditions imposed by the Waivers, constitutes a substantial change in the project that increases the risk and severity of impacts and requires major revisions to the 1985 EIR/EIS. Accordingly, OSFM must prepare a subsequent EIR. (CEQA Guidelines § 15162(a)(1).)

221. Second, the failure of the pipelines' cathodic protection system and resulting corrosion

constitutes a change in circumstances that requires a subsequent EIR. As discussed, without effective cathodic protection, the pipeline is vulnerable to pervasive, continuous, and progressive corrosion that was not accounted for in the 1985 EIR/EIS. This changed circumstance increases the risk and severity of potential oil spill-related impacts, and thus requires preparation of a subsequent EIR. (CEQA Guidelines § 15162(a)(2).)

222. Third, it was only after the 2015 spill that the Las Flores Pipeline System was discovered to lack effective cathodic protection. This new information, which shows that the risk of an oil spill is substantially more severe than previously determined, could not have been known with the exercise of reasonable due diligence when the 1985 EIR/EIS was certified thirty-one years earlier. As to buried, insulated lines more generally, no formal report existed as to the ineffectiveness of cathodic protection prior to an industry analysis published by NACE in 1992 — seven years after certification of the 1985 EIR/EIS.

223. Accordingly, that cathodic protection is ineffective on the Las Flores Pipeline System constitutes new information that was not known, and could not have been known, when the previous EIR/EIS was certified. Thus, OSFM is required to prepare a subsequent EIR to ensure an adequate analysis of the potential impacts of operating the Las Flores Pipeline System without effective cathodic protection. (CEQA Guidelines, § 15162(a)(3).)

224. OSFM failed to comply with CEQA when it approved the State Waivers without preparing a subsequent EIR.

225. On April 11, 2025, Petitioners served a Notice of Commencement of Action on Respondents pursuant to Public Resources Code section 21167.5. The Notice is attached hereto as **Exhibit I**.

226. Petitioners have performed all conditions precedent to filing this action and have exhausted all available remedies to the extent required by law. Petitioners do not have a plain, speedy, or adequate remedy at law other than mandamus relief, and they depend on the Court granting the relief requested herein to require OSFM to satisfy its obligations under CEQA. (*See* Code Civ. Proc., § 1086.)

227. In their capacity as members of the public interested in ensuring agency compliance with laws, regulations, and guidance concerning pipeline safety and the preservation of public health and

natural resources, Petitioners had a beneficial right to performance of OSFM's duties. (*See* Cal. Const. arts. I, §§ 1, 3(a); Code Civ. Proc., § 1085.)

PRAYER FOR RELIEF

WHEREFORE, Petitioners pray as follows:

1. That the Court immediately, and on an *ex parte* basis, issue a temporary stay of OSFM's approval of the State Waivers, pending completion of judicial review, pursuant to Code Civ. Proc., § 1094.5(g) and Rule 3.1202(c) of the California Rules of Court;
2. That the Court issue temporary, preliminary, and permanent injunctive relief preventing restart of the Las Flores Pipeline System under the State Waivers;
3. That the Court issue a peremptory writ of mandate directing CalFIRE, by and through OSFM, to set aside and vacate its approval of the State Waiver for CA-324;
4. That the Court issue a peremptory writ of mandate directing CalFIRE, by and through OSFM, to set aside and vacate its approval of the State Waiver for CA-325;
5. That the Court issue a peremptory writ of mandate directing Respondents, should they reconsider Sable's State Waiver applications, to:
   a. prepare a subsequent EIR that considers the potential impacts of operating the Las Flores Pipeline System without effective cathodic protection, without complying with 49 C.F.R. § 195.452(h)(4)(iii)(H), and under the conditions of the proposed State Waivers;
   b. conduct any other procedures that the Court deems necessary and/or appropriate under CEQA;
   c. provide the public with notice and an opportunity for a hearing before granting a State Waiver for either CA-324 or CA-325, as required by the Federal PSA;
   d. in granting a State Waiver for either CA-324 or CA-325, provide a statement of reasons, as required by the Federal PSA; and
   e. in granting a State Waiver for either CA-324 or CA-325, provide a discussion of factors significant to its decision, as required by the State PSA;
6. That the Court issue the specific additional declaratory relief prayed for in Petitioners'

Third and Seventh Causes of Action;

7. That Petitioners be awarded attorneys' fees and costs pursuant to Sections 1021.5 and 1032(b) of the Code of Civil Procedure, and any other applicable law; and

8. For such other and further relief as the Court deems just and proper.

Dated: April 15, 2025

Respectfully submitted,

ENVIRONMENTAL DEFENSE CENTER

By: Ldakp

LINDA KROP
JEREMY M. FRANKEL
TARA C. RENGIFO
Attorneys for Petitioners and Plaintiffs

VERIFICATION

I, the undersigned, declare:

I am the Executive Director of Environmental Defense Center, a Petitioner in this action, and am authorized to make this verification for an on its behalf. I have read the foregoing Petition for Writ of Mandate and Complaint for Declaratory and Injunctive Relief ("Petition") and know its contents. The facts alleged in the above Petition are true of my own knowledge except as to those matters which are stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct. This declaration was executed on April 11, 2025, in Santa Barbara, California.

Alex Katz

Alex Katz
Executive Director
Environmental Defense Center

VERIFICATION

I, the undersigned, declare:

I am the President of Get Oil Out!, a Petitioner in this action, and am authorized to make this verification for an on its behalf. I have read the foregoing Petition for Writ of Mandate and Complaint for Declaratory and Injunctive Relief ("Petition") and know its contents. The facts alleged in the above Petition are true of my own knowledge except as to those matters which are stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct. This declaration was executed on April 10, 2025 in Santa Barbara, California.

Michael T. Lyons
President
Get Oil Out!

VERIFICATION

I, the undersigned, declare:

I am the Executive Director of Santa Barbara County Action Network, a Petitioner in this action, and am authorized to make this verification for an on its behalf. I have read the foregoing Petition for Writ of Mandate and Complaint for Declaratory and Injunctive Relief ("Petition") and know its contents. The facts alleged in the above Petition are true of my own knowledge except as to those matters which are stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct. This declaration was executed on 4-11-25, in Santa Maria, California.

K. Hough

Ken Hough
Executive Director
Santa Barbara County Action Network

VERIFICATION

I, the undersigned, declare:

I, Maureen Ellenberger, am the Santa Barbara/Ventura Chapter Chair of Sierra Club, a Petitioner in this action, and I have been authorized to make this verification on behalf of Sierra Club. I have read the foregoing Petition for Writ of Mandate and Complaint for Declaratory and Injunctive Relief ("Petition") and know its contents. The facts alleged in the above Petition are true of my own knowledge except as to those matters which are stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct. This declaration was executed on 4/09/25, in Santa Barbara, California.

Maureen Ellenberger
Maureen Ellenberger
Santa Barbara/Ventura Chapter Chair
Sierra Club

VERIFICATION

I, the undersigned, declare:

I am the Executive Director of Santa Barbara Channelkeeper, a Petitioner in this action, and am authorized to make this verification for an on its behalf. I have read the foregoing Petition for Writ of Mandate and Complaint for Declaratory and Injunctive Relief ("Petition") and know its contents. The facts alleged in the above Petition are true of my own knowledge except as to those matters which are stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct. This declaration was executed on April 10, 2015, in Santa Barbara, California.

Walter Edward Morton

Walter Edward Morton
Executive Director
Santa Barbara Channelkeeper

EXHIBIT A

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.

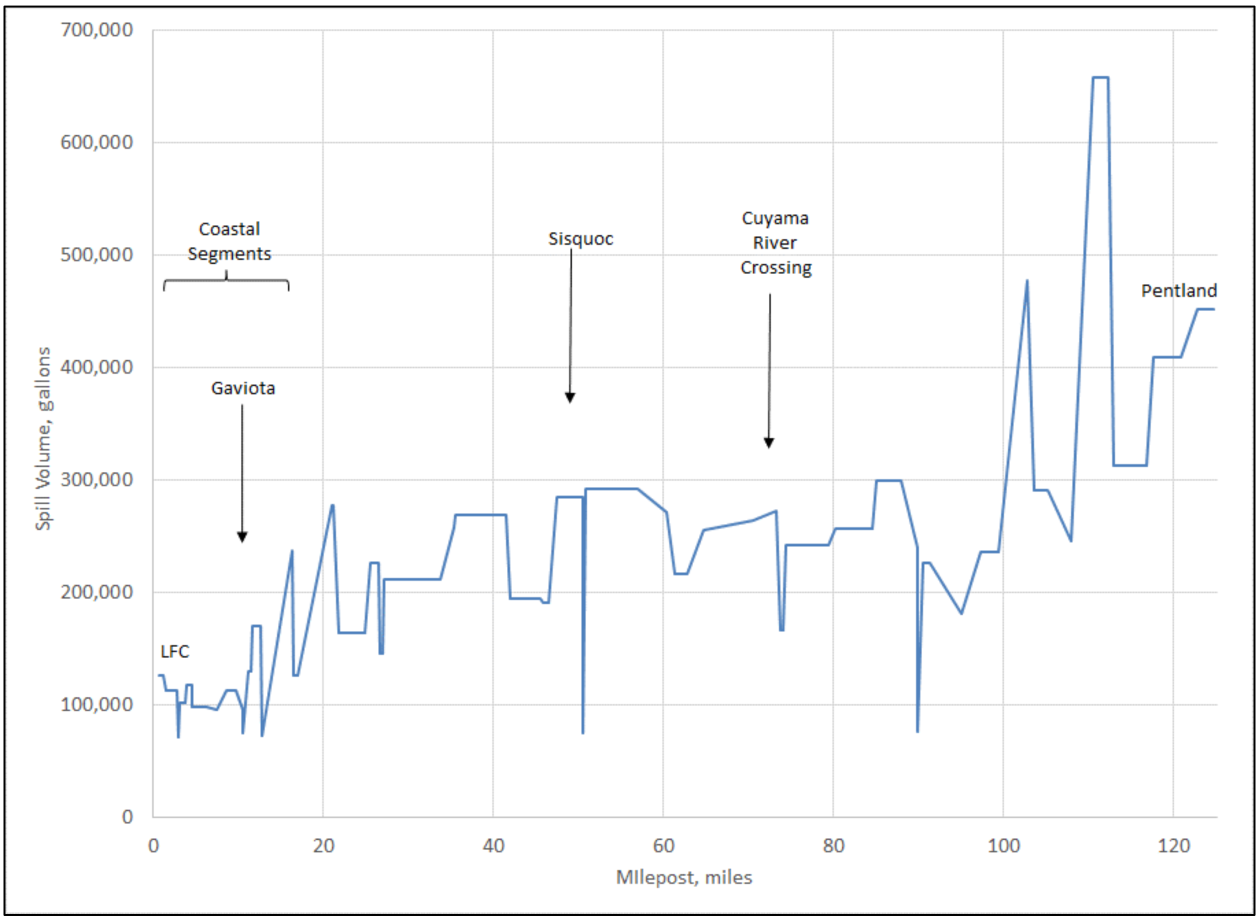
Crude Pipeline Spill Volumes

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.

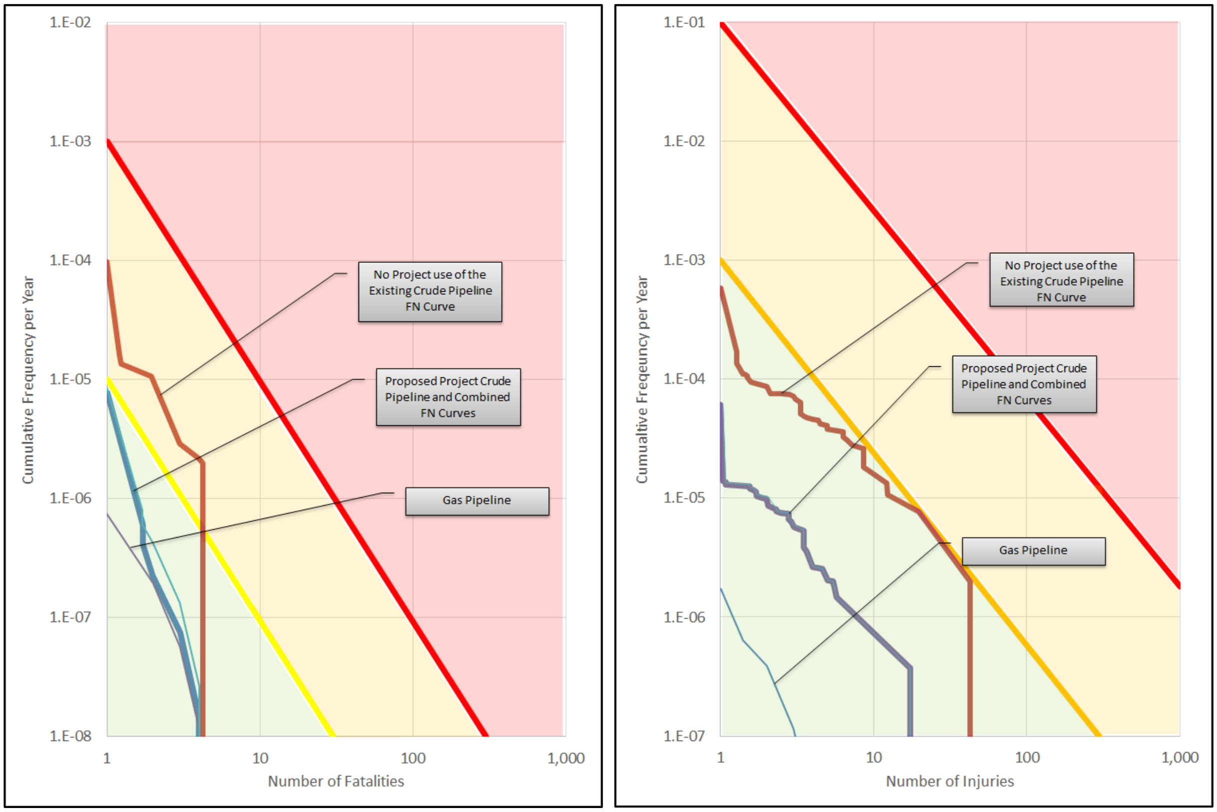
Gas Pipeline

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

EXHIBIT B

SABLE
OFFSHORE

April 24, 2024

Chief Jim Hosler
CAL FIRE – Office of the State Fire Marshal
Chief of Pipeline Safety and CUPA Programs
Pipeline Safety
3780 Kilroy Airport Way, Suite 500
Long Beach, CA 90806

RE: Pacific Pipeline Company (operated by Sable Offshore Corp., OPID #40851)
State Waiver Applications for:
Las Flores Pipeline CA-324 (OSFM #0015)
Las Flores Pipeline CA-325A/B (OSFM #0001)

Chief Hosler,

As you are aware, Sable Offshore Corp. purchased exclusive ownership of the shares in Pacific Pipeline Company, owner of the Las Flores Pipeline, from ExxonMobil affiliate Mobil Pacific Pipeline Company, at which point Pacific Pipeline Company became a wholly owned subsidiary of Sable Offshore Corp. Subsequent to its acquisition, Sable Offshore Corp. filed for and received an OPID from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (OPID #40851) to be named operator of the Las Flores Pipeline system.

This letter serves to confirm Sable Offshore Corp.'s intention to continue pursuit of the referenced State Waiver Applications submitted by Pacific Pipeline Company on July 10, 2023.

Please update your office's records to reflect the new contact information for Pacific Pipeline Company as applicant and Sable Offshore Corp. as operator to be:

Pacific Pipeline Company
Sable Offshore Corp. (Operator ID #40851)
845 Texas Ave. Suite 2920
Houston, TX 77002
lyearwood@sableoffshore.com

If you have any questions, or require anything further, please do not hesitate to contact me at (832) 434-9461.

Sincerely,

Lance Yearwood
Vice President
Sable Offshore Corp.

Pacific Pipeline Company
22777 Springwoods Village Parkway
Spring, Texas 77389

PACIFIC PIPELINE COMPANY

July 10, 2023

VIA ELECTRONIC MAIL

James Hosler
Assistant Deputy Director
Chief of Pipeline Safety and CUPA Programs
Department of Forestry and Fire Protection
Office of the State Fire Marshal
Pipeline Safety Division

3780 Kilroy Way, Suite 500
Long Beach, California 90806

Subject: Pacific Pipeline Company (OPID #40475) State Waiver Application for the *Las Flores Pipeline CA-324 (OSFM #0015)*

Dear Mr. Hosler:

Pacific Pipeline Company ("PPC") requests a ten-year State Waiver from the Office of the State Fire Marshal ("OSFM") for the intrastate pipeline segment CA-324 (formerly Line 901) to comply with Civil Action No. 2:20-CV-02415 Consent Decree, DOJ Case #90-5-1-1-1130, pursuant to Appendix B, Article I(1)A. Within the State Waiver, PPC also requests relief from the requirements to evaluate and remediate all corrosion of or along longitudinal seam welds per 49 C.F.R. § 195.452(h)(4)(iii)(H). (Collectively, the "Application").

Please note, the Application contains confidential information that is exempt from disclosure under the California Public Records Act (PRA), the Freedom of Information Act (FOIA), and other laws including, but not limited to, Gov't Code § 7927.705, § 7927.500, 5 U.S.C. § 552(b)(3), (4), (6), 6 U.S.C. § 133, and 6 U.S.C. § 1207-1208. The submission also contains information that constitutes homeland security and critical infrastructure information that should be protected from public disclosure. If OSFM does not concur that the information contained herein is exempt from disclosure, PPC hereby respectfully requests that OSFM contact me and our legal counsel, Rebekah Bennett (copied here) to discuss the matter and appropriate next steps. PPC also requests OSFM to notify PPC if OSFM intends to provide copies of any of the enclosed materials to other public agencies (including those agencies that are parties to the Consent Decree) so that PPC and OSFM can further discuss and coordinate procedures to protect confidential information from public disclosure. If OSFM subsequently receives a PRA request that seeks disclosure of the Application, PPC requests advance notice and the opportunity to contest any production of any confidential information to third parties.

The following information is provided as part of the State Waiver application:

---

(1) The name, mailing address, and telephone number of the applicant and whether the applicant is an operator;

Pacific Pipeline Company (Operator ID #40475)
Attn: Diana Skates, Pipeline Safety Advisor
22777 Springwoods Village Pkwy
Spring, TX 77389
diana.r.skates@exxonmobil.com

(2) A detailed description of the pipeline facilities for which the special permit is sought, including:

(i) The beginning and ending points of the pipeline mileage to be covered and the Counties and States in which it is located;

A State Waiver is sought for a segment of the Las Flores Pipeline system, identified under trunk line CA-324 (formerly Line 901). Table 1 summarizes relevant information. A map of the pipeline system is included as ***Attachment A*** and further details about the pipeline are included in ***Attachment B***.

Table 1: Pipelines Applicable to State Waiver Application

System Name	Line ID	Line Designation	Location	Mileage	California County
Las Flores Pipeline	0015	CA-324	Las Flores Canyon to Gaviota 34.478915°, -120.041783° 34.476081°, -120.198142°	10.86	Santa Barbara

(ii) Whether the pipeline is interstate or intrastate and a general description of the right-of-way including proximity of the affected segments to populated areas and unusually sensitive areas;

The Las Flores Pipeline is a common carrier intrastate pipeline. CA-324 has potential to impact High Consequence Areas, including unusually sensitive areas. A map of the pipeline system is included as ***Attachment A*** and further details about the pipeline and its right-of-way are included in ***Attachment B***.

(iii) Relevant pipeline design and construction information including the year of installation, the material, grade, diameter, wall thickness, and coating type;

The Las Flores Pipeline CA-324 was constructed in 1990, hydrostatically tested in November 1990, and placed into crude oil service in 1992. The Las Flores Pipeline is specifically designed and permitted to transport outer continental shelf (OCS) and other locally produced onshore and offshore petroleum from the Santa Barbara and Santa Maria Basins.

Additional, relevant, design and construction information is summarized in ***Attachment B.***

(iv) Relevant operating information including operating, leak history, and most recent testing or assessment results;

Operating Information
The pipeline transported crude oil in continuous service from its initial commissioning until 2015. CA-324 has not transported crude oil since May 19, 2015. Information related to historic operations and continued operating information upon resuming transportation of crude oil is included in ***Attachment B***.

Leak History
Prior to May 19, 2015, there were no releases from CA-324 pipeline which met reportable criteria. On May 19, 2015, CA-324 (formerly Line 901) experienced a release on a section of buried pipe. PHMSA's Failure Investigation Report (May 2016) attributed the rupture of the pipeline to "progressive external corrosion of the insulated, 24-inch diameter steel pipeline." PHMSA's findings indicate that the direct cause of the Line 901 failure was external corrosion that thinned the pipe wall to a level where it ruptured suddenly and released crude oil. PHMSA's investigation identified the following categories of contributory causes:

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 the Operator 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.

Subsequently, PHMSA issued a Corrective Action Orders (CAOs) to the Operator identifying additional findings. The Operator responded to PHMSA's CAOs and on October 14, 2020, a Consent Decree was entered by the United States District Court for the Central District of California. Pursuant to Section X of the Consent Decree, the CAOs issued by PHMSA were closed and all remaining obligations of the CAOs became part of the Consent Decree. Hence, the Consent Decree is the document governing the particular requirements and obligations of the Operator to resume crude oil transportation in the pipeline, including the requirement for a State Waiver. In October 2022, PPC acquired the pipeline asset and assumed certain obligations of the Consent Decree that transferred with the asset, including the requirement for a State Waiver for the Las Flores Pipeline.

Assessment Results
Assessment results are included in ***Attachment B.***

(3) A list of the specific regulation(s) from which the applicant seeks relief;

1. Pacific Pipeline Company is seeking to comply with Civil Action No. 2:20-CV-02415 Consent Decree, DOJ Case #90-5-1-1-1130, pursuant to Appendix B, Article I(1)A:
   A. Prior to restarting [CA-324], [Pacific Pipeline Company] shall apply for a State Waiver through the OSFM for the limited effectiveness of cathodic protection on [CA-324]. [Pacific Pipeline Company] must receive a State Waiver from the OSFM prior to restarting [CA-324].

2. Pacific Pipeline Company seeks relief from 49 C.F.R. 195.452(h)(4)(iii)(H) – Corrosion of or along a longitudinal seam weld.

(4) An explanation of the unique circumstances that the applicant believes make the applicability of that regulation or standard (or portion thereof) unnecessary or inappropriate for its facility;

General External Corrosion Under Insulation
CA-324 was shutdown in 2015 following the release on CA-324. A Consent Decree was entered by the District Court on October 14, 2020, that requires a State Waiver prior to restarting CA-324 and CA-325A/B. These specific requirements of the Consent Decree became applicable to PPC upon transfer of the assets. CA-324 is comprised of buried and insulated pipe. The pipeline has a coal-tar coating system and insulation wrap that provides corrosion deterrence.

PPC seeks approval to manage external corrosion of the pipeline through a supplemental combination of accelerated reassessments, usage of the appropriate assessment tools, integration of data from the appropriate alternating ILI technologies, enhanced anomaly response criteria targeted at corrosion under insulation, and advanced data analysis techniques to account for potential growth of corrosion under insulation including feature interaction criteria for anomaly assessment.

Selective Seam Weld Corrosion (SSWC)
The PHMSA Fact Sheet on Selective Seam Corrosion (known in industry as SSC or SSWC) describes SSWC as "a localized corrosion attack along the bond line of low-frequency electric resistance welded (LF-ERW) and electric flash welded (EFW) piping, that leads to the development of a wedge-shaped groove that is often filled with corrosion products."[1] The Fact Sheet goes on to say that "LF-ERW or EFW pipe manufacturing processes first came into use in the 1920s. Both types of pipe are manufactured by forming steel plates into round cylinders and then joining the longitudinal edges through a welding process. Due to technology and quality control issues with some of the pipe manufactured prior to 1970, the weld bondline may

[1] PHMSA Fact Sheet on Selective Seam Corrosion, December 1, 2011; <https://primis.phmsa.dot.gov/comm/FactSheets/FSSelectiveSeamCorrosion.htm>

be susceptible to corrosion processes. This is particularly true if the pipeline has the following conditions present:

- Exposure to corrosive conditions due to poor or absent coating;
- Ineffective cathodic protection; or
- The presence of non-metallic inclusions in the weld bondline region (e.g., contaminants present during the manufacturing process).

SSWC is generally not considered to be a concern with pipe manufactured after 1970 due to the use of cleaner steels having greatly reduced sulfur contents and the replacement of low frequency welding equipment with high frequency equipment in the manufacturing process." As provided in ***Attachment B***, Line CA-324 contains exclusively high frequency ERW (HF-ERW) longitudinal seamed pipe manufactured in 1985 and 1986. When ILI tools call corrosion along the seam, it may simply be corrosion incidental to the seam rather than preferential. Indeed, SSWC has not been observed in the previous direct examinations that make up the extensive dig history on this system. Therefore, the threat of SSWC is not considered applicable to Line CA-324. As such, selection of future inspection technologies will prioritize the identification and characterization of external blunt metal loss as the primary threat to this buried, insulated line, namely ultrasonic wall measurement (UTWM) and axial magnetic flux leakage (MFL-A) technologies.

Note that PPC only accepts calls from circumferential magnetic flux leakage (MFL-C), spiral magnetic flux leakage (SMFL), ultrasonic crack detection (UTCD) and/or electro magnetic acoustic transducer (EMAT) ILI systems when applying criteria for corrosion interaction with the longitudinal seam weld, as these technologies are designed for and, therefore are best suited for detection of the longitudinal seam weld and axially oriented corrosion. MFL-A and/or UTWM are not designed for detection of the longitudinal seam weld or axially oriented corrosion, so calls from those ILI systems are not reviewed for longitudinal seam weld interaction.

The CA-324 Las Flores Canyon to Gaviota testable segment was inspected using a MFL-C tool in February 2022, to better characterize the threat of external metal loss under insulation. Since SSWC has not been observed in the previous direct examinations that make up the extensive dig history on this system, PPC is therefore requesting OSFM to approve a State Waiver which allows for the use of prescript outlined engineering analysis and protocols to differentiate between corrosion anomalies that do not present a specific risk to the seam weld and associated heat affected zones in lieu of the current requirement under 49 C.F.R. § 195.452(h)(4)(iii)(H). Remediation and repair activities would then be scheduled according to the findings of the proposed evaluation. The following protocols would be applied to the 2022 MFL-C assessment of CA-324, along with all subsequent assessment results (as applicable, per the discussion above regarding tool technology), until the termination of the waiver.

(5) A description of any measures or activities the applicant proposes to undertake as an alternative to compliance with the relevant regulation, including an explanation of how such measures will mitigate any safety or environmental risks;

The Application includes memorializing certain integrity management procedures included in the Consent Decree in addition to further measures to maintain the integrity of the pipeline, including measures specific to SSWC. Many of these measures were negotiated and aligned upon as part of the Consent Decree.

The following measures are proposed, and have been categorized under inspection frequency, inspection validation, remediation criteria, selective seam weld corrosion, and general programmatic considerations.

Inspection Frequency

Rather than relying solely on fitness for service analysis to determine the deadline for next inspection and associated interval, PPC proposes to manage the potential for external corrosion rates on the pipeline by the following prescriptive guidelines for inspection frequency:

- PPC will inspect for potential external metal loss prior to restarting CA-324.
- PPC will inspect using UTWM ILI technology within 7 days of achieving initial steady-state operation in accordance with an ILI survey schedule approved by OSFM.
- PPC will inspect CA-324 for potential external metal loss annually, not-to-exceed a 15-month interval between inspections. The annual inspections will alternate ILI survey technologies employed (i.e., axial magnetic flux leakage (MFL-A) or ultrasonic wall measurement (UTWM)). Alternatively, PPC may run a UTWM tool each year.
- Where any ILI survey fails to record data for 5% or more of the external and/or internal surface area of the inspected segment, the ILI tool will be rerun to cover the area lacking coverage.

Inspection validation

Inspection validation is crucial to ensuring tool tolerances and developing corrosion growth analyses that accurately reflect the integrity condition of the pipeline. Following an ILI survey to evaluate potential external metal loss, PPC proposes the following:

- ILI surveys will be validated consistent with API Standard 1163 In-line Inspection Systems Qualification, 3rd Edition, September 2021 Level 2 validation methodology, at a minimum. This process will leverage field direct examination measurements of previously repaired external metal loss anomalies that have been preserved (e.g. corrosion mechanism has been arrested by recoating or composite repair installation) to support validation as well as any additional external metal loss validation inspections necessary to support validation. The depths relied upon for validation of the ILI survey will include external metal loss depths between 10% and 40%.
- ILI tool vendors will be required to apply interaction/clustering criteria of 6t by 6t for applicable ILI tools.
- ILI tool vendors will report all external metal loss anomalies of 10% or greater, based on raw data, prior to adding in any correction for tool tolerance.
- When employing magnetic flux leakage (MFL) ILI tools, ILI tool vendors will be required to manually grade any external metal loss anomalies initially identified by the ILI tool as greater than or equal to 20% of wall loss and the vendor's ILI report must note any

differences between what the computer algorithm reported and the vendor's manual grade.

- All field direct examination measurements gathered by PPC will be provided to the ILI tool vendor following completion of direct examinations for an ILI survey.

Remediation criteria

Following an ILI survey, the following guidelines are proposed to address survey results:

- PPC will remediate all external metal loss anomalies that have an ILI reported depth without including tool tolerance of 40% or greater wall loss, within one year of discovery. If PPC is unable to remediate such anomalies within one year of discovery, PPC will notify OSFM and temporarily reduce the operating pressure and/or take further remedial action in accordance with 49 C.F.R. § 195.452 until the anomaly is remediated (or until otherwise authorized by OSFM).
- All external metal loss anomalies will be further evaluated via suitable remaining strength calculation methods, which per 49 C.F.R. § 195.452(h)(4)(i)(B) include, but are not limited to, ASME/ANSI B31G (incorporated by reference, see § 195.3) and PRCI PR-3-805 (R-STRENG) (incorporated by reference, see 49 C.F.R. § 195.3). Anomalies will then be scheduled for remediation per 49 C.F.R. § 195.452(h)(4)(i), (ii), and (iii)(A-G) and (I), and consistent with PPC's Integrity Management Program. All remaining anomalies that do not meet depth or remaining strength conditions for remediation will be subject to a corrosion growth analysis that accounts for ILI tool tolerance, and all anomalies will be reassessed or repaired by their resultant half-life.
- Any time a shrink sleeve is exposed during an anomaly investigation, the shrink sleeve will be removed, investigated circumferentially and longitudinally along the pipe for external corrosion and coating deterioration, and recoated with two-part epoxy.

Annual inspections will allow for prompt identification of locations with accelerated corrosion growth rates, and the proposed remediation criteria will effectively arrest corrosion growth of remaining features well before approaching potential failure states. In fact, at a metal loss depth of 40% of nominal wall thickness, there is no credible length at which an anomaly will fail at a burst pressure (calculated using ASME/ANSI Modified B31G) less than or equal to MOP, for all pipe specifications across the entire Las Flores Pipeline system operated by PPC.

Selective Seam Weld Corrosion

PPC maintains that the pipe comprising the Las Flores Pipeline system is not susceptible to Selective Seam Weld Corrosion (SSWC), as supported by field data collected during excavation and inspection activities which finds the characterization of corrosion *incidental* to the long seam rather than *preferential* to the long seam. However, PPC proposes the following measures in relation to SSWC:

- All anomalies 'of or along the longitudinal seam weld' and associated heat affected zone (defined as being 1" wide on either side of the weld) will be subject to API RP 1176 for Assessment and Management of Cracking in Pipelines and associated response methodology, and in accordance with API 579-1/ASME FFS-1, December 2021 Fitness-For-Service. All such anomalies will be further evaluated as blunt metal loss corrosion via suitable remaining strength calculation methods. Anomalies will then be scheduled for remediation per 49 C.F.R. § 195.452(h)(4)(i), (ii), and (iii)(A-G) and (I), and consistent with PPC's Integrity Management Program.

- All corrosion anomalies 'of or along the longitudinal seam weld' and associated heat affected zone will first be evaluated as crack-like features using API RP 579-1/ASME FFS-1, December 2021 – Level II or Level III fitness for service calculations to determine the Failure Pressure Ratio (FPR) for each anomaly. Material properties will be selected consistent with 49 C.F.R. § 192.712 - Analysis of predicted failure pressure. Anomaly depth and FPR values will then be evaluated against API RP 1176 response criteria (Section 11.7) for 'likely cracks' (most severe classification). All remaining anomalies that do not meet depth or remaining strength conditions for remediation will be subject to fatigue analysis performed using an applicable fatigue growth law (e.g. Paris Law) or other technically appropriate engineering methodology. Final anomaly size will be determined using a fracture mechanics model appropriate to the failure mode (ductile, brittle, or both) and boundary condition used (pressure test, ILI, or other). Accounting for tool tolerance, all anomalies will be reassessed or repaired by their resultant half-life.
- All corrosion anomalies 'of or along the longitudinal seam weld' and associated heat affected zone will then be evaluated as blunt metal loss via suitable remaining strength calculation methods, which per 49 C.F.R. § 195.452(h)(4)(i)(B) include, but are not limited to, ASME/ANSI B31G (incorporated by reference, see § 195.3) and PRCI PR-3-805 (R-STRENG) (incorporated by reference, see § 195.3). Anomalies will then be scheduled for remediation per 49 C.F.R. § 195.452(h)(4)(i), (ii), and (iii)(A-G) and (I), and consistent with PPC's Integrity Management Program. In addition to the standard requirements – and consistent with the set of waiver conditions proposed for External Corrosion – all metal loss anomalies with an ILI reported depth of 40% or greater wall loss will be scheduled for remediation within one year of Discovery. As previously stated, if PPC is unable to remediate such anomalies within one year of Discovery, PPC will notify OSFM and temporarily reduce the operating pressure and/or take further remedial action in accordance with 49 C.F.R. § 195.452 until the anomaly is remediated (or until otherwise authorized by OSFM). All remaining anomalies that do not meet depth or remaining strength conditions for remediation will be subject to a corrosion growth analysis, where once again – and accounting for tool tolerance – all anomalies will be reassessed or repaired by their resultant half-life. Note that this does not supersede the annual UTWM/MFL requirements set forth per the External Corrosion waiver conditions.
- After the analyses are complete, anomalies not scheduled for remediation will be tracked, and corrosion growth will be assessed with each future ILI survey. P&M measures will be assessed through regular IMP activities and implemented on the pipeline per 49 C.F.R. § 195.452 (f)(6) as needed.

General Programmatic Considerations

PPC will conduct its preventative and mitigative measures process to integrate and analyze all available data for CA-324, including, but not limited to:

- Assessment data from in-line inspection (ILI) tool runs;
- Anomaly investigation, inspection, and repair data;

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

The potential for external corrosion and selective seam weld corrosion will be re-examined as new and additional data becomes available through integrity assessment activities and through normal operation of the pipeline. PPC will amend its Integrity Management Program, to include the State Waiver conditions specific to CA-324.

(6) A description of any positive or negative impacts on affected stakeholders and a statement indicating how operating the pipeline pursuant to a special permit would be in the public interest;

Positive impacts on affected stakeholders and operating the covered pipeline segments in accordance with the State Waiver will be in the public interest for the following reasons:

- Limit impacts to the environment and potential locations for cultural resources by reducing unnecessary anomaly digs in areas of low or no risk.
- Maintain the priority of pipeline maintenance activities to sections of the pipeline in greatest need of monitoring for pipeline safety.
- Reduce unnecessary excavation around other critical infrastructure.
- Reduce the permitting workload of public agencies along the pipeline right-of-way.
- Reduce the general risks and impacts, to both the workforce and the public, associated with excavations in and along public highways and other rights-of-way.
- Limit disruptions to the public and to property owners.

(7) A certification that operation of the applicant's pipeline under the requested waiver would not be inconsistent with pipeline safety;

Approval of this State Waiver request focused on characterization and remediation of external corrosion features, will help prioritize conditions that are the most important for the continued safe operation of this pipeline system and will enhance the effectiveness of the Las Flores Pipeline integrity management program. This request also supports prioritization of resources and aligns pipeline integrity evaluation criteria with explicit protocols. All of the operational protocols that PPC is proposing exceed other regulatory requirements and are protective of pipeline safety.

(8) If the application is for a renewal of a previously granted waiver or special permit, a copy of the original grant of the waiver or permit; and

N/A; this is an initial application.

(9) Any other information PHMSA may need to process the application including environmental analysis where necessary.

Note that PPC is not seeking relief from 49 C.F.R. § 195.563 and the requirements to provide cathodic protection for buried pipelines. The cathodic protection system remains active and continues to be maintained on the Las Flores Pipeline system. Rather, PPC proposes the aforementioned inspection and remediation actions as a means of addressing the limitations of cathodic protection PHMSA observed for buried, insulated pipe.

Cathodic protection will continue to be implemented on the pipeline system at appropriate levels in adherence to 49 C.F.R. 195 and tested at appropriate intervals. Cathodic protection will continue to function with high effectiveness at pipeline repair locations where the thermal insulation has been removed.

PPC maintains that the proposed conditions and facts-at-matter for the pipeline describe a conservative and measured approach to the identification and remediation of external corrosion metal loss features on the Las Flores Pipeline system, adequately manage risk factors associated with cathodic protection, and enable safe, long-term operation of the pipeline.

We thank you for your consideration of this State Waiver request. If you have any questions, or require anything further to conduct your review of this request, please do not hesitate to contact me. I also ask that PPC be given the opportunity to amend this application as needed to provide additional information or address deficiencies identified by the OSFM before formal action is taken to reject or deny the application.

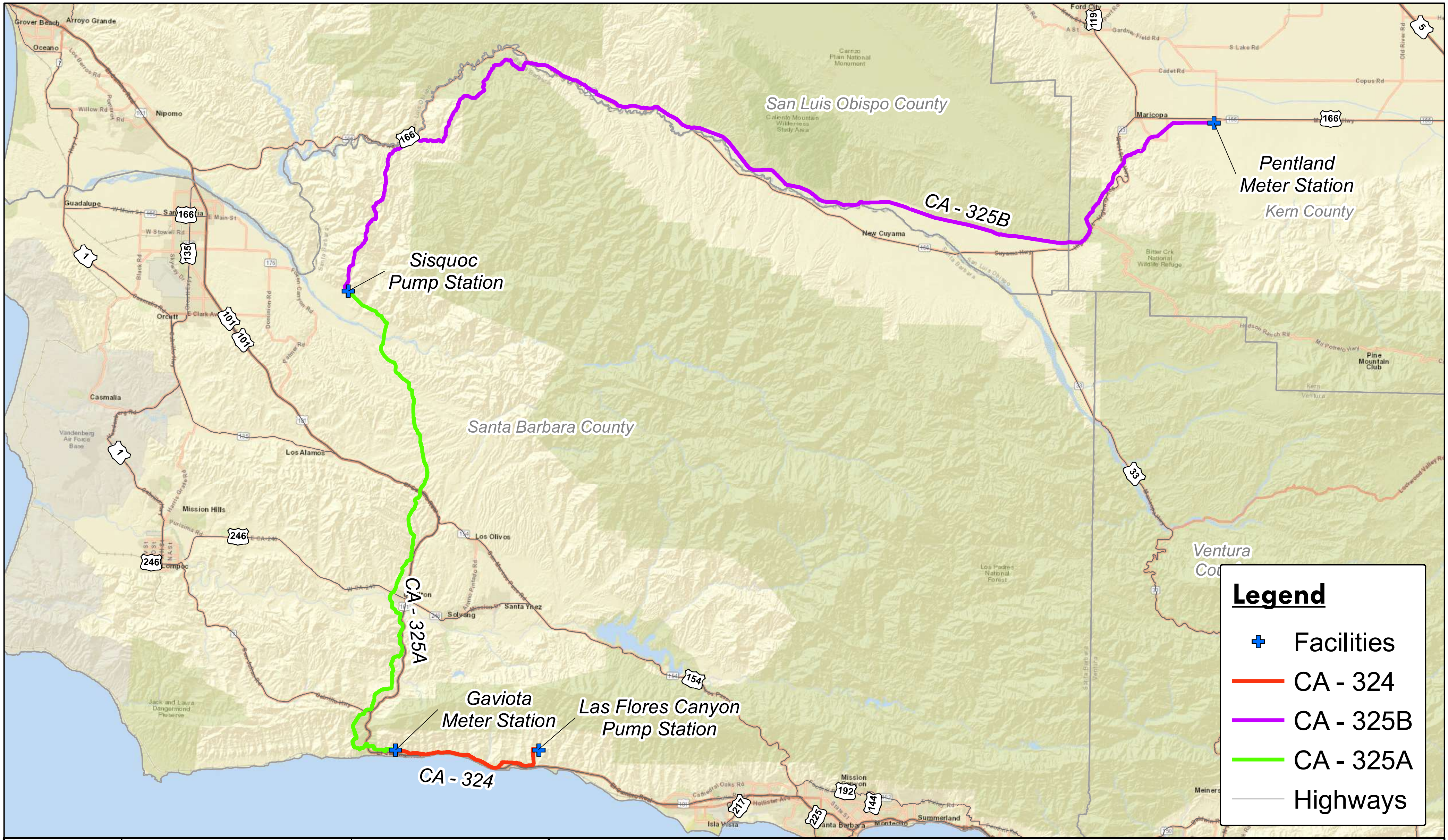
Sincerely,

Diana Skates
Pipeline Safety Advisor
Pacific Pipeline Company

Attachments: A: Las Flores Pipeline System Map & Trunk Line Chart
B: Las Flores Pipeline Background Data

cc: Alin Podoreanu, Supervising Pipeline Safety Engineer, OSFM
Andy Chau, Supervising Pipeline Safety Engineer, OSFM
Brandon Ferry, Supervising Pipeline Safety Engineer, OSFM
Doug Allen, Supervising Pipeline Safety Engineer, OSFM
Durga Shrestha, Pipeline Safety Engineer, OSFM
Huy Tran, Supervising Pipeline Safety Engineer, OSFM
Josh Cleaver, Staff Counsel, OSFM
Matthew Young, Senior Pipeline Integrity Advisor, ExxonMobil Pipeline Company LLC (EMPCo)
Rebekah Bennett, General Counsel, PPC & EMPCo

ATTACHMENT A



PACIFIC PIPELINE COMPANY

SCS ENGINEERS

North

Scale

1 in = 5 miles

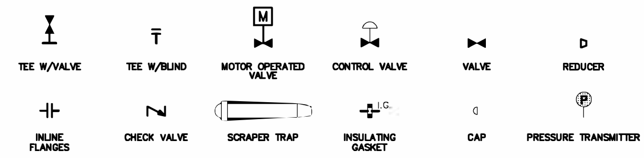
0 2 4 6 8 10 Miles

Prepared by SCS Engineers
January 2022
Source: GCS, NAD 83

Las Flores Pipeline System

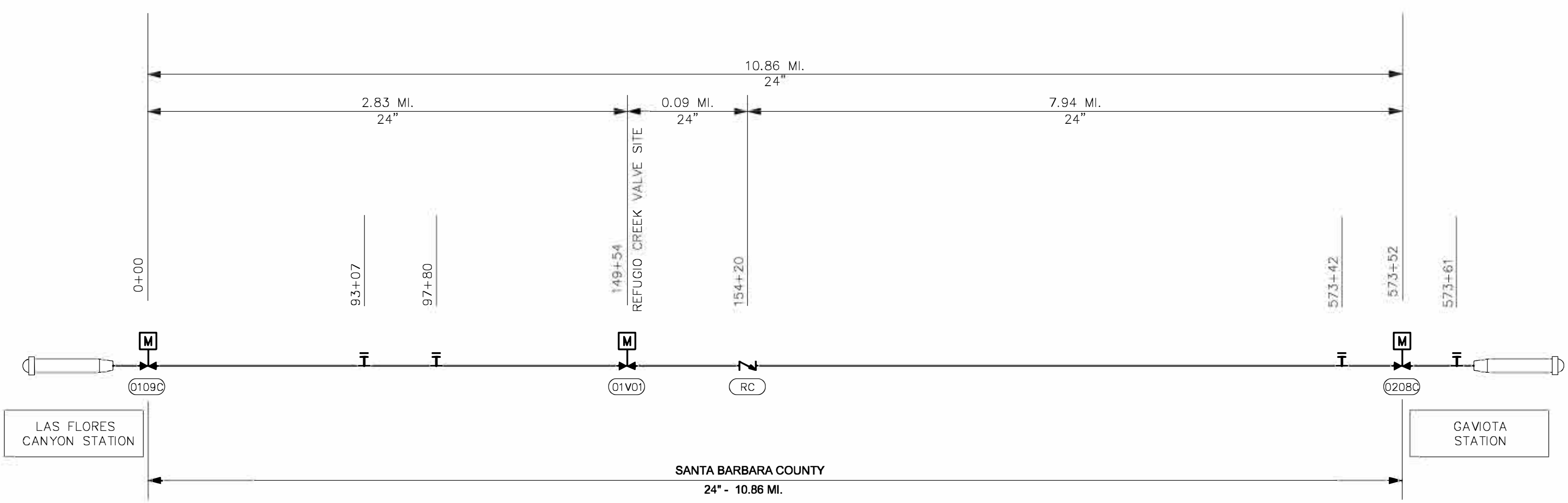
ATTACHMENT A

EQUATIONS	TESTABLE SEGMENT
EQ. X+X BK X+X AH	LAS FLORES CANYON TO GAVIOTA 0+00 TO 573+52



TRUNK LINE CHART SYMBOLOGY LEGEND AND REFERENCE

NOTE: OPERATING SCHEMATIC ONLY FOR
COMPLETE GEOGRAPHICAL AND INVENTORY
INFORMATION SEE ALIGNMENT SHEETS.



TOTAL PIPE	DISPLACEMENT
PID 13680 24" = 10.86 MI.	PID 13680 24" = 30,263 BBLS (ACTIVE)

LAS FLORES PIPELINE

LAS FLORES PIPELINE (LAS FLORES CANYON TO GAVIOTA)
24" CRUDE

1992
TOTAL ACTIVE DISPLACEMENT = 30,263 BBLS

REFERENCE DRAWINGS

DWG. NO.	DESCRIPTION
*	*

REV.	DATE	DESCRIPTION	BY	CHKD	APPD.
A	07/22	PRELIMINARY - IFR	NGP	QS	APPD.

ExxonMobil Pipeline
HOUSTON, TEXAS
TRUNK LINE CHART
CA-324

PID 13680	PID X	PID X	PID X

DCC# X
T-4# X

Pipeline System Background Data

Attachment B
of
State Waiver Application

PACIFIC PIPELINE COMPANY

LAS FLORES PIPELINE SYSTEM
CA-324, CA-325A/B

June 2023

Issued by:

PACIFIC PIPELINE COMPANY

PURPOSE

Supplemental information to Pacific Pipeline Company's State Waiver Application is included herein to summarize relevant details related to the pipelines and associated operation that may be considered in support of State Waiver conditions. The following is summarized:

- Pipeline Description
- Pipeline Specifications
- Hydrostatic Test Information
- Maximum Operating Pressure
- Normal Operating Pressures
- In-line Inspection History
- Coating and Cathodic Protection System Information

PIPELINE DESCRIPTION

The CA-324 24-inch pipeline (formerly referred to as Line 901) is approx. 10.86 miles in length and generally parallels U.S. Highway 101 along the south coast between the Las Flores Canyon consolidated oil and gas processing facility and the Gaviota Station. The pipeline is located north of U.S. 101 and generally follows powerline and/or natural gas pipeline rights-of-way across coastal terraces and incised canyons.

The CA-325A 30-inch pipeline (formerly referred to as Line 903 – Gaviota to Sisquoc) is approx. 38.72 miles in length. The pipeline extends west from the Gaviota Station to an MOV located east of Gaviota Creek and U.S. Highway 101. It then enters Gaviota State Park approx. 0.5 miles east of U.S. Highway 101 and extends westerly across the gently sloping coastal terrace and Cañada del Barro before dropping into the Cañada de la Gaviota drainage area. It then crosses U.S. Highway 101 and Gaviota Creek (Cañada de la Gaviota) immediately south of the U.S. Highway 101 "Caltrans" rest stop area. The pipeline then extends west and north from the Gaviota Creek MOV. The pipeline continues west up a broad spur ridge to the ridge crest and the westerly boundary of Gaviota State Park. The pipeline traverses narrow ridge crests, crosses out of the Park and onto Hollister Ranch for approx. 0.5 miles, and then crosses back into the Park before descending toward the west fork of Gaviota Creek (Betty Creek). The right-of-way passes west of the Vista del Mar School and Las Cruces Adobe and then crosses beneath Highway 1 west of its intersection with U.S. Highway 101. The pipeline continues northward along the west side of U.S. Highway 101 through the Santa Ynez Mountains. It crosses long expanses of grasslands across the Las Cruces Ranch and steep walled canyons that form part of the Nojoqui Creek watershed. North of Moonshine Creek, the route crosses ridges with rock outcroppings. The pipeline crosses beneath the Santa Ynez River west and south of Buellton and continues north across the Purisima and Solomon Hills. It crosses the northern edge of the San Rafael Mountains and the eastern edge of the Santa Maria Valley. The pipeline crosses beneath the Sisquoc River and continues north across the River Valley. It traverses moderately to severely sloping foothills at Kelly Canyon and extends west to the Sisquoc Station at the southern end of Santa Maria Canyon.

The CA-325B 30-inch pipeline (formerly referred to as Line 903 – Sisquoc to Pentland) is approx. 74.84 miles in length. The pipeline follows Santa Maria Canyon after leaving the Sisquoc Station. It then extends northeast towards Tepusquet Road. The route crosses relatively gentle terrain until it reaches the crest of the Sierra Madre Mountains where it traverses steep slopes approaching Suey Canyon and Buckhorn Canyon. The pipeline follows the northern edge of the Sierra Madre Mountains south of State Highway 166 through the Los Padres National Forest. The route crosses rugged terrain across the crests of the Sierra Madre Mountains, descends the mountains, crosses the Sierra Madre Ridge Road, and enters the Cuyama River Valley near Gypsum Canyon. At the Cuyama River crossing, the pipeline exits Santa Barbara County and enters San Luis Obispo County. The pipeline continues for approx. 44.5 miles through ranch land, terminating at the Pentland Station in Kern County.

The routing of the Las Flores Pipelines has been considered for its impact on High Consequence Areas (HCA) per established PPC Integrity Management Plan guidelines and applicable regulations. Table B-1 provides a high-level summary of High Consequence Areas (HCAs) along the Las Flores Pipeline System.

TABLE B-1: HIGH CONSEQUENCE AREA SUMMARY

Pipeline Designation	Location	Total Mileage	High Consequence Area (HCA) Type
CA-324	Las Flores Canyon to Gaviota	10.86	Impact to ecologically sensitive regions (coastline)
CA-325A	Gaviota to Sisquoc	38.72	Impact to the city of Buellton (population center, drinking water), and ecologically sensitive regions
CA-325B	Sisquoc to Pentland	74.84	Impact to ecologically sensitive regions

The Las Flores Pipeline traverses multiple Counties as well as State and Federal jurisdictions. Approximate mileage is included in Table B-2, below.

TABLE B-2: JURISDICTIONAL MILEAGE

	Jurisdiction	CA-324 (miles)	CA-325A (miles)	CA-325B (miles)	Total (miles)
County	Santa Barbara County	10.9	38.7	23.8	73.4
	San Luis Obispo County	0	0	37.2	37.2
	Kern County	0	0	13.8	13.8
	Total	10.9	38.7	74.8	124.4
Sub-Jurisdiction *(Note 1)*	California State Parks and Recreation (Gaviota State Park)	0	4.1	0	4.1
	U.S. Forest Service	0	0	6.3	6.3
	U.S. Fish and Wildlife (Bitter Creek Wildlife Refuge)	0	0	4.5	4.5
	California Dept. of Fish and Wildlife (Carrizo Plain Ecological Reserve)	0	0	4.5	4.5
	Bureau of Land Management	0	0	1.0	1.0
	City of Buellton	0	1.1	0	1.1
	Total	0	5.2	16.3	21.5

Note 1: Mileage included in County jurisdiction

PIPELINE SPECIFICATIONS

CA-324 is manufactured of low carbon steel. It contains predominantly 0.344-inch nominal wall thickness, high frequency electric resistance welded (HF-ERW) API 5L X65 pipe manufactured in 1985 and 1986 by Nippon Steel Corp., Hikari Works mill, in Japan using plate steel with UOE pipe forming process. A summary of CA-324 line pipe specifications is included in Table B-3.

CA-325A/B is manufactured of low carbon steel. It contains various grades and wall thicknesses of double submerged arc welded (DSAW) API 5L pipe manufactured between 1984 and 1986, from a variety of mills in Belgium, Brazil, France, Germany, and Israel, summarized in Table B-4. Additionally, it includes small portions of replaced sections with newer pipe, including HF-ERW. A summary of CA-325A/B line pipe specifications is included in Table B-3.

TABLE B-3: LINE PIPE SPECIFICATIONS

Pipeline Designation	Outside Diameter (in)	Nominal Wall Thickness (in)	Grade	Seam Type	Year Installed	Length (mi)
CA-324 Las Flores Canyon to Gaviota	24	0.344	X65	HF-ERW	1990	10.69
	24	0.375	X65	HF-ERW	1990	0.02
	24	0.5	X60	HF-ERW	1990	0.16
CA-325A Gaviota to Sisquoc	30	0.281	X70	DSAW	1986	21.85
	30	0.344	X65	DSAW	1986	12.47
	30	0.375	X65	DSAW	1986	2.27
	30	0.375	X65	DSAW	2014	0.12
	30	0.406	X65	DSAW	1986	0.38
	30	0.406	X65	HF-ERW	2000	0.03
	30	0.438	X70	DSAW	1986	0.17
	30	0.5	X60	DSAW	1986	0.75
	30	0.5	X70	DSAW	1986	0.28
	30	0.562	X65	DSAW	1986	0.06
	30	0.75	X65	DSAW	1986	0.35
CA-325B Sisquoc to Pentland	30	0.281	X70	DSAW	1986	19.29
	30	0.344	X65	DSAW	1986	17.03
	30	0.344	X65	DSAW	2007	0.24
	30	0.375	X65	DSAW	1986	12.88
	30	0.375	X70	DSAW	2017	0.16
	30	0.375	X70	DSAW	2018	0.02
	30	0.406	X65	DSAW	1986	0.12
	30	0.438	X70	DSAW	1986	24.41
	30	0.5	X60	DSAW	1986	0.13
	30	0.5	X70	DSAW	1986	0.28
	30	0.625	X65	DSAW	1986	0.01
	30	0.75	X70	DSAW	1986	0.27

TABLE B-4: CA-325A/B LINE PIPE MILL INFORMATION

Mill	Location	Plate or Coil	Pipe Forming Process
Bergroh	Germany	Plate	Three Beam Rollers
Confab	Brazil	Plate	UOE
Hoesch	Germany	Coil	Spiral
Metco	Israel	Coil	Spiral
Sacilor	France	Coil	Spiral
Tubemeuse	Belgium	Coil	Spiral
Tubes de Belville	France	Plate	C-press
Vallourec (GTS)	France	Plate	UOE
Mannesmann	Germany	Plate	UOE

HYDROSTATIC TEST INFORMATION

CA-324 was hydrostatically pressure-tested on November 25, 1990 to 1765 pounds per square inch gauge (psig), as calculated at the highest elevation. CA-325A was hydrostatically pressure-tested in nine separate segments between pressures of approx. 778 to 1757 psig, as calculated at the highest elevations of each segment, between October 14, 1986 and December 3, 1986. CA-325B was hydrostatically pressure-tested within eleven separate segments between pressures of 686 to 1753 psig, as measured at the highest elevations of each segment, between January 13, 1986 and November 8, 1986. Portions of pipe replaced after original construction hydrotest were tested at or above the originally established test pressure and established maximum operating pressure (MOP) prior to being placed into service. A summary of the percent of specified minimum yield strength (%SMYS) and the corresponding MOP, as established by the original construction hydrotest records, is included in Table B-5. A summary of original construction hydrotest records are included in Table B-6.

TABLE B-5: ORIGINAL CONSTRUCTION HYDROTEST – %SMYS AND MOP RANGES

Pipeline Designation	%SMYS		Corresponding MOP to Test Pressure (psig)	
	Min	Max	Min	Max
CA-324	54.5%	72.0%	1133	1410
CA-325A	25.8%	72.0%	622	1085
CA-325B	37.0%	72.0%	549	1472

TABLE B-6: HISTORIC HYDROTEST SUMMARY

Pipeline Designation	Test Segment Identifier	Date	Begin Station	End Station	Minimum Test Pressure at Max Elevation (psig)	MOP at Max Elevation (psig) ***(Note 1)***
CA-324	LF - Gav	11/25/1990	0	57352	1416	1133
CA-325A	11	10/14/1986	238652	259872	863	690
	12	11/14/1986	179721	235388	778	622
	13	11/14/1986	144307	179721	784	627
	14	11/21/1986	137049	144307	1083	866
	SYR	12/3/1986	135120	137049	1757	1406
	15-16	10/30/1986	111386	135120	1155	924
	17	10/29/1986	93221	111386	1120	896
	18	11/19/1986	66621	93221	906	725
	19	11/19/1986	55421	66621	1105	884
CA-325B	1	1/13/1986	639412	733359	1344	1075
	1A	9/7/1986	618385	639412	1025	820
	2	9/9/1986	608271	618385	906	725
	3	9/14/1986	505520	608271	686	549
	4	9/17/1986	415547	505520	1125	900
	5A	9/17/1986	385240	415547	1753	1403
	5B	11/8/1986	359963	385240	1219	975
	6	10/18/1986	338470	359963	992	793
	7	10/21/1986	316971	338470	1484	1187
	8-9	10/16/1986	268171	316971	1183	946
	10	10/14/1986	260278	268171	1449	1160

Note 1: This value is simply the resultant, corresponding, MOP based upon the hydrostatic test record. It does not reflect the MOP value the Operator, Pacific Pipeline Company, assigns the pipelines and is only included for context.

MAXIMUM OPERATING PRESSURE

Due to the dramatic elevation profile and resultant hydraulic pressure profile of the Las Flores Pipeline System, Maximum Operating Pressure (MOP) has been documented using a variable MOP methodology, in which MOP is a function of pipe stationing (distance). The documented MOP is based upon hydrostatic test records, documented pipeline elevation profile, relevant design codes, and Pacific Pipeline Company's hydraulic analysis that contemplates all possible steady-state and transient operating scenarios, including surge and incorrect operations.

All potential modes of operation, including normal and abnormal, were evaluated in an engineering and hydraulic analysis conducted in 2023 to determine maximum pressures that may be experienced on the pipeline during various modes of operation. The hydraulic analysis considered multiple worse-case steady-state operating conditions, such as maximum flow and maximum hydraulic pressure gradient scenarios as well as over sixty initiating transient events, including inadvertent valve closures, start-up and shutdown, and pump trips.

The maximum pressures that resulted from the analysis were compared to historic hydrostatic test records, official pipeline elevation data from inspections, and considered regulation and design code. The basis to define the pipeline's MOP for each segment is summarized in Table B-7. The absolute maximum steady-state and transient pressure profile for all possible normal and abnormal operating modes is represented in Figures B-1, B-2, and B-3. A summary of the percent of specified minimum yield strength (%SMYS) and the corresponding current, documented and official, MOP for the pipeline is included in Table B-8.

TABLE B-7: SUMMARY OF MOP BASIS

Pipeline Designation	Explanation of MOP Basis
CA-324	100 psi above max steady-state & transient pressure profile
CA-325A	100 psi above max steady-state & transient pressure profile
CA-325B	50 psi above max steady-state & transient pressure profile for Mile Post 49.57 to Mile Post 117.41 80% of original construction hydrostatic test pressure for Mile Post 117.41 to Mile Post 124.42

TABLE B-8: DOCUMENTED, OFFICIAL MOP – %SMYS AND MOP RANGES

Pipeline Designation	%SMYS		Documented MOP (psig)	
	Min	Max	Min	Max
CA-324	28.5%	55.4%	684	1003
CA-325A	21.7%	67.9%	444	1000
CA-325B	21.9%	72.0%	317	1292

FIGURE B-1: CA-324 MAXIMUM OPERATING PRESSURE

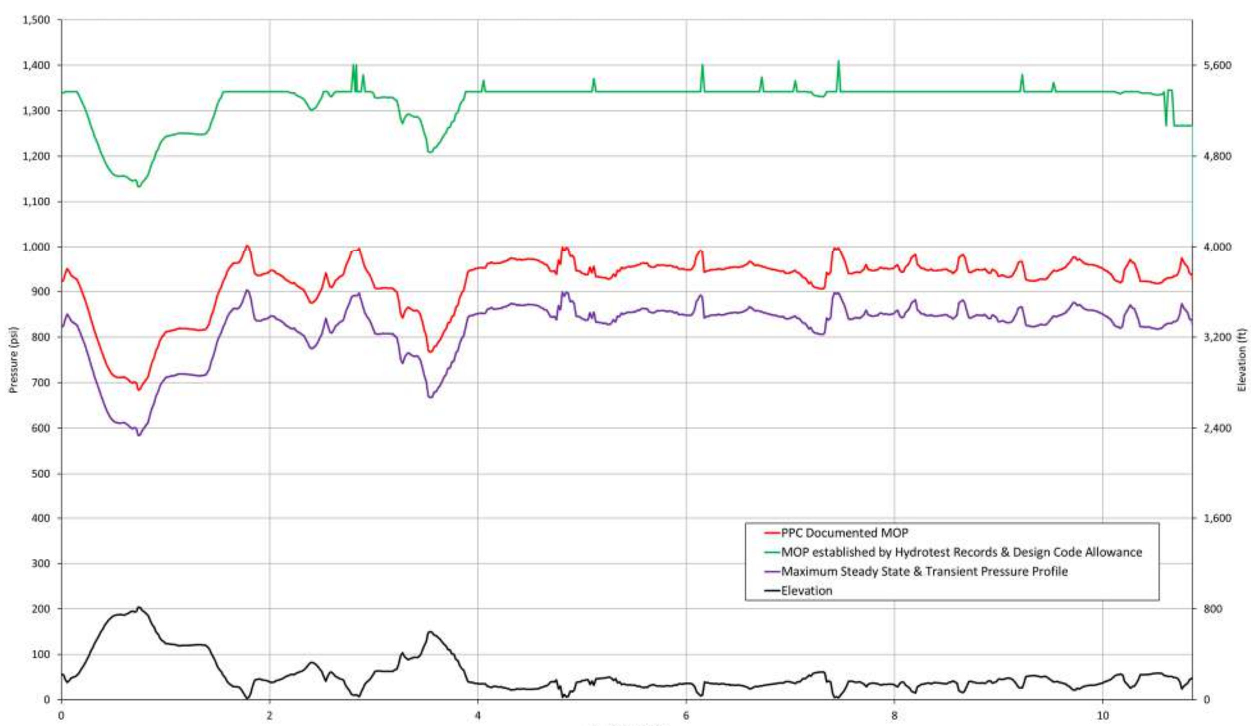


FIGURE B-2: CA-325A MAXIMUM OPERATING PRESSURE

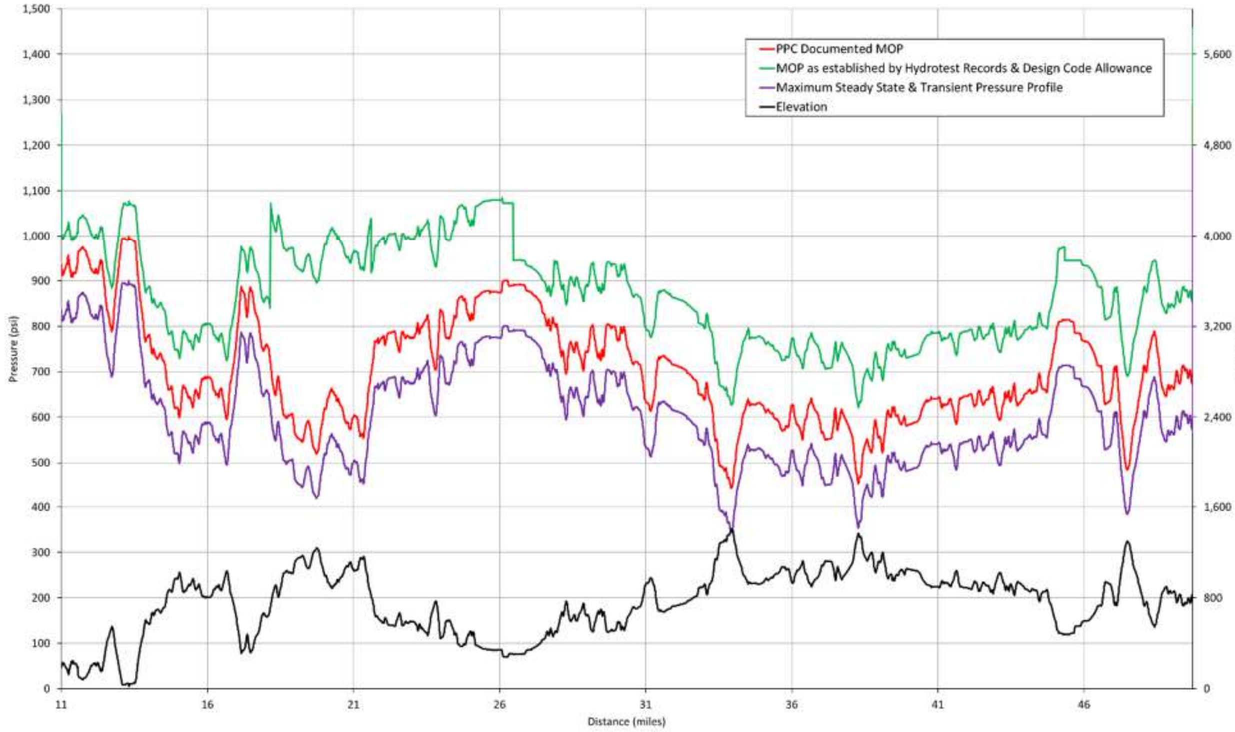
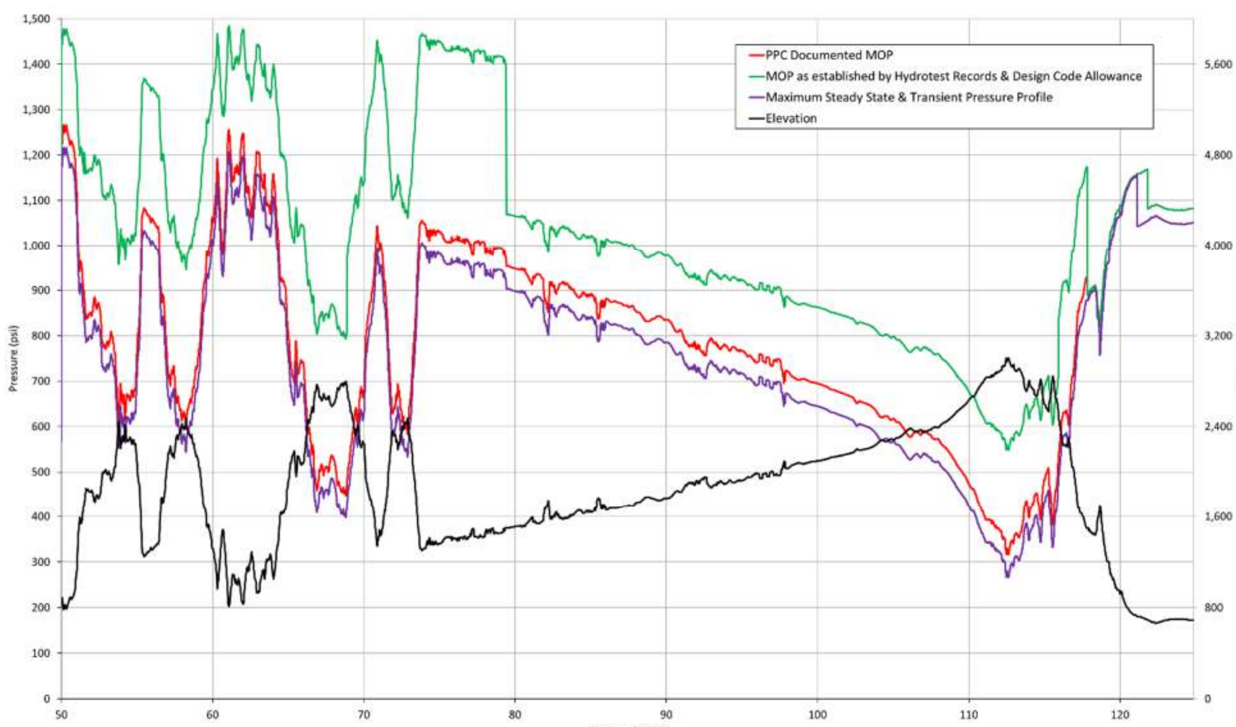


FIGURE B-3: CA-325B MAXIMUM OPERATING PRESSURE



NORMAL OPERATING PRESSURES

In order to establish the Normal Operating Pressure (NOP) range for the Las Flores Pipeline System, PPC evaluated over seventeen different operating conditions to document relevant hydraulic information. An array of the following conditions and variables were considered to capture the range of potential operating conditions.

- Flow rates
- Suction pressure, discharge pressure, and backpressure control parameters
- Allowable pump and pressure/flow control device operating scenarios
- Fluid temperatures
- Soil temperatures
- Fluid characteristics (e.g. density, viscosity)

Historical operating data was used to validate the hydraulic model and ensure analysis accuracy, and a few historical operating data points are captured in Figures B-4, B-5, and B-6, for reference. The resultant minimum and maximum typical pressure ranges based upon the range of steady state scenarios are documented in Figures B-4, B-5, and B-6.

FIGURE B-4: CA-324 NORMAL OPERATING PRESSURE

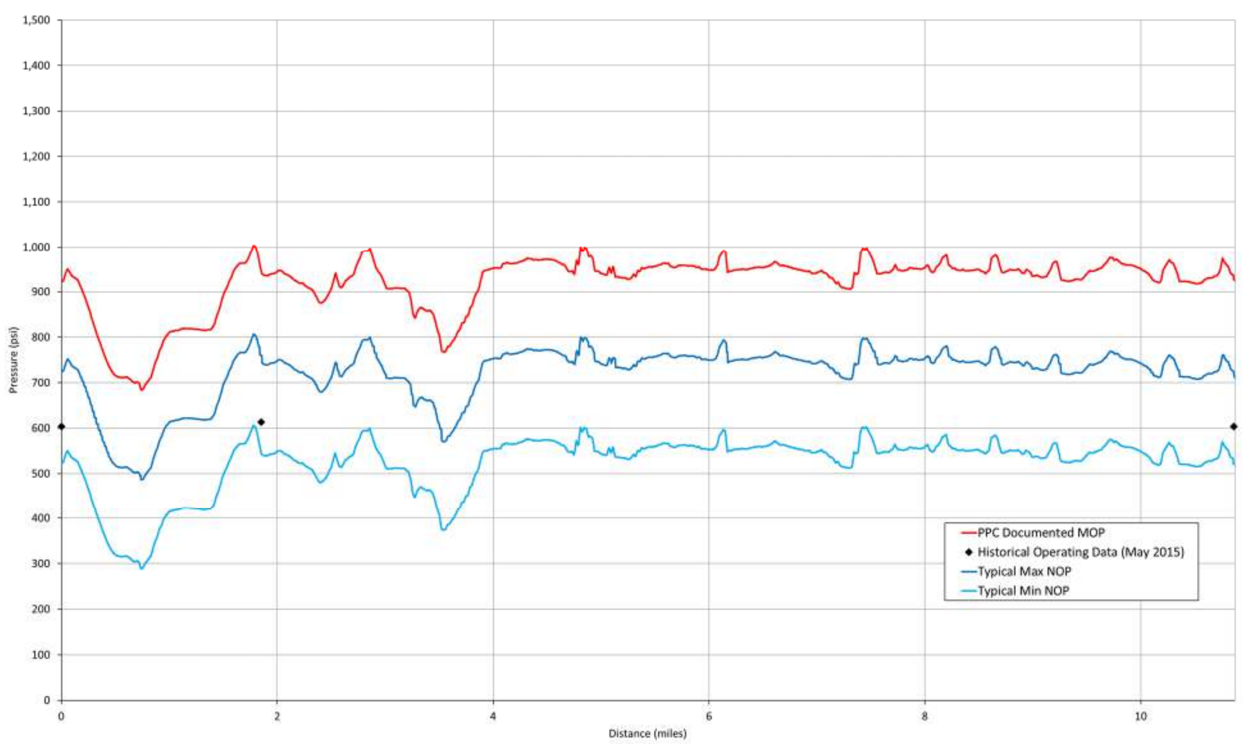


FIGURE B-5: CA-325A NORMAL OPERATING PRESSURE

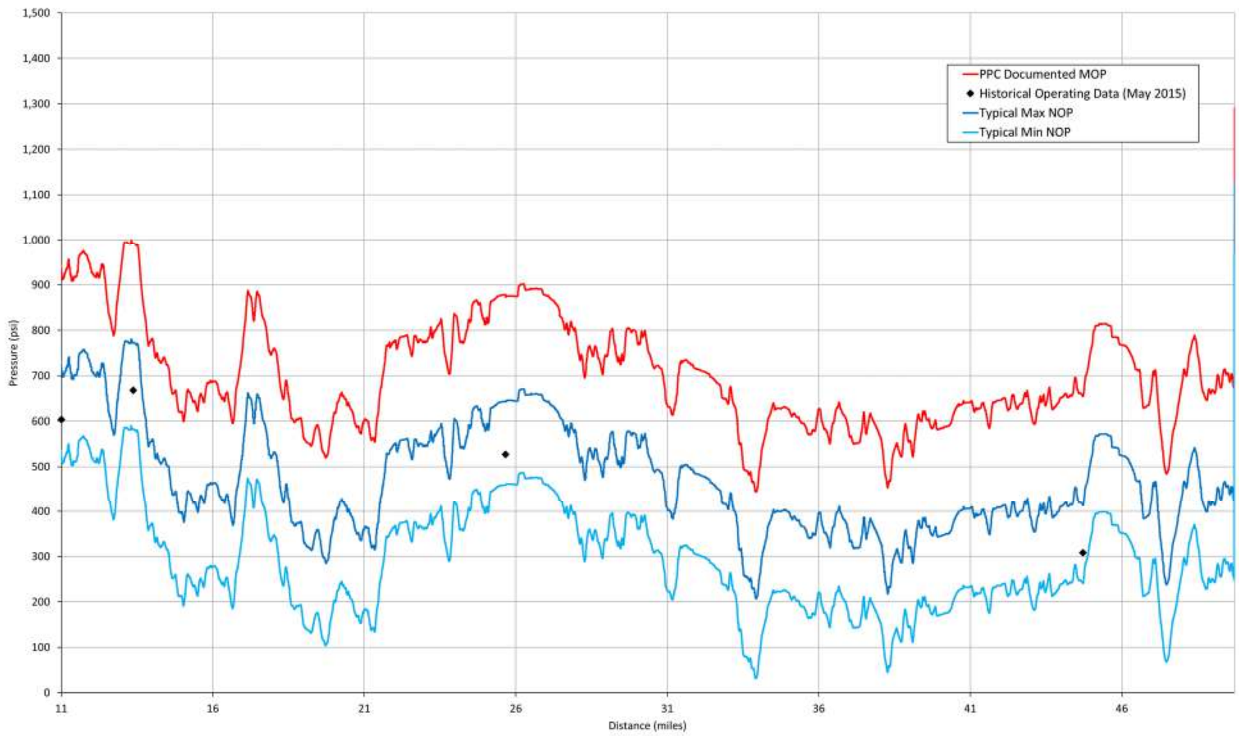
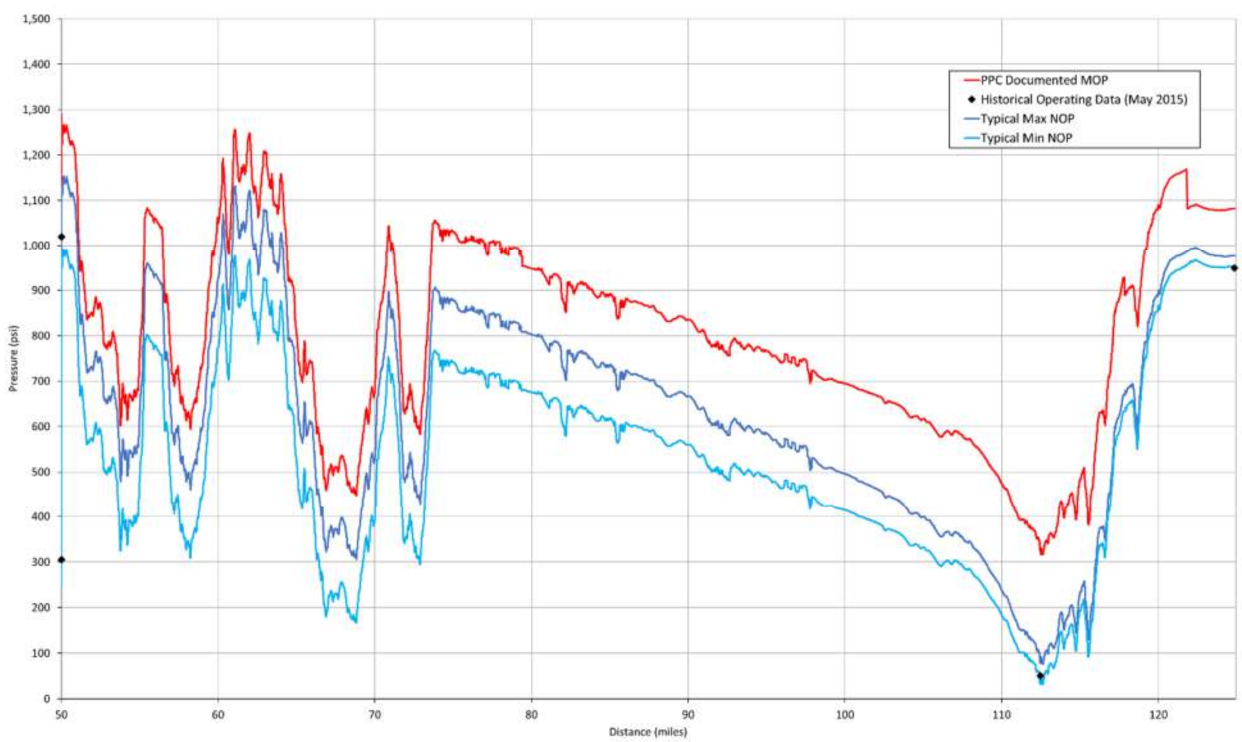


FIGURE B-6: CA-325B NORMAL OPERATING PRESSURE



In-Line Inspection History

The following Table B-9 provides a summary of CA-324, CA-325A, and CA-325B In-Line Inspection (ILI) activities, as of July 2023. Note that CA-324 Las Flores Canyon to Gaviota has been inspected since the 2015 release, in February and December of 2022 (circumferential magnetic flux leakage (MFL-C) and ultrasonic wall measurement (UTWM) surveys, respectively).

Table B-9: In Line Inspection Summary

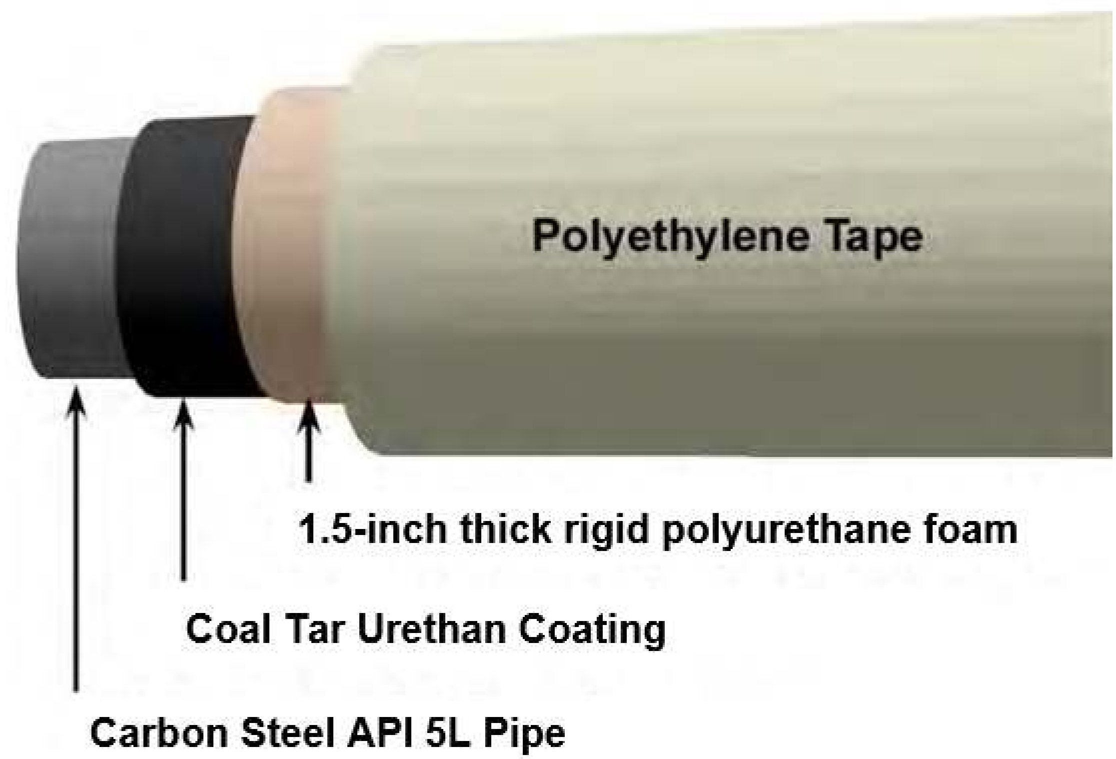
Pipeline Designation	Date of Inspection	Technology	Vendor	No. of Ext Metal Loss	No. of Ext ML On/Near Seam	No. of Int Metal Loss	No. of Dents	No. of Seam ML Anomalies	No. of Repair Digs
CA-324 Las Flores Canyon to Gaviota	6/18/2007	Def+MFL+IMU	Rosen	386	N/A	237	0	N/A	13
	7/3/2012	Def+MFL+IMU	Rosen	1578	N/A	6	1	N/A	41
	5/6/2015	Def+MFL+IMU	Rosen	1747	N/A	0	6	N/A	25
	2/23/2022	CMFL	Baker Hughes	2489	415	151	8	330	TBD
	12/10/2022	UTWM	Baker Hughes	1603	N/A	205	N/A	N/A	TBD
CA-325A Gaviota to Sisquoc	1/1/2003	Def+MFL+IMU	Tuboscope	362	N/A	0	22	N/A	1
	3/20/2008	Def+MFL+IMU	Rosen	1772	N/A	4932	12	N/A	21
	4/21/2008	Def							
	5/8/2008	Def+MFL+IMU							
	4/29/2013	Def+MFL+IMU	Rosen	14152	N/A	21135	10	N/A	90
CA-325B Sisquoc to Pentland	10/1/1994	Unknown	Tuboscope	Unknown	Unknown	Unknown	Unknown	Unknown	N/A
	1/8/2003	Def+MFL	Tuboscope	295	N/A	0	9	N/A	N/A
	10/21/2006	Def+MFL	Tuboscope	162	N/A	0	4	N/A	2
	3/10/2012	Def+MFL	TDW	14459	N/A	27501	9	N/A	101
	6/12/2013	MFL							

Coating and Cathodic Protection System Information

The Las Flores Pipeline System is externally coated with the following coating system as illustrated in Figure B-7:

- Coal tar urethane (CTU) coating in intimate contact with the steel pipe
- Layer of rigid thermal polyurethane (PU) foam insulation
- Outer layer of polyethylene (PE) tape wrap

Figure B-7: External Coating System Diagram



Shrink sleeves, which provide a barrier between the steel pipeline and soil for corrosion prevention, are present at original construction pipeline field joints. The use of the PU foam and PE tape was selected at the time of original construction to minimize heat loss of the crude oil within the pipeline during transit. The pipeline system has an impressed-current cathodic protection (CP) system that was energized at the time of installation. The CP system consists of active rectifiers at Las Flores Canyon Station, Gaviota Station, and Sisquoc Station, a critical bond at Pentland, as well as over 140 test stations across the entire CA-324 and CA-325A/B pipeline. The PU insulation and PE tape wrap has the ability to shield the cathodic protection. As a result, the CP current may not reach the pipe surface to arrest corrosion in the limited instance the CTU coating becomes disbonded. As a result, despite ongoing operation of the cathodic protection system in compliance with applicable regulations, the pipeline remains at risk of corrosion under insulation (CUI).

The CP system remains active and provides a level of external corrosion deterrence, and it is highly effective on portions of the pipeline without insulation (e.g. FBE and epoxy-coated regions). Cathodic protection has and will continue to be implemented, tested, and maintained on the pipeline at appropriate levels and in compliance with applicable regulations. Additionally, the use of modern, advanced in-line inspection technologies, along with explicit integrity management programs and procedures for robust characterization, validation, and criteria for anomaly repair support supplemental integrity management steps that exceed regulatory corrosion protection requirements and enable safe, responsible operation. Comprehensive conditions for effective management of the threat of external corrosion are included in Sections 5 of this Application.

EXHIBIT C

September 27, 2024

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
Via Email: Joe.Tyler@fire.ca.gov; Daniel.Berlant@fire.ca.gov

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

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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www.EnvironmentalDefenseCenter.org

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

[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. <u>**OSFM Must Prepare a Subsequent EIR Before Approving the Restart Project.**</u>

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

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.

[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

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[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. <u>OSFM Should, and in Some Cases Must, Engage the Public Before Issuing Any Approvals Associated with the Restart Project.</u>

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.

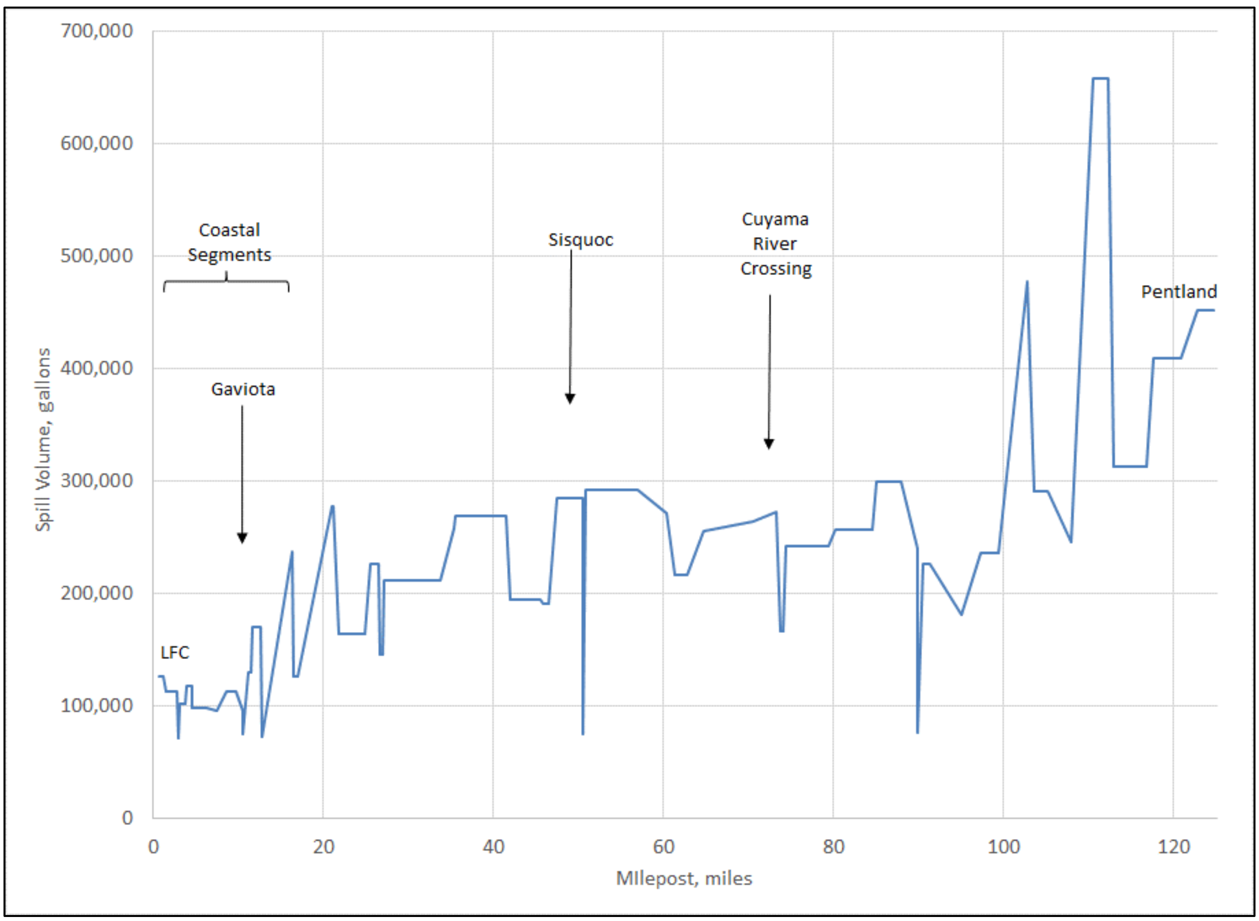
Crude Pipeline Spill Volumes

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.

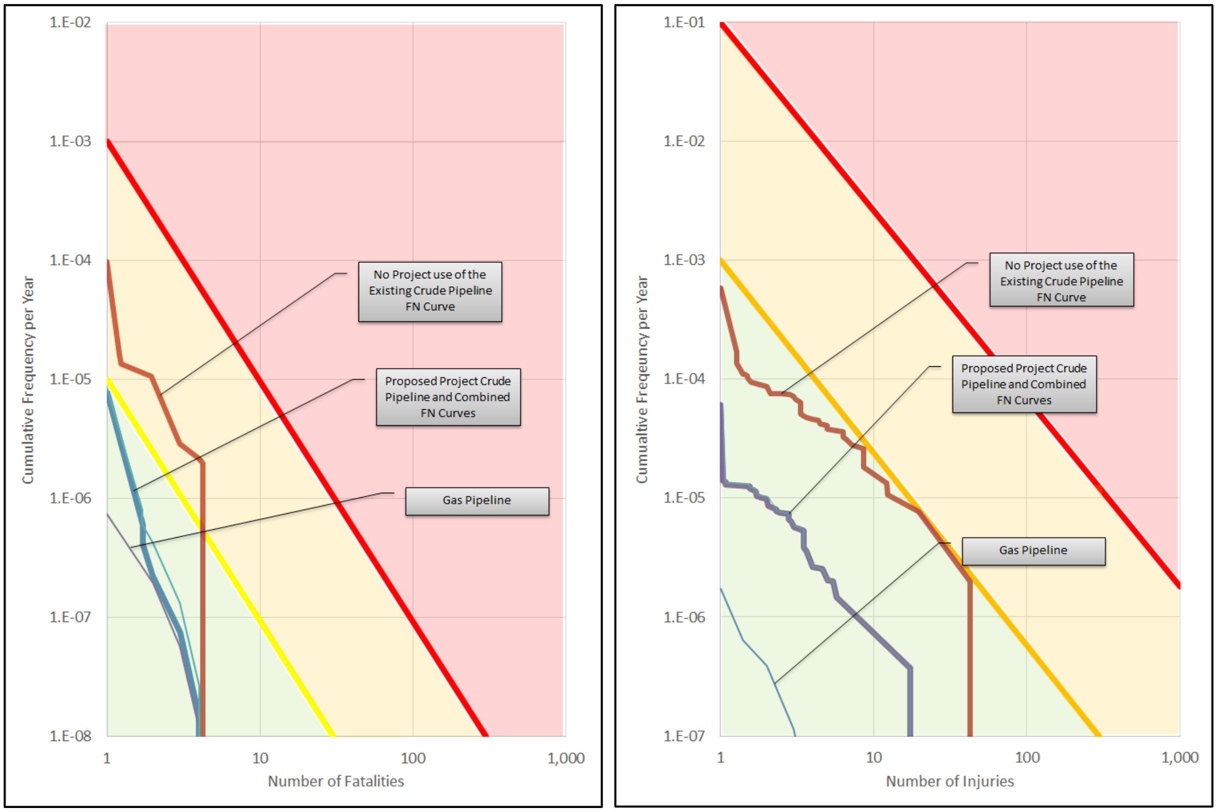
Gas Pipeline

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

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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.

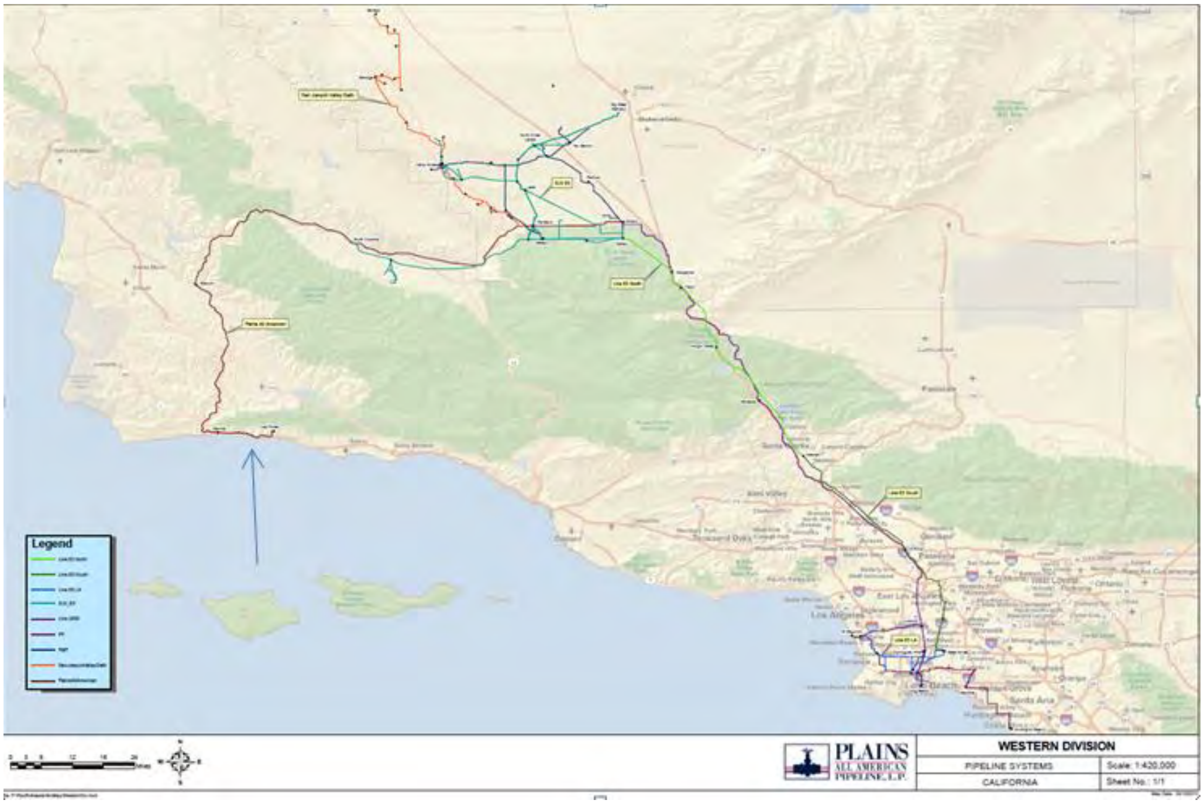

Figure 1. Map of Plains' Western Division Pipelines. The arrow points to the approximate release site on Line 901.

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]

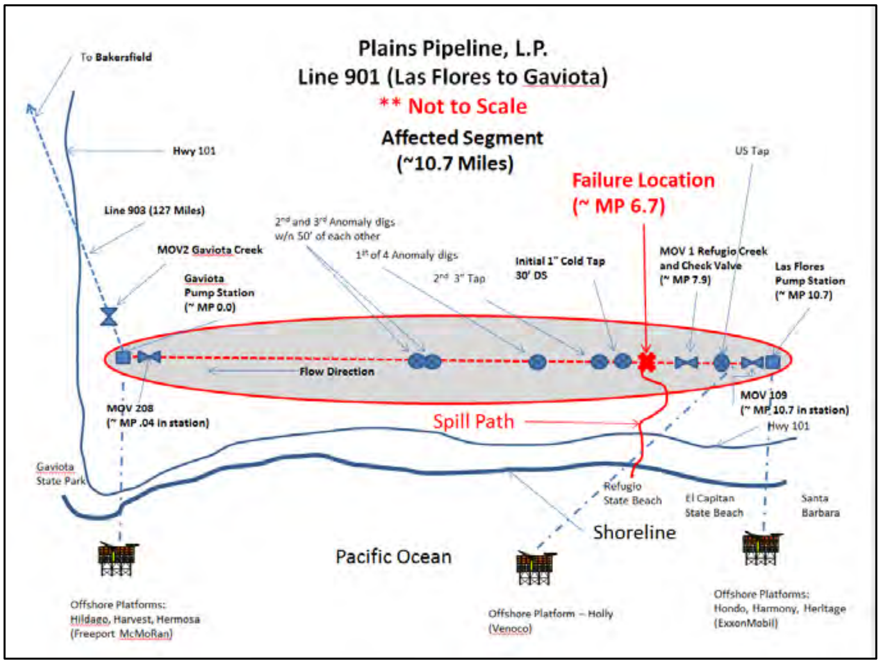

Figure 2. Schematic of Plains Pipeline, LP, Line 901 and spill path.

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.

EXHIBIT D

STATE CAPITOL
P.O. BOX 942849
SACRAMENTO, CA 94249-0115

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 found 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

[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.

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

EXHIBIT E

Accufacts Inc.

"Clear Knowledge in the Over Information Age"

Evaluation of Las Flores Pipeline System Startup Proposal

Prepared For

The Center for Biological Diversity
&
The Environmental Defense Center

December 20, 2024

Table of Contents

I. Executive summary and major findings

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

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

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

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

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

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

[4] PHMSA website, " Special Permits and State Waivers Overview," at https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-and-state-waivers-overview.

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

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

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

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[5] 49CFR§195 Subpart H - Corrosion Control.
[6] Consent Decree, Appendix B, "State Waivers for Line 901, 903 …..,".
[7] CA Code CCR 19§2111 – Risk Analysis.
[8] 49CFR§194 Response Plans for Onshore Oil Pipelines.

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

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

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

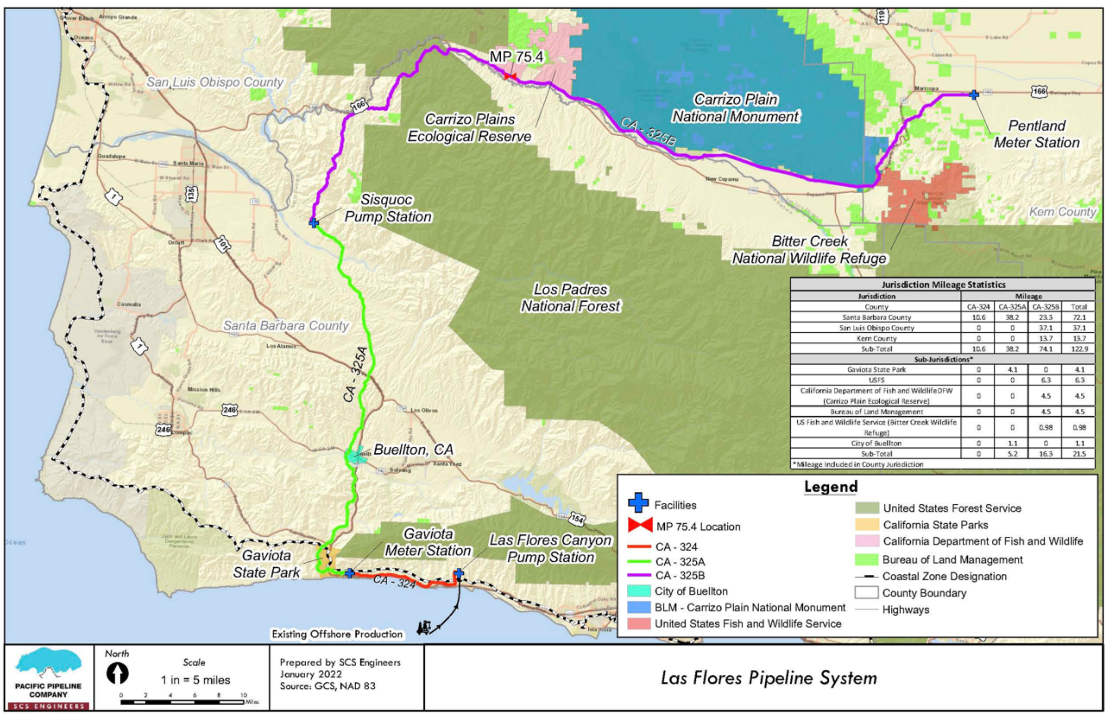
I am a chemical engineer with over fifty years of experience in the energy industry, including over 25 years as president of Accufacts Inc. ("Accufacts"). Accufacts provides independent expert consulting services to assist decision makers in making informed decisions concerning pipelines. Pipeline safety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

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

[9] Consent Decree, Appendix B & Appendix D.

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

III. A brief historical perspective



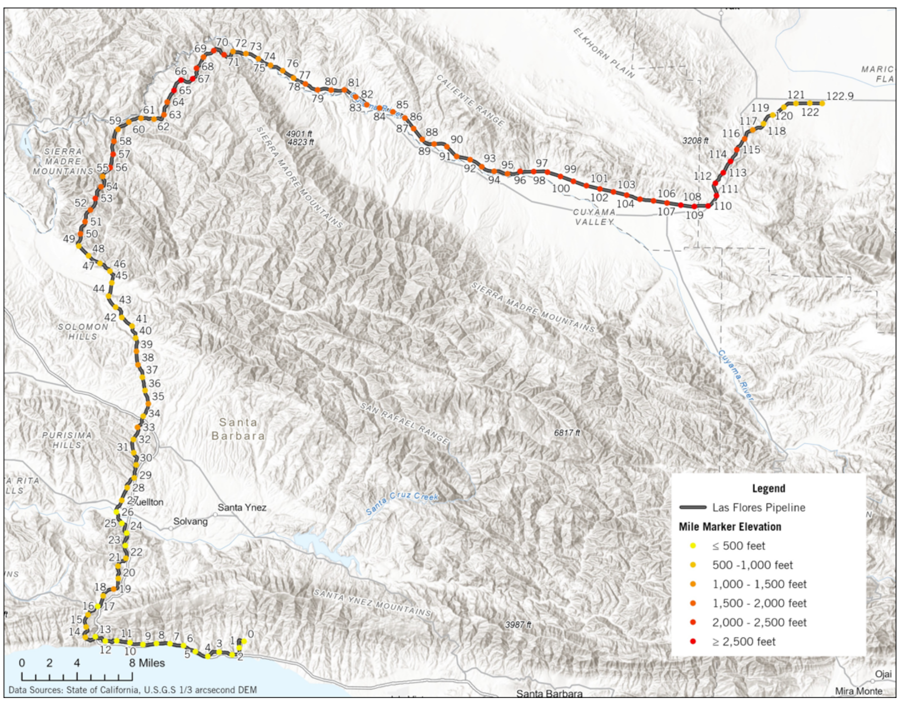
Jurisdiction Mileage Statistics				
Jurisdiction	Mileage			
County	CA-324	CA-325A	CA-325B	Total
Santa Barbara County	10.6	38.2	23.3	72.1
San Luis Obispo County	0	0	37.1	37.1
Kern County	0	0	13.7	13.7
Sub-Total	10.6	38.2	74.1	122.9
Sub-Jurisdictions*				
Gaviota State Park	0	4.1	0	4.1
USFS	0	0	6.3	6.3
California Department of Fish and WildlifeDFW (Carrizo Plain Ecological Reserve)	0	0	4.5	4.5
Bureau of Land Management	0	0	4.5	4.5
US Fish and Wildlife Service (Bitter Creek Wildlife Refuge)	0	0	0.98	0.98
City of Buellton	0	1.1	0	1.1
Sub-Total	0	5.2	16.3	21.5
*Mileage Included in County Jurisdiction				

Figure 1 – Overview of Pipelines

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

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

Figure 2 – Overview of Pipelines route with MPs estimated



IV. The Las Flores Pipeline System.

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

[10] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, "Failure Investigation Report, Plains Pipeline, LP, Line 901 Crude Oil Release, May 19, 2015 Santa Barbara County, California," May 2016. p.14 of 23.
[11] DNV-G Final Report, "Line 901 Release (5/15/15) Mechanical and Metallurgical Testing, - Report No: OAPUS309DNOR (PP136049)," September 18, 2015, p. iii.
[12] *Ibid.,* "Summary of Observations," p. vi.

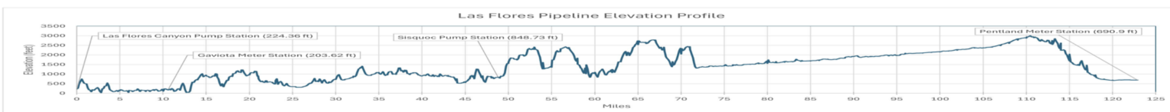
The Pipelines, formerly identified as Line 901/903 operated by Plains (aka Plains All American Pipeline L.P. and Plains Pipeline L.P.), represent a pipeline system of approximately 125 miles in length running from the Las Flores Canyon Pump Station (milepost 0) to the Pentland Metering (and Storage)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

According to the PHMSA Final Report on the 2015 rupture:

> Plains transports crude oil produced in federal and state waters off the coast of Santa Barbara, CA to inland refineries. Plains' pipeline is composed of two major pipeline sections: (1) Line 901, and (2) Line 903. Lines 901 and 903 were constructed in the late 1980s, hydrostatically tested in 1990, and went into crude oil service in 1992 and 1991, respectively. The pipelines are coated with coal tar urethane and covered with foam insulation which in turn is covered by a tape wrap over the insulation. Shrink wrap sleeves, which provide a barrier between the steel pipeline and soil for corrosion prevention, are present at all of the pipeline joints on Line 901 and multiple locations on Line 903. The pipelines carry high viscosity crude oil at a temperature of approximately 135 degrees Fahrenheit to facilitate transport. Lines 901 and 903 are controlled from the Plains Control Room's (PCR) California console in Midland, TX.
>
> Line 901 is a 24-inch diameter pipeline that extends approximately 10.7 miles in length from the Las Flores Pump Station to the Gaviota Pump Station; and (2) Line 903 is a 30-inch diameter pipeline that extends approximately 128 miles in length from the Gaviota Pump Station to the Emidio Pump Station, with intermediate stations at Sisquoc Mile Post (MP) 38.5 and Pentland (MP 114.57). There is a delivery point into Line 901 from Venoco's Line 96 located approximately 2 miles downstream of the Las Flores Station. All of Line 901 crude oil throughput enters Line 903. Line 901 was manufactured of low carbon steel by Nippon Steel in Japan in 1986. Line 901's pipe specifications are API 5L, Grade X-65 pipe, 0.344-inch wall thickness, with a high frequency-electric resistance welded (HF-ERW) long seam. The line was hydrotested to 1,686 pounds per square inch gauge (psig) on November 25, 1990. There are additional crude oil lines coming in and out of Pentland Station with numerous tanks at that station used to blend different crude oils for delivery further downstream. At Emidio Station crude oil is delivered to above-

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

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



PHMSA provided additional information related to Line 903:

> (2) Line 903 is a 30-inch diameter pipeline that extends approximately 128 miles in length from the Gaviota Pump station to the Emidio Pump Station, with intermediate stations at Sisquoc Mile Post (MP) 38.5 and Pentland (MP 114.57). [14]
>
> Plains has informed PHMSA that Line 903 has insulation and shrink wrap sleeves on the girth welds similar to the Affected Pipeline {Line 901}.[15]

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

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

[13] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, "Failure Investigation Report, Plains Pipeline, LP, Line 901 Crude Oil Release, May 19, 2015 Santa Barbara County, California," May 2016, pp. 4 & 5 of 21.
[14] *Ibid.,* p. 4 of 21.
[15] PHMSA – In the Matter of Plains Pipeline, LP, Respondent, "Amendment No. 1 to the Corrective Action Order – CPF No. 5-2015-5011H," p. 2.
[16] CA Code CCR 19§2111 – Risk Analysis (2) Pipeline Description (A).

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

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

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

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

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

1) Hydrotesting assessments.

Properly performed hydrotesting can be an important pipeline integrity assessment tool that proofs a pipeline's fitness for service to safely operate at MOP at the time of the hydrotest. Hydrotesting involves shutting down a pipeline and filling a pipeline segment with water. Proof of pipeline integrity or fitness for service testing is verified by carefully increasing water pressure with a water injection pump after air has been removed and the pipeline segment temperature stabilized. While federal pipeline safety regulations for liquid transmission pipelines define a "Subpart E" hydrotest to establish or verify maximum operating pressure, or MOP, a term having specific meaning in regulation, the regulations are not specific on important parameters to ensure a quality hydrotest that doesn't damage the pipe. Minimum hydrotest pressures are established to verify the MOP at the time of the hydrotest, with sufficient pressure safety margin at the time of the hydrotest. A Subpart E hydrotest is a proof for fitness test that the pipeline, at the time of the test, can withstand pressures above the MOP with a certain margin of pressure safety.[17]

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

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

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

[17] 49CFR§195.304 Test pressure
[18] Consent Decree, Appendix B (4) Integrity Management.

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

2) ILI assessments.

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

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[19] Los Angeles Times article by Tony Briscoe, "*Plan to restart pipeline sparks anger*," Front page, October 20, 2024.
[20] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration, "Failure Investigation Report, Plains Pipeline, LP, Line 901 Crude Oil Release, May 19, 2015 Santa Barbara County, California," May 2016. p.13 of 21.

Some forms of ILI technology to identify certain pipeline threats, if properly managed, can be superior to hydrotesting as they may identify some threats well before they go to failure. As too clearly demonstrated, however, in the May19, 2015 Line 901 rupture, ILI cannot address all forms of external corrosion threat that are likely to exist on the Pipelines because of their poor design, their unique high temperature operation, and ineffectiveness of CP. If a corrosion ILI tool can be utilized within the limits of the pig vendor specification (i.e., such as maintaining pig speed within the operating pipeline), and if the ILI tool run is independently field verified, some ILI tools can be a superior form of assessment for many types of pipeline threats, such as general internal and external corrosion (i.e. wall-thinning) if prudently managed. The more specialized forms of corrosion, cracking and pitting, or corrosion within dents, however, can be much more challenging as ILI tools and their related engineering critical assessments still have technical limits. ILI tool vendors place specific limitations on their various tools, and it is important that the pipeline operator follow such restrictions that can easily invalidate an ILI tool run reading or result. ILI runs in hilly terrain, such as that which exist with the Pipelines (See Figure 3) can be quite challenging for ILI tools that can easily exceed multiple tons in weight as gravity never shuts off.

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

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

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

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

The PHMSA Final Report stated:

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

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

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

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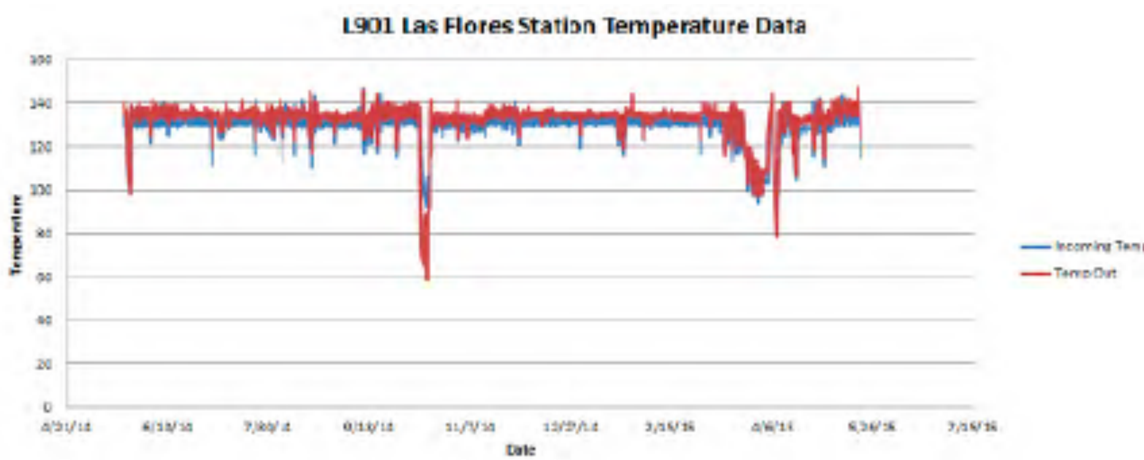
[21] *Ibid*, p. 14 of 21.
[22] *Ibid.,* p. 14 of 21.

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

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

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



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

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

[23] *Ibid.,* "Figure 23, L901 Las Flores Station Temperature Data," p. 375 of 510.

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

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

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

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

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

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

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

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

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

X. Conclusion.

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

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

Richard B. Kuprewicz

Richard B. Kuprewicz
President
Accufacts Inc.

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

Curriculum Vitae.

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Profile:

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

Employment:

Accufacts Inc. **1999 – Present**

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

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

Alaska Anvil Inc. **1993 – 1999**

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

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

ARCO Transportation Alaska, Inc. **1991 - 1993**

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

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

ARCO Transportation Co. **1989 – 1991**

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

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

Four Corners Pipeline Co. 1985 – 1989

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

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

Arco Product CQC Kiln 1985

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

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

Arco Products Co. 1981 - 1985

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

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

Arco Products Co. 1977 - 1981

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

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

Arco Products Co. 1973 - 1977

Operating Supervisor and Process Engineer for various major refinery complexes.

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

Qualifications:

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

Committee members are appointed by the Secretary of Transportation.

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

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

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

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

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

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

Education:

MBA (1976)	Pepperdine University, Los Angeles, CA
BS Chemical Engineering (1973)	University of California, Davis, CA
BS Chemistry (1973)	University of California, Davis, CA

Publications in the Public Domain:

1. "An Assessment of First Responder Readiness for Pipeline Emergencies in the State of Washington," prepared for the Office of the State Fire Marshall, by Hanson Engineers Inc., Elway Research Inc., and Accufacts Inc., and dated June 26, 2001.

2. "Preventing Pipeline Failures," prepared for the State of Washington Joint Legislative Audit and Review Committee ("JLARC"), by Richard B. Kuprewicz, President of Accufacts Inc., dated December 30, 2002.

3. "Pipelines - National Security and the Public's Right-to-Know," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated May 14, 2003.

4. "Preventing Pipeline Releases," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated July 22, 2003.

5. "Pipeline Integrity and Direct Assessment, A Layman's Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated November 18, 2004.

6. "Public Safety and FERC's LNG Spin, What Citizens Aren't Being Told," jointly authored by Richard B. Kuprewicz, President of Accufacts Inc., Clifford A. Goudey, Outreach Coordinator MIT Sea Grant College Program, and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated May 14, 2005.

7. "A Simple Perspective on Excess Flow Valve Effectiveness in Gas Distribution System Service Lines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated July 18, 2005.

8. "Observations on the Application of Smart Pigging on Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated September 5, 2005.

9. "The Proposed Corrib Onshore System - An Independent Analysis," prepared for the Centre for Public Inquiry by Richard B. Kuprewicz, dated October 24, 2005.

10. "Observations on Sakhalin II Transmission Pipelines," prepared for The Wild Salmon Center by Richard B. Kuprewicz, dated February 24, 2006.

11. "Increasing MAOP on U.S. Gas Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2006. This paper was also published in the June 26 and July 1, 2006 issues of the Oil & Gas Journal and in the December 2006 issue of the UK Global Pipeline Monthly magazines.

12. "An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick," prepared for the Friends of Rockwood Park, by Richard B. Kuprewicz, dated September 16, 2006.

13. "Commentary on the Risk Analysis for the Proposed Emera Brunswick Pipeline Through Saint John, NB," by Richard B. Kuprewicz, dated October 18, 2006.

14. "General Observations On the Myth of a Best International Pipeline Standard," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2007.

15. "Observations on Practical Leak Detection for Transmission Pipelines – An Experienced Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated August 30, 2007.

16. "Recommended Leak Detection Methods for the Keystone Pipeline in the Vicinity of the Fordville Aquifer," prepared for TransCanada Keystone L.P. by Richard B. Kuprewicz, President of Accufacts Inc., dated September 26, 2007.

17. "Increasing MOP on the Proposed Keystone XL 36-Inch Liquid Transmission Pipeline," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated February 6, 2009.

18. "Observations on Unified Command Drift River Fact Sheet No 1: Water Usage Options for the current Mt. Redoubt Volcano threat to the Drift River Oil Terminal," prepared for Cook Inletkeeper by Richard B. Kuprewicz, dated April 3, 2009.

19. “Observations on the Keystone XL Oil Pipeline DEIS,” prepared for Plains Justice by Richard B. Kuprewicz, dated April 10, 2010.

20. “PADD III & PADD II Refinery Options for Canadian Bitumen Oil and the Keystone XL Pipeline,” prepared for the Natural Resources Defense Council (NRDC), by Richard B. Kuprewicz, dated June 29, 2010.

21. “The State of Natural Gas Pipelines in Fort Worth,” prepared for the Fort Worth League of Neighborhoods by Richard B. Kuprewicz, President of Accufacts Inc., and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated October, 2010.

22. “Accufacts’ Independent Observations on the Chevron No. 2 Crude Oil Pipeline,” prepared for the City of Salt Lake, Utah, by Richard B. Kuprewicz, dated January 30, 2011.

23. “Accufacts’ Independent Analysis of New Proposed School Sites and Risks Associated with a Nearby HVL Pipeline,” prepared for the Sylvania, Ohio School District, by Richard B. Kuprewicz, dated February 9, 2011.

24. “Accufacts’ Report Concerning Issues Related to the 36-inch Natural Gas Pipeline and the Application of Appleview, LLC Premises: 7009 and 7010 River Road, North Bergen, NJ,” prepared for the Galaxy Towers Condominium Association Inc., by Richard B. Kuprewicz, dated February 28, 2011.

25. “Prepared Testimony of Richard B. Kuprewicz Evaluating PG&E’s Pipeline Safety Enhancement Plan,” submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012.

26. “Evaluation of the Valve Automation Component of PG&E’s Safety Enhancement Plan,” extracted from full testimony submitted on behalf of The Utility Reform Network (TURN), by Richard B.Kuprewicz, Accufacts Inc., dated January 31, 2012, Extracted Report issued February 20, 2012.

27. “Accufacts’ Perspective on Enbridge Filing to NEB for Modifications on Line 9 Reversal Phase I Project,” prepared for Equiterre Canada, by Richard B. Kuprewicz, Accufacts Inc., dated April 23, 2012.

28. “Accufacts’ Evaluation of Tennessee Gas Pipeline 300 Line Expansion Projects in PA & NJ,” prepared for the Delaware RiverKeeper Network, by Richard B. Kuprewicz, Accufacts Inc., dated June 27, 2012.

29. “Impact of an ONEOK NGL Pipeline Release in At-Risk Landslide and/or Sinkhole Karst Areas of Crook County, Wyoming,” prepared for landowners, by Richard B. Kuprewicz, Accufacts Inc., and submitted to Crook County Commissioners, dated July 16, 2012.

30. “Impact of Processing Dilbit on the Proposed NPDES Permit for the BP Cherry Point Washington Refinery,” prepared for the Puget Soundkeeper Alliance, by Richard B. Kuprewicz, Accufacts Inc., dated July 31, 2012.

31. “Analysis of SWG’s Proposed Accelerated EVPP and P70VSP Replacement Plans, Public Utilities Commission of Nevada Docket Nos. 12-02019 and 12-04005,” prepared for the State of Nevada Bureau of Consumer Protection, by Richard B. Kuprewicz, Accufacts Inc., dated August 17, 2012.

32. “Accufacts Inc. Most Probable Cause Findings of Three Oil Spills in Nigeria,” prepared for Bohler Advocaten, by Richard B. Kuprewicz, Accufacts Inc., dated September 3, 2012.

33. “Observations on Proposed 12-inch NGL ONEOK Pipeline Route in Crook County Sensitive or Unstable Land Areas,” prepared by Richard B. Kuprewicz, Accufacts Inc., dated September 13, 2012.

34. “Findings from Analysis of CEII Confidential Data Supplied to Accufacts Concerning the Millennium Pipeline Company L.L.C. Minisink Compressor Project Application to FERC, Docket No. CP11-515-000,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Minisink Residents for Environmental Preservation and Safety (MREPS), dated November 25, 2012.

35. “Supplemental Observations from Analysis of CEII Confidential Data Supplied to Accufacts Concerning Tennessee Gas Pipeline’s Northeast Upgrade Project,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Delaware RiverKeeper Network, dated December 19, 2012.

36. “Report on Pipeline Safety for Enbridge’s Line 9B Application to NEB,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Equiterre, dated August 5, 2013.

37. “Accufacts’ Evaluation of Oil Spill Joint Investigation Visit Field Reporting Process for the Niger Delta Region of Nigeria,” prepared by Richard B. Kuprewicz for Amnesty International, September 30, 2013.

38. “Accufacts’ Expert Report on ExxonMobil Pipeline Company Silvertip Pipeline Rupture of July 1, 2011 into the Yellowstone River at the Laurel Crossing,” prepared by Richard B. Kuprewicz, November 25, 2013.

39. “Accufacts Inc. Evaluation of Transco’s 42-inch Skillman Loop submissions to FERC concerning the Princeton Ridge, NJ segment,” prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated June 26, 2014, and submitted to FERC Docket No. CP13-551.

40. Accufacts report “DTI Myersville Compressor Station and Dominion Cove Point Project Interlinks,” prepared by Richard B. Kuprewicz for Earthjustice, dated August 13, 2014, and submitted to FERC Docket No. CP13-113-000.

41. “Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco’s Leidy Southeast Expansion Project,” prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated September 3, 2014, and submitted to FERC Docket No. CP13-551.

42. Accufacts’ “Evaluation of Actual Velocity Critical Issues Related to Transco’s Leidy Expansion Project,” prepared by Richard B. Kuprewicz for Delaware Riverkeeper Network, dated September 8, 2014, and submitted to FERC Docket No. CP13-551.

43. “Accufacts’ Report to Portland Water District on the Portland – Montreal Pipeline,” with Appendix, prepared by Richard B. Kuprewicz for the Portland, ME Water District, dated July 28, 1014.

44. “Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco’s Leidy Southeast Expansion Project,” prepared by Richard B. Kuprewicz and submitted to FERC Docket No. CP13-551.

45. Review of Algonquin Gas Transmission LLC’s Algonquin Incremental Market (“AIM Project”), Impacting the Town of Cortlandt, NY, FERC Docket No. CP14-96-0000, Increasing System Capacity from 2.6 Billion Cubic Feet (Bcf/d) to 2.93 Bcf/d,” prepared by Richard B. Kuprewicz, and dated Nov. 3, 2014.

46. Accufacts’ Key Observations dated January 6, 2015 on Spectra’s Recent Responses to FERC Staff’s Data Request on the Algonquin Gas Transmission Proposal (aka “AIM Project”), FERC Docket No. CP 14-96-000) related to Accufacts’ Nov. 3, 2014 Report and prepared by Richard B. Kuprewicz.

47. Accufacts’ Report on Mariner East Project Affecting West Goshen Township, dated March 6, 2015, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.

48. Accufacts’ Report on Atmos Energy Corporation (“Atmos”) filing on the Proposed System Integrity Projects (“SIP”) to the Mississippi Public Service Commission (“MPSC”) under Docket No. 15-UN-049 (“Docket”), prepared by Richard B. Kuprewicz, dated June 12, 2015.

49. Accufacts’ Report to the Shwx’owhamel First Nations and the Peters Band (”First Nations”) on the Trans Mountain Expansion Project (“TMEP”) filing to the Canadian NEB, prepared by Richard B. Kuprewicz, dated April 24, 2015.

50. Accufacts Report Concerning Review of Siting of Transco New Compressor and Metering Station, and Possible New Jersey Intrastate Transmission Pipeline Within the Township of Chesterfield, NJ (“Township”), to the Township of Chesterfield, NJ, dated February 18, 2016.

51. Accufacts Report, “Accufacts Expert Analysis of Humberplex Developments Inc. v. TransCanada Pipelines Limited and Enbridge Gas Distribution Inc.; Application under Section 112 of the National Energy Board Act, R.S.C. 1985, c. N-7,” dated April 26, 2016, filed with the Canadian Nation Energy Board (NEB).

52. Accufacts Report, “ A Review, Analysis and Comments on Engineering Critical Assessments as proposed in

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

53. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing to the Mississippi Public Utilities Staff, "Accufacts Review of Atmos Spending Proposal 2017 – 2021 (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 15, 2016.

54. Accufacts Report, "Accufacts Review of the U.S. Army Corps of Engineers (USACE) Environmental Assessment (EA) for the Dakota Access Pipeline ("DAPL")," prepared for Earthjustice by Richard B. Kuprewicz, dated October 28, 2016.

55. Accufacts' Report on Mariner East 2 Expansion Project Affecting West Goshen Township, dated January 6, 2017, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.

56. Accufacts Review of Puget Sound Energy's Energize Eastside Transmission project along Olympic Pipe Line's two petroleum pipelines crossing the City of Newcastle, for the City of Newcastle, WA, June 20, 2017.

57. Accufacts Review of the Draft Environmental Impact Statement for the Line 3 Pipeline Project Prepared for the Minnesota Department of Commerce, July 9, 2017, filed on behalf of Friends of the Headwaters, to Minnesota State Department of Commerce for Docket Nos. CN-14-916 & PPL-15-137.

58. Testimony of Richard B. Kuprewicz, president of Accufacts Inc., in the matter West Goshen Township and Concerned Citizens of West Goshen Township v. Sunoco Pipelines, L.P. before the Pennsylvania Public Utilities Commission, Docket No. C-2017-2589346, on July 18, 2017, on Behalf of West Goshen Township and Concerned Citizens of West Goshen Township.

59. Direct Testimony of Richard B. Kuprewicz, president of Accufacts Inc., on Behalf of Friends of the Headwaters regarding Enbridge Energy, Limited Partnership proposal to replace and reroute an existing Line 3 to the Minnesota Office of Administrative Hearings for the Minnesota Public Utilities Commission (MPUC PL-9/CN-14-916 and MPUC PL-9/PPL-15-137), September 11, 2017 and October 23, 2017.

60. Direct Testimony of Richard B. Kuprewicz On Behalf of The District of Columbia Government, before the Public Service Commission of the District of Columbia, in the matter of the merger of AltaGas Ltd. and WGL Holdings, Inc., Formal Case No. 1142, September 29, 2017.

61. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2018 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated December 4, 2017.

62. Report to Hugh A. Donaghue, Esquire, Concord Township Solicitor, "Accufacts Comments on Adelphia Project Application to FERC (Docket No. CP18-46-000) as it might impact Concord Township," dated May 30, 2018.

63. Report to Mississippi Public Utilities Staff ("MPUS"), "Accufacts Review on Atmos Energy Corporation's Proposed Capital Budget for Fiscal Year 2019 related to System Integrity Program Spending (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 20, 2018.

64. Report to West Goshen Township Manager, PA, "Accufacts report on the repurposing of an existing 12-inch Sunoco pipeline segment to interconnect with the Mariner East 2 and Mariner East 2X crossing West Goshen Township," dated November 8, 2018.

65. Report to West Whiteland Township Manager, PA, "Accufacts Observations on Possible Pennsylvania State Pipeline Safety Regulations," prepared by Richard B. Kuprewicz, dated March 22, 2019.

66. Accufacts Public Comments on the Proposed Joint Settlement, BI&E v. Sunoco Pipeline L.P. ("SPLP"), Docket No. C-2018-3006534 ("Proposed Settlement"), submitted on August 15, 2019 to the Pennsylvania Public Utility Commission on the behalf of West Goshen Township as an intervener.

67. Report to West Whiteland Township Manager, Ms. Mimi Gleason, "Accufacts Perspective on Two Questions from West Whiteland's Board of Supervisors on Proposed Changes to ME 2 and ME 2X Construction/Operational Activities within West Whiteland," dated September 5, 2019."

68. Report to West Goshen Township Manager, Mr. Casey LaLonde, “Accufacts Report on the episode on the evening of 8-5-19 at the Mariner East Boot Road Pump Station (“Event”), Boot Road, West Goshen Township, PA,” dated September 16, 2019.

69. Provided direct testimony before the Arizona Corporation Commission, In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on Fair Value of the Properties of Southwest Gas Corporation Devoted to its Arizona Operations (Docket No. G-01551A-19-0055), testified on behalf of Utilities Division Arizona Corporation Commission, February 19, 2020.

70. Report to West Goshen Township Manager, Mr. Casey LaLonde, “Accufacts Report on the Mariner East 2X Pipeline Affecting West Goshen Township,” dated July 23, 2020.

71. Assisted the Commonwealth of Massachusetts, Office of the Attorney General in developing pipeline safety processes to be incorporated into the settlement agreement related to Columbia Gas’ sale of Assets to Eversource following the Merrimack Valley, Massachusetts overpressure event of September 13, 2018.

72. Report to Natural Resources Defense Council, Inc., “Accufacts’ Observations on the Use of Keystone XL Pipeline Pipe Exhibiting External Coating Deterioration Issues from Long Term Storage Exposure to the Elements,” October 1, 2020.

73. Report to Pennsylvania Public Utilities Commission (“PAPUC”), “Accufacts Comments on Proposed Pennsylvania Intrastate Liquid Pipeline Safety Regulations,” dated October 29, 2021, prepared for West Whiteland Township Board of Supervisors, West Whiteland Township, PA. Filed to PAPUC public web docket November 5, 2021 by West Whiteland Township under Reference Docket Number L-2019-3010267. Addresses suggested improvements in proposed pipeline safety rules for PA intrastate liquid transmission pipelines.

74. Submitted written testimony of Richard B. Kuprewicz on Behalf of Bay Mills Indian Community to ALJ Dennis Mack, dated December 14, 2021, in the matter of the Application of Enbridge Energy, Limited Partnership for Authority to Replace and Relocate the Segment of Line 5 Crossing the Straits of Mackinac into a Tunnel Beneath the Straits of Mackinac, before the State of Michigan Public Service Commission, U-20763.

75. Public presentation to New York State Indian Point Nuclear Facility Decommissioning Oversight Board on Holtec removal activities in proximity to Enbridge three Natural Gas Transmission Pipelines, March 17, 2022.

76. Report to Pipeline Safety Trust and Bold Alliance, “Accufacts’ Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.,” March 23, 2022.

77. Accufacts Inc., Public Presentation for the National Academies of Science Engineering Medicine and The Transportation Research Board, “To Committee on Criteria for Installing Automatic and Remote-Controlled Shutoff Valves on Existing Gas and Hazardous Liquid Transmission Pipelines,” 4/27/22.

78. Accufacts Inc, “6/13/22 Webinar to Illinois Emergency Responders, Healthcare Providers, & Local Officials on Responses to CO_2 Transmission Pipeline Releases,“ 6/13/22.

79. Accufacts Report for Pipeline Safety Trust, “Safety of Hydrogen Transportation by Gas Pipelines,” 11/28/22.

80. Completed a series of testimonies related to Enbridge’s Line 5 proposal to replace 2 – 20-inch diameter existing submerged pipelines currently lying across the bottom of the Straits of Mackinac with a 30-inch diameter grade X-70 pipeline, proposed to be installed in a 21-foot diameter concrete tunnel to be installed across the approximate 4-mile span of the Straits of Mackinac. Testified on Behalf of the Bay Mill Indian Community before the State of Michigan Public Service Commission, Docket U-20763, in opposition to this very poorly designed proposal/installation allowing for movement of the pipeline on rollers within the tunnel. Final testimony to the docket submitted May 19, 2023. This is the only pipeline proposal I am aware of in the world that would place a crude oil and liquid propane pipeline, especially a 30-inch diameter pipeline, within a tunnel.

81. Issued to Ms. Niroop Srivatsa, City Manager, “Accufacts Report for the City of Lafayette on the Status of the Tree Assessment Process with PG&E,” indicating most of the trees identified for removal by PG&E risk management

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

82. Issued Direct Testimony to Illinois Commerce Commission ("ICC") on the Navigator Heartland Greenway LLC Application for a Carbon Dioxide Transportation and Sequestration pipeline, under Docket 23-0161, on behalf of Citizens Against Heartland Pipeline ("CAHGP"), McDonough County, Christian County and Hancock County (the "Counties") (jointly, "Citizen and County Intervenors" of "CCI"), raising serious questions as to PHMSA's recent assertions of pipeline safety jurisdiction, and underscoring the ICC's authority for pipeline siting jurisdiction of said pipeline proposal in the State of Illinois, filed June15, 2023. Applicant has terminated their application.

83. Issued Direct Testimony to Illinois Commerce Commission ("ICC") on the WOLF Carbon Solutions US LLC Application for a Carbon Dioxide Transportation and Sequestration pipeline, under Docket 23-0475, for a certificate of authority to construct and operate a carbon dioxide pipeline and when necessary to take interest in property as provided by law of eminent domain, testifying on Behalf of Citizens Against Predatory Pipelines ("CAPP"): 1) identifying serious inadequacies in PHMSA's pipeline safety regulations, 2) explaining why the Commission should require pipeline temperature profiles 3) detailing why DNV-RP-F104 is not relevant to this filing and 4) underscoring the ICC's authority to require additional critical information from the Applicant in this matter, filed October 24, 2023. Applicant has withdrawn their submission to the Commission.

84. Provided general summary, main observations/concerns, on "Draft Environmental Impact Statement: Otter Tail to Wilkin Carbon Dioxide Pipeline Project" submitted to Minnesota Public Utilities Commission regarding Summit Carbon Solutions, LLC proposed 28 mile long 4-inch diameter CO_2 liquid transmission pipeline ("Otter Tail Pipeline") within Minnesota, PUC Docket No. IP-7093/PPL-22-422, provided to Clean Up the River Environment ("CURE") on 1/29/2024.

85. Issued to EarthJustice, "Observations concerning Kern County's Draft Environmental Impact Report ("DEIR") on the TerraVault I Carbon Capture and Storage Project ("Project")," dated February 26, 2024, "Observations concerning Kern County's Recent Recirculated Draft Environmental Impact Report ("RDEIR") on the TerraVault I Carbon Capture and Storage Project ("Project")," dated July 17, 2024, and "Evaluation of Kern County Response to Comments and Final Recirculated Environmental Impact Report on the TerraVault I Carbon Capture and Storage Project, dated October 15, 2024. The Project situated in Kern County is proposed by the California Resources Corporation to separate a portion of the pre-combustion Elk Hills field gas production, treat and inject via liquid transmission pipelines, CO_2 into two sequestration injection wells within the Elk Hill oil field. The reports identify many technical gaps in filings to Kern County.

86. Issued for the Tribal Partnerships Program, "Observations on the U.S. Army Corps of Engineers Draft Environmental Assessment, Clean Water Act Section 404(b)(1) Guidelines Evaluation, and Public Interest Review (collectively referenced as "DCDD") for the Enbridge Line 5 Wisconsin Segment Relocation Project ("Project"), dated May 2024," report dated July 31, 2024 affecting the Bad River Band of the Lake Superior Tribe of Chippewa Indians reservation.

EXHIBIT F

DEPARTMENT OF FORESTRY AND FIRE PROTECTION
OFFICE OF THE STATE FIRE MARSHAL
P.O. Box 944246
Sacramento, California 94244-2460
(916) 568-3800
Website: www.fire.ca.gov

CERTIFIED MAIL No: 9589-0710-5270-1475-5353-08

December 17, 2024

Lance Yearwood
Vice President
Sable Offshore Corp
845 Texas Avenue, Suite 2920
Houston, Texas 77002

SUBJECT: LETTER OF DECISION ON THE STATE WAIVER REQUEST FOR LIMITED EFECTIVENESS OF CATHODIC PROTECTION ON THERMALLY INSULATED PIPELINE AND CORROSION OF OR ALONG A LONGITUDINAL SEAM WELD (CA-324)

Operator: Sable Offshore Corp
OPID# 40851
845 Texas Avenue, # 2920
Houston, Texas 77002

Pipeline: OSFM Line ID 0015 - 10.86 miles (Las Flores Canyon to Gaviota) of Sable Offshore Corp CA-324 (OSFM Line ID 0015) located in Santa Barbara County, California as described in the request of state waiver dated April 24, 2024

Dear Mr. Yearwood:

The Office of the State Fire Marshal (OSFM) received Sable Offshore Corp's (*Sable*) state waiver request (*Application*) on April 24, 2024, in accordance with the terms of the Consent Decree (CD) between Plains Pipeline, L.P. and the United States of America and the People of the State of California, DOJ Case REF. NO. 90-5-1-1-1130 (Appendix B, Article 1.1.D).

In addition, Sable requested a regulatory relief from Title 49 Code of Federal Regulations (49 C.F.R.), § 195.452(h)(4)(iii)(H) *Corrosion of or along a longitudinal seam weld* for Sable CA-324.

Sable explained that its goal is to appropriately manage the risk of corrosion under insulation that may occur as a result of inadequate cathodic protection due to the shielding effects of the polyurethane foam and the polyethylene tape wrap. Sable described the measures it has taken to address this risk and implemented and proposed a number of additional measures designed to mitigate the risk of corrosion under insulation that may result from potential ineffective cathodic protection (CP).

Sable provided the OSFM with its proposed measures to mitigate the risk of corrosion under insulation. Sable also provided the OSFM information from the completed in-line inspections and additional data requested by our office. The OSFM Pipeline Safety Engineers have reviewed the materials provided and have been in communication with the United States Department of Transportation (USDOT), Pipeline and Hazardous Materials Safety Administration (PHMSA) Engineering and Research Division to incorporate PHMSA's recommended conditions into the state waiver.

The OSFM has regulatory jurisdiction over the safety standards and practices of intrastate hazardous liquid pipeline transportation within California. As a Pipeline Safety Program that is certified under 49 USC § 60105, the OSFM may grant a state waiver with a pipeline safety regulation adopted by the state of California. Title 49 C.F.R., Part 195 was adopted by reference as it relates to hazardous liquid pipelines within Title 19 California Code of Regulations (19 CCR), Section 2000.

This state waiver applies to Sable's Line CA-324 (OSFM Line ID 0015) which consists of a 10.86 mile long, 24-inch outside diameter pipeline segment with the origin and termination points as described in the application. The pipeline is located in Santa Barbara, California and shall be referred herein as *CA-324.*

The state waiver shall not become effective until (1) PHMSA issues an Order approving the waiver or stating it has no objection to the waiver or (2) PHMSA takes no action on the waiver within sixty (60) days after receiving the Letter of Decision from the OSFM.

The state waiver is limited to a term of no more than ten (10) years from the date it becomes effective, which shall be considered as the date of issuance. The OSFM may terminate the state waiver under conditions detailed below.

Applicable Regulations

The OSFM hereby grants this state waiver for CA-324, provided that Sable complies with the specific requirements in this state waiver and any additional conditions outlined by PHMSA. The pipeline must be operated and maintained in accordance with the CD, these state waiver conditions and 49 C.F.R. Part 195, with the exception of 49 C.F.R. §195.452(h)(4)(iii)(H). In the event of a conflict between the state waiver conditions and the applicable requirements under 49 C.F.R. Part 195, the state waiver conditions control.

Should additional federal or State statutory or regulatory requirements come into effect following the implementation of this state waiver, CA-324 shall be subject to those requirements except where they are in conflict with the State Waiver or the safe operation of the pipeline.

General Conditions

1. The pipeline can only be used to transport crude oil as stated in the application.
2. The maximum operating pressure (MOP) of CA-324 cannot exceed 1003 pounds per square inch gauge (psig).
3. The maximum operating temperature of the crude oil that transports in CA-324 must not exceed 140 Fahrenheit for more than 12 consecutive hours.
4. Prior to startup, Sable must develop and implement procedures for the conditions and requirements described in the state waiver.
5. This state waiver does not relieve Sable from other requirements under 49 C.F.R. Part 195 or the Elder California Pipeline Safety Act of 1981 other than contained herein.
6. This state waiver does not relieve Sable from any requirements imposed by the Consent Decree (United States District Court Central District of California Civil Action No. 2:20-cv-02415).
7. In-line inspection must include:
    a. Use of a tool that is at least capable of reliably detecting and identifying cluster corrosion and general corrosion. Definition of cluster and general corrosion is as follows:
        i. Cluster means two or more adjacent metal loss features in the wall of the pipe or weld that may interact based on interaction criteria.
        ii. General corrosion means uniform or gradually varying loss of wall thickness over an area.
    b. Use of a tool that is at least capable of reliably detecting and sizing corrosion at a 90 percent probability of detection (POD) and probability of identification (POI).
    c. Use of a tool that is at least capable of reliably detecting and sizing cracks or crack-like anomalies at a 90 percent POD and POI.
8. Prior to placing CA-324 in operation, Sable must perform fracture toughness tests on the existing 24” pipe from CA-324 in accordance with ASTM E1820-23B Standard Test Method for Measurement of Fracture Toughness. All of the test specimens must be from the predominant existing 24” pipe, specifically API 5L X65 HF-ERW pipe with a nominal thickness of 0.344” that was manufactured by

Nippon Steel Corp. in the 1980s. At least three (3) separate tests must be performed to obtain the fracture toughness values of the pipe body, heat affected zone (HAZ)[1], and the HF-ERW long seam weld on the pipe to represent the fracture toughness of its CA-324 (i.e. three (3) samples for pipe body, three (3) samples for HAZ, and three (3) samples for the HF-ERW long seam weld). The lowest fracture toughness value must be applied to conditions 10, 30, 33, and 48. Sable may use pipe samples taken opportunistically during ongoing pipeline maintenance and repair efforts.[2]

9. All immediate and 180-day repair conditions that are listed in this state waiver must be evaluated and remediated prior to restarting CA-324. Sable must utilize Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) tools within seven (7) days of achieving initial steady state operation in accordance with an ILI survey schedule approved by OSFM. Sable must utilize the most recent Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) results when identifying these repair conditions.
10. Remaining strength of pipe calculation for all metal loss anomalies must be in accordance with the Modified B31G method as described in ASME B31G *Manual for Determining the Remaining Strength of Corroded Pipelines.* If ASME B31G 2012 Edition is used, then it must comply with the conditions in accordance with Section 1.2 and exclusions in accordance with Section 1.3 of ASME B31G 2012 Edition. However, if the metal loss anomaly intersects or is within one (1) inch (circumferentially) of the longitudinal seam weld, Sable must also calculate the predicted failure pressure of the anomaly by using the crack-like flaw evaluation method ASME FFS-1/API 579-1.
11. Sable must utilize cleaning pigs at regular intervals not to exceed a biweekly basis to maintain adequate cleanliness on the internal pipe wall of its CA-324.

Pressure Testing

12. Prior to placing the pipeline in operation, Sable must conduct a spike hydrostatic pressure test of the state waiver pipeline segments at a minimum pressure that is at least 1.5 times the MOP or 100% SMYS, for a minimum of 15 minutes after

[1] The heat affected zone (HAZ), as used in the state waiver, is defined as a 1-inch-wide area on either side of the longitudinal weld seam.
[2] Sable must submit all fracture toughness results to the OSFM prior to restarting the pipeline.

the spike test pressure is stabilized. Sable must field evaluate and remediate the following anomalies before performing the spike hydrostatic test on CA-324:

a. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.
b. All anomalies that have a predicted failure pressure less than or equal to 1.6 times MOP.

13. Immediately following the spike hydrostatic pressure test, Sable must conduct an 8-hour hydrostatic pressure test of the state waiver pipeline segments at a minimum of 1.25 times the MOP.
14. Sable must obtain the Test ID from the OSFM for each hydrostatic pressure test and have the approved independent testing firm forward separately the certified test results to the OSFM.
15. Each hydrostatic pressure test must be performed in accordance with the applicable requirements of 49 C.F.R., Part 195 Subpart E – Pressure Testing and monitored by an independent testing firm listed under the OSFM approved hydrostatic testing companies.
16. Failures resulting from the spike hydrostatic pressure test or the 8-hour strength test shall be immediately reported[3] to the OSFM via email at PipelineNotification@fire.ca.gov
Subject: OSFM State Waiver - Hydrotest Failure
17. Section(s) of the state waiver pipeline segments that failed during the required hydrotesting must be repaired by removing and replacing the failed section. The OSFM reserves the right to revoke the state waiver if failure(s) raise the concern that the pipeline cannot be safely operated.

In-Line Inspection (ILI) Assessment and Frequency

18. At least 90 days prior to performing in-line inspections of the state waiver segment, Sable shall provide the OSFM with a written notification to PipelineNotification@fire.ca.gov describing its assessment plan with the following information:
    a) Dates for integrity assessment
    b) In-line inspection tool(s) selected, in accordance with API Standard 1163 Section 5 and NACE SP0102[4] to assess the integrity of the subject pipe

[3] In addition to the OSFM reporting, Sable shall follow all additional state reporting requirements.
[4] Industry standards that are referenced in this state waiver must utilize the editions that are incorporated by referenced in Title 49 Part 195.3 unless another edition was explicitly specified.

segment(s) in which ILIs must be capable to detect and size wall loss, dents, internal corrosion, external corrosion, cracks and crack-like indications

c) In-line inspection tool vendor(s)
d) Required tool specifications including operational specifications and anomaly sizing tolerances
e) Tool validation methodology
f) Anomaly feature identification criteria and reporting thresholds – wall loss, dents, internal corrosion, external corrosion, cracks, and crack-like indications
g) Criteria used to identify locations for excavation and field verification
h) Non-destructive examination

19. Within seven (7) days prior to any anticipated ILI tool run, Sable must utilize extensive brush pigs and solvents (xylene or other chemicals) to ensure that the internal pipe wall does not have any corrosive products, wax, and bacteria buildup that may affect the ILI tool performance.
20. Metal Loss Tool(s)
    a. Initial ILI tool runs – Each year, during the first two (2) years of operating CA-324, Sable shall conduct at least two (2) ILIs using a UTWM tool with an inertial measurement unit (IMU). Sable shall compare both runs and evaluate all available information, including these tool runs and corresponding IMU data. Sable shall perform the UTWM tool run every six (6) months not to exceed nine (9) months. If a UTWM tool run is unsuccessful, Sable shall identify the limitations that prevented the UTWM tool run from being successful, consider changes to increase the likelihood of a successful UTWM tool run, and use best efforts to rerun the UTWM tool within 30 days.
    b. Subsequent ILI tool runs – After the first two (2) years of operating CA-324, Sable shall conduct at least one (1) Ultrasonic Wall Measurement tool (UTWM) each calendar year, not to exceed 15 months or the ILI assessment must be assessed at more frequent intervals if the remaining Failure Pressure Ratio will be less than 1.39 times MOP prior to the next ILI assessment, based upon anomaly growth estimates and pressure cycling. If any UTWM tool run is deemed to be unsuccessful, Sable shall document the reasons why the UTWM tool was unsuccessful, consider changes to increase the likelihood of a successful UTWM tool run, and must reassess the pipeline within 30 days after it was deemed to be unsuccessful. All metal loss tool runs must also utilize an Inertial Measurement Unit (IMU).
21. Crack Detection Tools - Sable shall conduct at least one (1) Ultrasonic Shear Wave Crack Detection (USCD) tool each calendar year, not to exceed 15

months[5] or ILI assessment must be assessed at more frequent intervals if condition 48 determined a shorter assessment interval.

a. These crack tool runs must utilize an Inertial Measurement Unit (IMU) and must be able to detect and size axial and circumferential cracks.
b. USCD Performance Specification Requirements
    i. The USCD tools must have a probability of detection that is ≥ 90% for axial and circumferential cracks.
    ii. The minimum crack depth that can be detected must be at least 1 mm for axial and circumferential cracks that are located in the base material.
    iii. The minimum crack depth that can be detected must be at least 2 mm for axial and circumferential cracks that are located in the weld.
    iv. The depth sizing accuracy for cracks must be ± 0.8 mm for axial cracks and ± 1 mm for circumferential cracks.

22. Dents and Pipe Deformation: Sable shall conduct a high-resolution deformation ILI tool with each UTWM.
23. Where any ILI tool fails to record data for 5% or more of the external and/or internal surface area of the inspected segment, reassess with the ILI tool to cover the area that is deemed to be inadequate data of the inspected segment. In addition, if the ILI tool travels at a speed that is outside the range of the tool velocity listed in the tool specification for 2% or more of the length of the inspected segment, Sable must rerun the ILI tool to reassess the pipeline segment in which the ILI tool velocity was outside of the specified tool velocity range.
24. All ILI tool runs must obtain the Test ID from the OSFM prior to run.
25. Sable must require its ILI tool vendor(s) to include in the vendor's inspection report all metal loss indications of 10% or greater, based on raw data, prior to adding in any correction for tool tolerance.
26. Sable must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool, in accordance with API Standard 1163 Second Edition and includes that tolerance in determining the size of each indication reported to Sable.
27. Sable must account for ILI tool tolerance and anomaly growth rates in scheduled response times, repairs, and future reassessment intervals. Sable must

[5] Sable may petition the OSFM to revise the reassessment interval for Crack Detection Tool(s) when sufficient evidence is available to determine if crack growth rates could support a longer reassessment interval. Changes to the reassessment interval are subject to OSFM and PHMSA approval.

document and justify the values used. Sable must demonstrate ILI tool tolerance accuracy for each ILI tool run by using calibration, excavations, and unity plots[6] that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). Sable must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently over-calling or under-calling, the remaining ILI features must be re-graded accordingly.

28. Prior to the ILI final report being received, Sable must perform at least four (4) separate validation digs that do not interact with each other. At a minimum, Sable must perform validation digs in accordance with Level 2 of API Standard 1163, "In-line Inspection System Qualification" (Second Edition, April 2013).

Discovery of Condition

29. The discovery date must be within 180 days of any ILI tool run for each type of ILI tool.

Immediate Repair Conditions[7]

30. A crack or crack-like anomaly that meets any of the following criteria:
    a. Crack or crack-like anomaly that is equal to or greater than 50% of pipe wall thickness.
    b. Crack or crack-like anomaly that has predicted failure pressure of less than 1.39 times the MOP as calculated using crack-like flaw evaluation method ASME FFS-1/API 579-1.
31. Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.39 times the MOP.
32. Any external cluster corrosion or external general corrosion that is located on the bottom half of the pipeline (below the 3 and 9 o'clock positions) where the

[6] A minimum of four (4) independent direct examination excavations must be used for unity plots.

[7] The criteria outlined in the state waiver is supplemental to the requirements set forth in *§195.452(h)(4)(i) Immediate repair conditions* and does not relieve Sable from complying with §195.452(h)(4)(i). All immediate repair conditions must be remediated with a permanent repair method.

remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.[8]

<u>180-Day Repair Conditions</u>[9]

33. A crack or crack-like anomaly that has predicted failure pressure of less than 1.5 times the MOP.
34. Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.
35. All internal or external metal loss anomalies that have an ILI reported depth of 40% or greater wall loss, including tool sizing tolerance for depth.[10]
36. For any crack (likely crack or possible crack) or crack-like anomaly, regardless of its dimensions, that interacts with metal loss anomalies and are within one (1) inch (circumferentially) of the longitudinal seam weld, Sable must integrate the ILI results from the most recent crack tool run and the most recent metal loss tool run before the discovery date deadline.

<u>Corrosion Growth Rate Analysis (CGRA)</u>

37. Sable must develop a CGRA procedure to annually calculate corrosion growth rates between successive ILI's (using most recent ILI compared to prior ILI) and perform pipeline remediations needed to assure the integrity of the pipeline is maintained.[11] The timing of pipeline remediations under this condition shall be based on the most recent calculation of short-term corrosion rates.
38. The CGRA procedure must include ILI data matching methods[12] to analyze data from successive ILI's, methodologies for growth rate calculations and errors from comparing ILI data.

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[8] Cluster means two or more adjacent metal loss features in the wall of the pipe or weld that may interact based on interaction criteria. General corrosion means uniform or gradually varying loss of wall thickness over an area.

[9] The criteria outlined in the state waiver is supplemental to the requirements set forth in *§195.452(h)(4)(iii) 180-day conditions* and does not relieve Sable from complying with §195.452(h)(4)(iii). All 180-day repair conditions must be remediated with a permanent repair method.

[10] For example, if the ILI tool reports a 31% metal loss anomaly and the tool sizing tolerance is ±10 for depth, then this anomaly is a 180-day repair condition since it can be considered as an external metal loss anomaly with 41% metal loss depth. If Sable is unable to remediate such indications within 180 days of discovery, Sable must notify the OSFM, temporarily reduce the operating pressure, and take further remedial action in accordance with 49 C.F.R. §195.452 until the indication is remediated or until otherwise authorized by OSFM.

[11] At a minimum, Sable must include signal matching between ILI data sets.

[12] If there are several matching techniques that can be used, Sable must utilize the most accurate method of comparing ILI data sets.

39. Sable must identify the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss.
40. When determining the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss, Sable must account for reported ILI depth, tool tolerance and corrosion growth rates[13].
41. All metal loss indications that are projected to reach a depth of 70% or greater wall loss prior to the next ILI, will become actionable and must be remediated before the next ILI.

Pressure Reduction

42. If Sable is unable to perform field evaluation and remediation of any required conditions within the time limit conditions specified in the state waiver, Sable must temporarily implement a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two (2) months prior to the date of inspection, until the anomaly is repaired.

In Field Direct Examination of Pipe

43. Direct examinations[14] of pipe must include appropriate non-destructive examination methods for cracking such as magnetic particle inspection (MPI), shear wave technology or phased array ultrasonic testing (PAUT).[15] PAUT must be used for sizing any crack or crack-like anomaly lengths and depths.
44. Permanent repairs of metal loss anomalies are required for any section of pipe with wall loss equal to or greater than 40% in accordance with repair method 1, 4b, or 5 of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition. However, the following additional conditions are applied if Sable chooses repair method 5 for metal loss anomalies:
    a. Method 5 must not be used on metal loss anomalies that are in the HAZ, girth weld, or longitudinal seam weld.

[13] Growth projections must use corrosion rates determined in accordance with the CGRA procedure. A default corrosion rate of 32 mpy must be used in determining projections, if corrosion rates determined by CGRA are less than the default value.
[14] Any time the pipeline is exposed for direct examination of an indication or to perform a repair, Sable must document the condition of the coating and carrier pipe (including anomalies) with photographs.
[15] Direct examinations for ILI reported crack or crack-like indications must include a magnetic particle inspection complimented by shear wave technology or inspection by phased array ultrasonic testing.

b. Sable must increase the metal loss anomaly's depth by 20% when they input it into the formula for calculating the number of wraps needed for repair method 5.
c. After the anomaly is repaired via repair method 5, Sable must monitor the anomaly's wall loss depth in subsequent UTWM tool runs. If the anomaly's wall loss depth increases by more than 15% of the wall thickness in the subsequent UTWM tool runs, Sable must repair this anomaly via repair method 1 or 4b of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition.

45. Permanent repairs are required for all cracks and/or crack-like anomalies discovered during direct examination, regardless of crack depth or crack length in accordance with repair method 1 or 4b of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition.
46. Sable must develop a coating repair procedure for excavated or remediated corrosion anomalies that prevents further external corrosion and seals transition areas from currently insulated pipe to newly coated sections. Any time a shrink sleeve or coating is exposed, remove the shrink sleeve and coating, investigate circumferentially and longitudinally along the pipe for external corrosion and coating deterioration, and recoat with two-part epoxy. Sable must recoat in accordance with their coating repair procedure.[16]
47. All external polyurethane foam and the polyethylene tape wrap on buried pipe that are exposed during the field evaluation must not be replaced with new insulation or polyethylene tape wrap.

<u>Integrity Management</u>

48. A fracture mechanics and pressure cycling evaluation is required for un-remediated cracks and crack-like indications detected by ILI or indirect inspection tools.
    a. Sable must determine the predicted failure pressure, failure stress pressure and crack growth of un-remediated cracks and crack-like anomalies in accordance with 49 C.F.R. §192.712(d)(1).
    b. Sable must perform a fatigue analysis using an applicable fatigue crack growth law or other technically appropriate engineering methodology in accordance with 49 C.F.R. §192.712(d)(2).
49. Sable must analyze a sample of additional indications of varying amounts of metal loss between 10% and 40% for validation. The sample size shall be at least ten (10), unless fewer than ten (10) indications are reported within that range, in which case Sable would examine the number of indications called.
50. When sizing metal loss indications, apply interaction/clustering criteria of 6t by 6t for applicable ILI tool(s).

[16] The coating procedure must be submitted to the OSFM prior to the prior to the effective date of the state waiver.

51. Sable must send all field measurements to the ILI tool vendor within 90 days of completing direct examinations and require the ILI vendor to validate the accuracy of the tool. Sable must conduct annual meetings with the ILI tool vendor to discuss tool performance and incorporate lessons learned.
52. Sable must utilize a third-party expert to review all ILI reports, verification of digs, data integration, ILI tool tolerances, development of unity plots, measured field findings, failure pressure ratios and any other finding that could affect the integrity of the pipeline. The review must be conducted within six (6) months of each ILI assessment. The third-party expert must be approved by the OSFM prior to being selected.
53. Within one (1) year from date of issuance, Sable must use a NACE-certified expert to conduct an evaluation and determine if alternating current (AC) interference or direct current (DC) interference or shorting that could contribute to external corrosion is occurring. The expert must recommend the frequency of subsequent interference surveys. All evaluations must be approved and signed by the NACE-certified expert.

Data Requirements for Predicted Failure Analysis

54. Unless the defect dimensions have been verified using a direct examination measurements, Sable must explicitly analyze uncertainties in reported assessment results including but not limited to tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly, interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance, in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses.
55. The analyses performed in accordance with this state waiver must utilize pipe and material properties of the pipe body and longitudinal weld seam that are documented in *traceable, verifiable, and complete* records.

Recordkeeping

56. Procedures, records of investigations, data, analyses, and other actions made in accordance with the requirements of this state waiver shall be kept for the life of the pipeline and must be submitted to the OSFM, in the manner requested (electronic, hardcopy, or other format) within 30 days.
57. Sable must maintain the following records:
    a. Technical approach used for the analysis
    b. All data used and analyzed
    c. Pipe and longitudinal weld seam properties
    d. Procedures used to implement state waiver conditions

e. Evaluation methodology used
f. Models used
g. Direct in situ examination data
h. All in-line inspection tool assessments information evaluated
i. Pressure test data and results
j. All in-the-ditch assessments performed on the pipeline segments
k. All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operations results
l. All finite element analysis results
m. The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting methodology
n. The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods
o. Safety factors used for fatigue life and/or predicted failure pressure calculations
p. Reassessment time interval and safety factors
q. The date of the review
r. Confirmation of the results by qualified technical subject matter expert(s)
s. Approval by responsible Sable management personnel
t. Records of additional preventive and mitigative (P&M) measures performed
u. Reports required by this State Waiver.

Reporting

58. Any release on the pipeline shall be reported to the OSFM at the earliest practicable moment following discovery but no later than 24 hours from the time of discovery via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Accident Notification*.[17]
59. An email notification shall be made at least three (3) days prior to the pipeline being exposed for non-emergency purposes of field evaluation and repair via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Pipeline Repair CA-324*. The email notification shall include, if applicable:
    a. Tool type and run date
    b. Unique identifier (e.g. Dig Number, Joint Number, Flaw ID, Condition Type)
    c. Dig sheets
    d. Field contact information for Sable
    e. Time and location of the field evaluation and repair.
60. Sable shall provide a Summary of Conditions Report within 210 days of the last date of an ILI run via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Summary of Conditions CA-324* and include:

[17] This requirement does not relieve Sable from spill reporting requirements that might exist under local, state or federal regulations.

   a. Tool type
   b. Run date
   c. Summary of Conditions Report[18]
   d. Final Vendor Report and Pipe Tally

61. Sable shall provide a report to the OSFM by June 15th of every year for the duration of the state waiver. The report shall be addressed to the OSFM Assistant Deputy Director, Chief of Pipeline Safety via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Annual Report CA-324*. At a minimum, the annual report shall contain the following, if applicable:
   a. A Closure Report for the previous calendar (CY) which contains:
      i. Features that were remediated in previous CY
         1. Provide documentation for the in-the-ditch assessments and repairs
      ii. Identify features that remain to be assessed
      iii. Unity Plots for previous ILI runs
   b. Fracture mechanics and pressure cycling analyses in accordance with Condition 48
   c. The third-party ILI expert reviews in accordance with Condition 52
   d. AC and DC Interference surveys that are due in accordance with Condition 53
   e. A copy of the CGRA for prior year including:
      i. Mean corrosion growth rate for the pipeline
      ii. Distribution graph of the corrosion growth rate for the pipeline (e.g. occurrences (#) vs. corrosion rate (mpy)

Limitations

62. This state waiver is limited to a term of no more than (10) years from the date of issuance. If Sable elects to seek renewal of this state waiver, it must submit a renewal request to the OSFM at least 180 days prior to the expiration date, including a justification for continuation of the waiver.
63. Should Sable fail to comply with any conditions of this state waiver or should the OSFM determine that this state waiver is no longer appropriate or is inconsistent with pipeline safety, the OSFM may revoke the state waiver and require Sable to comply with all appropriate regulatory requirements.
64. The OSFM may order the pipeline shutdown at any time.
65. The OSFM may issue a compliance order or may initiate proceedings to determine the nature and extent of the violations and appropriate civil penalty for

[18] The OSFM may stipulate specific formatting or other information (e.g. Condition Type, Anomaly Details, Remaining Strength Calculation Method, Failure Pressure, CGRA, etc.) to be included in the Summary of Conditions Reports, Closure Report and Annual Reports if information provided is not deemed sufficient.

failure to comply with this state waiver. The terms and conditions of any compliance order shall take precedence over the terms of the state waiver.

66. In the event of conflict between the state waiver conditions and industry standards, the state waiver conditions shall prevail.
67. If Sable sells, merges, transfers or otherwise disposes of all or part of the assets covered by the state waiver, Sable must provide the OSFM written notice of the change within 30 days of the consummation date. In the event of such transfer, the OSFM reserves the right to revoke, suspend, or modify the state waiver.

Should you have any questions, please contact Alin Podoreanu, Supervising Pipeline Safety Engineer at (916) 212-8891.

Sincerely,

DocuSigned by:
James Hosler
980F8D3AE95C42E...

JAMES HOSLER
Assistant Deputy Director
Chief of Pipeline Safety and CUPA Programs

Enclosure(s): (1) Pacific Pipeline Company State Waiver Application for CA-324

cc: Doug Allen, Supervising Pipeline Safety Engineer, OSFM
Andy Chau, Supervising Pipeline Safety Engineer, OSFM
Brendan Feery, Supervising Pipeline Safety Engineer, OSFM
Huy Nguyen, Supervising Pipeline Safety Engineer, OSFM
Alin Podoreanu, Supervising Pipeline Safety Engineer, OSFM
Tuan Tran, Pipeline Safety Engineer, OSFM
Josh Cleaver, Staff Counsel, CAL FIRE
Max Kieba, Engineering and Research Division, PHMSA
Joshua Johnson, Engineering and Research Division, PHMSA

EXHIBIT G

DEPARTMENT OF FORESTRY AND FIRE PROTECTION
OFFICE OF THE STATE FIRE MARSHAL
P.O. Box 944246
Sacramento, California 94244-2460
(916) 568-3800
Website: www.fire.ca.gov

CERTIFIED MAIL No: 9589-0710-5270-1475-5353-15

December 17, 2024

Lance Yearwood
Vice President
Sable Offshore Corp
845 Texas Avenue, Suite 2920
Houston, Texas 77002

SUBJECT: LETTER OF DECISION ON THE STATE WAIVER REQUEST FOR LIMITED EFECTIVENESS OF CATHODIC PROTECTION ON THERMALLY INSULATED PIPELINE AND CORROSION OF OR ALONG A LONGITUDINAL SEAM WELD (CA-325A/B)

Operator: Sable Offshore Corp
OPID# 40851
845 Texas Avenue, Suite 2920
Houston, Texas 77002

Pipeline: OSFM Line ID 0001 - 113.56 miles (Gaviota to Sisquoc to Pentland) of Sable Offshore Corp CA-325A/B (OSFM Line ID 0001) located in Santa Barbara County, San Luis Obispo County, and Kern County, California as described in the request of state waiver dated April 24, 2024

Dear Mr. Yearwood:

The Office of the State Fire Marshal (OSFM) received Sable Offshore Corp's (*Sable*) state waiver request (*Application*) on April 24, 2024, in accordance with the terms of the Consent Decree (CD) between Plains Pipeline, L.P. and the United States of America and the People of the State of California, DOJ Case REF. NO. 90-5-1-1-1130 (Appendix B, Article 1.1.D).

In addition, Sable requested a regulatory relief from Title 49 Code of Federal Regulations (49 C.F.R.), § 195.452(h)(4)(iii)(H) *Corrosion of or along a longitudinal seam weld* for Sable CA-325 A/B.

Sable explained that its goal is to appropriately manage the risk of corrosion under insulation that may occur as a result of inadequate cathodic protection due to the shielding effects of the polyurethane foam and the polyethylene tape wrap. Sable described the measures it has taken to address this risk and implemented and proposed a number of additional measures designed to mitigate the risk of corrosion under insulation that may result from potential ineffective cathodic protection (CP).

Sable provided the OSFM with its proposed measures to mitigate the risk of corrosion under insulation. Sable also provided the OSFM information from the completed in-line inspections and additional data requested by our office. The OSFM Pipeline Safety Engineers have reviewed the materials provided and have been in communication with the United States Department of Transportation (USDOT), Pipeline and Hazardous Materials Safety Administration (PHMSA) Engineering and Research Division to incorporate PHMSA's recommended conditions into the state waiver.

The OSFM has regulatory jurisdiction over the safety standards and practices of intrastate hazardous liquid pipeline transportation within California. As a Pipeline Safety Program that is certified under 49 USC § 60105, the OSFM may grant a state waiver with a pipeline safety regulation adopted by the state of California. Title 49 C.F.R., Part 195 was adopted by reference as it relates to hazardous liquid pipelines within Title 19 California Code of Regulations (19 CCR), Section 2000.

This state waiver applies to Sable's Line CA-325A/B (OSFM Line ID 0001) which consists of a 113.56 mile long, 30-inch outside diameter pipeline segment with the origin and termination points as described in the application. The pipeline is located in Santa Barbara County, San Luis Obispo County, and Kern County, California and shall be referred herein as CA-325A/B. CA-325A/B consists of two shorter pipeline segments, CA-325A and CA-325B. The pipeline segment CA-325A, located completely in Santa Barbara County, starts in Gaviota and ends at Sisquoc. CA-325A is approximately 38.72 miles long. The other pipeline segment, CA-325B, which is directly downstream of CA-325A, begins at Sisquoc and terminates in Pentland. CA-325B is approximately 74.84 miles long and traverses Santa Barbara County, San Luis Obispo County, and Kern County, California. The state waiver shall not become effective until (1) PHMSA issues an Order approving the waiver or stating it has no objection to the waiver or (2) PHMSA takes no action on the waiver within sixty (60) days after receiving the Letter of Decision from the OSFM.

The state waiver is limited to a term of no more than ten (10) years from the date it becomes effective, which shall be considered as the date of issuance. The OSFM may terminate the state waiver under conditions detailed below.

Applicable Regulations

The OSFM hereby grants this state waiver for CA-325 A/B, provided that Sable complies with the specific requirements in this state waiver and any additional conditions outlined by PHMSA. The pipeline must be operated and maintained in accordance with the CD, these state waiver conditions and 49 C.F.R. Part 195, with the exception of 49 C.F.R. §195.452(h)(4)(iii)(H). In event of a conflict between the state waiver conditions and the applicable requirements under 49 C.F.R. Part 195, the state waiver conditions control. Should additional federal or State statutory or regulatory requirements come into effect following the implementation of this state waiver, CA-325 A/B shall be subject to those requirements except where they are in conflict with the State Waiver or the safe operation of the pipeline.

General Conditions

1. The pipeline can only be used to transport crude oil as stated in the application.
2. The maximum operating pressure (MOP) cannot exceed:
   a. 1000 pounds per square inch gauge (psig) for CA-325A.
   b. 1292 psig for CA-325B.
3. The maximum operating temperature of the crude oil must not exceed:
   a. 125 Fahrenheit for more than 12 consecutive hours for CA-325A. Temperature transmitters must be installed on CA-325A at Gaviota station to monitor the temperature of CA-325A/B at this facility.
   b. 110 Fahrenheit for more than 12 consecutive hours for CA-325B. Temperature transmitters must be installed on CA-325A/B at Sisquoc station to monitor the temperature of CA-325A/B at this facility.
4. Prior to startup, Sable must develop and implement procedures for the conditions and requirements described in the state waiver.
5. This state waiver does not relieve Sable from other requirements under 49 C.F.R. Part 195 or the Elder California Pipeline Safety Act of 1981 other than contained herein.
6. This state waiver does not relieve Sable from any requirements imposed by the Consent Decree (United States District Court Central District of California Civil Action No. 2:20-cv-02415).
7. In-line inspection must include:
   a. Use of a tool that is at least capable of reliably detecting and identifying cluster corrosion and general corrosion. Definition of cluster and general corrosion is as follows:
      i. Cluster means two or more adjacent metal loss features in the wall of the pipe or weld that may interact based on interaction criteria.
      ii. General corrosion means uniform or gradually varying loss of wall thickness over an area.
   b. Use of a tool that is at least capable of reliably detecting and sizing corrosion at a 90 percent probability of detection (POD) and probability of identification (POI)
   c. Use of a tool that is at least capable of reliably detecting and sizing crack or crack-like anomalies at a 90 percent POD and POI

8. Prior to placing CA-325A/B in operation, Sable must perform fracture toughness tests on the existing 30" pipe from CA-325A/B in accordance with ASTM E1820-23B Standard Test Method for Measurement of Fracture Toughness. All of the test specimens must be from both of the two following predominant existing 30" pipe specifications:
   a. API 5L X70 pipe with a nominal thickness of 0.281" that was manufactured by the various pipe mills in the 1980s.
   b. API 5L X65 pipe with a nominal thickness of 0.344" that was manufactured by the various pipe mills in the 1980s.

   At least three (3) separate tests must be performed from each pipe mill, for both of the two pipe specifications listed above, to obtain the fracture toughness values of the pipe body, heat affected zone (HAZ)[1], and the DSAW long seam weld on the pipe to represent the fracture toughness of CA-325A/B (i.e. three (3) samples for pipe body, three (3) samples for HAZ, and three (3) samples for the DSAW long seam weld). The lowest fracture toughness value must be applied to conditions 10, 31, 34, and 49. Sable may use pipe samples taken opportunistically during ongoing pipeline maintenance and repair efforts.[2]
9. All immediate and 180-day repair conditions that are listed in this state waiver must be evaluated and remediated prior to restarting CA-325A/B. Sable must utilize Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) tools within seven (7) days of achieving initial steady state operation in accordance with an ILI survey schedule approved by the OSFM. Sable must utilize the most recent Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) results when identifying these repair conditions.
10. Remaining strength of pipe calculation for all metal loss anomalies must be in accordance with the Modified B31G method as described in ASME B31G *Manual for Determining the Remaining Strength of Corroded Pipelines.* If ASME B31G 2012 Edition is used, then it must comply with the conditions in accordance with Section 1.2 and exclusions in accordance with Section 1.3 of ASME B31G 2012 Edition. However, if the metal loss anomaly intersects or is within one (1) inch (circumferentially) of the longitudinal seam weld, Sable must also calculate the predicted failure pressure of the anomaly by using the crack-like flaw evaluation method ASME FFS-1/API 579-1.
11. Sable must utilize cleaning pigs at regular intervals not to exceed a biweekly basis to maintain adequate cleanliness on the internal pipe wall of its CA-325A/B.

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[1] The heat affected zone (HAZ), as used in the state waiver, is defined as a 1-inch-wide area on either side of the longitudinal weld seam.
[2] Sable must submit all fracture toughness results to the OSFM prior to restarting the pipeline.

Pressure Testing

12. Prior to placing the pipeline in operation, Sable must conduct a spike hydrostatic pressure test of the state waiver pipeline segment *CA-325A* at a minimum pressure that is at least 1.39 times the MOP, for a minimum of 15 minutes after the spike test pressure is stabilized. Sable must ensure that the spike hydrostatic pressure at the highest elevation of each testable segment is at least 1.39 times the MOP. Sable must field evaluate and remediate the following anomalies before performing the spike hydrostatic test on CA-325A:
    - **a.** All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.
    - **b.** All anomalies that have a predicted failure pressure less than or equal to 1.5 times MOP.
13. Immediately following the spike hydrostatic pressure test, Sable must conduct an 8-hour hydrostatic pressure test of the state waiver pipeline segment *CA-325A* at a minimum of 1.25 times the MOP.
14. Prior to placing the pipeline in operation, Sable must conduct a hydrostatic pressure test of the state waiver pipeline segment *CA-325B* at a minimum pressure of 1.25 times the MOP, for a minimum of 8 hours. Sable must ensure that the hydrostatic pressure at the highest elevation of each testable segment is at least 1.25 times the MOP. Sable must field evaluate and remediate the following anomalies before performing the hydrostatic test on CA-325B:
    - a. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.
    - b. All anomalies that have a predicted failure pressure less than or equal to 1.4 times MOP.
15. Sable must obtain the Test ID from the OSFM for each hydrostatic pressure test segment and have the approved independent testing firm forward the certified test results to the OSFM.
16. Each hydrostatic pressure test must be performed in accordance with the applicable requirements of 49 C.F.R., Part 195 E – Pressure Testing and monitored by an independent testing firm listed under the OSFM approved hydrostatic testing companies.
17. Failures resulting from the spike hydrostatic pressure test or the 8-hour strength test shall be immediately reported[3] to the OSFM via email at PipelineNotification@fire.ca.gov
    Subject: OSFM State Waiver - Hydrotest Failure.
18. Section(s) of the state waiver pipeline segments that failed during the required hydrotesting must be repaired by removing and replacing the failed section. The OSFM reserves the right to revoke the state waiver if failure(s) raise the concern that the pipeline cannot be safely operated.

[3] In addition to the OSFM reporting, Sable shall follow all additional state reporting requirements.

In-Line Inspection (ILI) Assessment and Frequency

19. At least 90 days prior to performing in-line inspections of the state waiver segment, Sable shall provide the OSFM with a written notification to PipelineNotification@fire.ca.gov describing its assessment plan with the following information:
    a) Dates for integrity assessment
    b) In-line inspection tool(s) selected, in accordance with API Standard 1163 Section 5 and NACE SP0102[4] to assess the integrity of the subject pipe segment(s) in which ILIs must be capable to detect and size wall loss, dents, internal corrosion, external corrosion, cracks and crack-like indications
    c) In-line inspection tool vendor(s)
    d) Required tool specifications including operational specifications and anomaly sizing tolerances
    e) Tool validation methodology
    f) Anomaly feature identification criteria and reporting thresholds – wall loss, dents, internal corrosion, external corrosion, cracks, and crack-like indications
    g) Criteria used to identify locations for excavation and field verification
    h) Non-destructive examination
20. Within seven (7) days prior to any anticipated ILI tool run, Sable must utilize extensive brush pigs and solvents (xylene or other chemicals) to ensure that the internal pipe wall does not have any corrosive products, wax, and bacteria buildup that may affect the ILI tool performance.
21. Metal Loss Tool(s)
    a. Initial ILI tool runs – Each year, during the first two (2) years of operating CA-325 A/B, Sable shall conduct at least two (2) ILIs using a UTWM tool with an inertial measurement unit (IMU). Sable shall compare both runs and evaluate all available information, including these tool runs and corresponding IMU data. Sable shall perform the UTWM tool run every six (6) months not to exceed nine (9) months. If a UTWM tool run is unsuccessful, Sable shall identify the limitations that prevented the UTWM tool run from being successful, consider changes to increase the likelihood of a successful UTWM tool run, and use best efforts to rerun the UTWM tool within 30 days.
    b. Subsequent ILI tool runs – After the first two (2) years of operating CA-325 A/B, Sable shall conduct at least one (1) Ultrasonic Wall Measurement tool (UTWM) each calendar year, not to exceed 15 months or the ILI assessment must be assessed at more frequent intervals if the remaining Failure Pressure Ratio will be less than 1.39 times MOP prior to the next ILI assessment, based upon anomaly growth estimates and pressure cycling. If,

[4] Industry standards that are referenced in this state waiver must utilize the editions that are incorporated by referenced in Title 49 Part 195.3 unless another edition was explicitly specified.

any UTWM tool run is deemed to be unsuccessful, Sable shall document the reasons why the UTWM tool was unsuccessful, consider changes to increase the likelihood of a successful UTWM tool run, and must reassess the pipeline within 30 days after it was deemed to be unsuccessful. All metal loss tool runs must also utilize an Inertial Measurement Unit (IMU).

22. Crack Detection Tools - Sable must run at least one (1) Ultrasonic Shear Wave Crack Detection (USCD) tool each calendar year, not to exceed 15 months[5] or the ILI assessment must be assessed at more frequent intervals if Condition 49 determined a shorter assessment interval.
    a. These crack tool runs must utilize an Inertial Measurement Unit (IMU) and must be able to detect and size axial and circumferential cracks.
    b. USCD Performance Specification Requirements
        i. The USCD tools must have a probability of detection that is ≥ 90% for axial and circumferential cracks.
        ii. The minimum crack depth that can be detected must be at least 1 mm for axial and circumferential cracks that are located in the base material.
        iii. The minimum crack depth that can be detected must be at least 2 mm for axial and circumferential cracks that are located in the weld.
        iv. The depth sizing accuracy for cracks must be ± 0.8 mm for axial cracks and ± 1 mm for circumferential cracks.
23. Dents and Pipe Deformation: Sable shall conduct a high-resolution deformation ILI tool with each UTWM.
24. Where any ILI tool fails to record data for 5% or more of the external and/or internal surface area of the inspected segment, reassess with the ILI tool to cover the area that is deemed to be inadequate data of the inspected segment. In addition, if the ILI tool travels at a speed that is outside the range of the tool velocity listed in the tool specification for 2% or more of the length of the inspected segment, Sable must rerun the ILI tool to reassess the pipeline segment in which the ILI tool velocity was outside of the specified tool velocity range.
25. All ILI tool runs must obtain the Test ID from the OSFM prior to run.
26. Sable must require its ILI tool vendor(s) to include in the vendor's inspection report all metal loss indications of 10% or greater, based on raw data, prior to adding in any correction for tool tolerance.
27. Sable must incorporate ILI tool accuracy by ensuring that each ILI tool service provider determines the tolerance of each tool, in accordance with API Standard 1163 Second Edition and includes that tolerance in determining the size of each indication reported to Sable.

[5] Sable may petition the OSFM to revise the reassessment interval for Crack Detection Tool(s) when sufficient evidence is available to determine if crack growth rates could support a longer reassessment interval. Changes to the reassessment interval are subject to the OSFM and PHMSA approval.

28. Sable must account for ILI tool tolerance and anomaly growth rates in scheduled response times, repairs, and future reassessment intervals. Sable must document and justify the values used. Sable must demonstrate ILI tool tolerance accuracy for each ILI tool run by using calibration, excavations, and unity plots[6] that demonstrate ILI tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). Sable must compare previous indications to current indications that are significantly different. If a trend is identified where the tool has been consistently over-calling or under-calling, the remaining ILI features must be re-graded accordingly.
29. Prior to the ILI final report being received, Sable must perform at least four (4) separate validation digs that do not interact with each other. At a minimum, Sable must perform validation digs in accordance with Level 2 of API Standard 1163, "In-line Inspection System Qualification" (Second Edition, April 2013).

<u>Discovery of Condition</u>

30. The discovery date must be within 180 days of any ILI tool run for each type of ILI tool.

<u>Immediate Repair Conditions</u>[7]

31. A crack or crack-like anomaly that meets any of the following criteria:
    a. Crack or crack-like anomaly that is equal to or greater than 50% of pipe wall thickness.
    b. Crack or crack-like anomaly that has predicted failure pressure of less than 1.39 times the MOP as calculated using crack-like flaw evaluation method ASME FFS-1/API 579-1.
32. Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.39 times the MOP.
33. Any external cluster corrosion or external general corrosion that is located on the bottom half of the pipeline (below the 3 and 9 o'clock positions) where the remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.[8]

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[6] A minimum of four (4) independent direct examination excavations must be used for unity plots.

[7] The criteria outlined in the state waiver is supplemental to the requirements set forth in *§195.452(h)(4)(i) Immediate repair conditions* and does not relieve Sable from complying with §195.452(h)(4)(i). All immediate repair conditions must be remediated with a permanent repair method.

[8] Cluster means two or more adjacent metal loss features in the wall of the pipe or weld that may interact based on interaction criteria. General corrosion means uniform or gradually varying loss of wall thickness over an area.

180-Day Repair Conditions[9]

34. A crack or crack-like anomaly that has predicted failure pressure of less than 1.5 times the MOP.
35. Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.
36. All internal or external metal loss anomalies that have an ILI reported depth of 40% or greater wall loss, including tool sizing tolerance for depth.[10]
37. For any crack (likely crack or possible crack) or crack-like anomaly, regardless of its dimensions, that interacts with metal loss anomalies and are within one (1) inch (circumferentially) of the longitudinal seam weld, Sable must integrate the ILI results from the most recent crack tool run and the most recent metal loss tool run before the discovery date deadline.

Corrosion Growth Rate Analysis (CGRA)

38. Sable must develop a CGRA procedure to annually calculate corrosion growth rates between successive ILI's (using most recent ILI compared to prior ILI) and perform pipeline remediations needed to assure the integrity of the pipeline is maintained.[11] The timing of pipeline remediations under this condition shall be based on the most recent calculation of short-term corrosion rates.
39. The CGRA procedure must include ILI data matching methods[12] to analyze data from successive ILI's, methodologies for growth rate calculations and errors from comparing ILI data.
40. Sable must identify the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss.
41. When determining the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss, Sable must account for reported ILI depth, tool tolerance and corrosion growth rates[13].

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[9] The criteria outlined in the state waiver is supplemental to the requirements set forth in *§195.452(h)(4)(iii) 180-day conditions* and does not relieve Sable from complying with §195.452(h)(4)(iii). All 180-day repair conditions must be remediated with a permanent repair method.
[10] For example, if the ILI tool reports a 31% metal loss anomaly and the tool sizing tolerance is ±10 for depth, then this anomaly is a 180-day repair condition since it can be considered as an external metal loss anomaly with 41% metal loss depth. If Sable is unable to remediate such indications within 180 days of discovery, Sable must notify OSFM, temporarily reduce the operating pressure, and take further remedial action in accordance with 49 C.F.R. §195.452 until the indication is remediated or until otherwise authorized by the OSFM.
[11] At a minimum, Sable must include signal matching between ILI data sets.
[12] If there are several matching techniques that can be used, Sable must utilize the most accurate method of comparing ILI data sets.
[13] Growth projections must use corrosion rates determined in accordance with the CGRA procedure. A default corrosion rate of 32 mpy must be used in determining projections, if corrosion rates determined by CGRA are less than the default value.

42. All metal loss indications that are projected to reach a depth of 70% or greater wall loss prior to the next ILI, will become actionable and must be remediated before the next ILI.

Pressure Reduction

43. If Sable is unable to perform field evaluation and remediation of any required conditions within the time limit conditions specified in the state waiver, Sable must temporarily implement a minimum 20 percent or greater operating pressure reduction, based on actual operating pressure for two (2) months prior to the date of inspection, until the anomaly is repaired.

In Field Direct Examination of Pipe

44. Direct examinations[14] of pipe must include appropriate non-destructive examination methods for cracking such as magnetic particle inspection (MPI), shear wave technology or phased array ultrasonic testing (PAUT).[15] PAUT must be used for sizing any crack or crack-like anomaly lengths and depths.
45. Permanent repairs of metal loss anomalies are required for any section of pipe with wall loss equal to or greater than 40% in accordance with repair method 1, 4b, or 5 of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition. However, the following additional conditions are applied if Sable chooses repair method 5 for metal loss anomalies:
    a. Method 5 must not be used on metal loss anomalies that are in the HAZ, girth weld, or longitudinal seam weld.
    b. Sable must increase the metal loss anomaly's depth by 20% when they input it into the formula for calculating the number of wraps needed for repair method 5.
    c. After the anomaly is repaired via repair method 5, Sable must monitor the anomaly's wall loss depth in subsequent UTWM tool runs. If the anomaly's wall loss depth increases by more than 15% of the wall thickness in the subsequent UTWM tool runs, Sable must repair this anomaly via repair method 1 or 4b of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition.
46. Permanent repairs are required for all cracks and/or crack-like anomalies discovered during direct examination, regardless of crack depth or crack length in accordance with repair method 1 or 4b of Table 451.6.2(b)-1 of ASME B31.4 2006 Edition.

[14] Any time the pipeline is exposed for direct examination of an indication or to perform a repair, Sable must document the condition of the coating and carrier pipe (including anomalies) with photographs.
[15] Direct examinations for ILI reported crack or crack-like indications must include a magnetic particle inspection complimented by shear wave technology or inspection by phased array ultrasonic testing.

47. Sable must develop a coating repair procedure for excavated or remediated corrosion anomalies that prevents further external corrosion and seals transition areas from currently insulated pipe to newly coated sections. Any time a shrink sleeve or coating is exposed, remove the shrink sleeve and coating, investigate circumferentially and longitudinally along the pipe for external corrosion and coating deterioration, and recoat with two-part epoxy. Sable must recoat in accordance with their coating repair procedure.[16]
48. All external polyurethane foam and the polyethylene tape wrap on buried pipe that are exposed during the field evaluation must not be replaced with new insulation or polyethylene tape wrap.

Integrity Management

49. A fracture mechanics and pressure cycling evaluation is required for un-remediated cracks and crack-like indications detected by ILI or indirect inspection tools.
    a. Sable must determine the predicted failure pressure, failure stress pressure and crack growth of un-remediated cracks and crack-like anomalies in accordance with 49 C.F.R. §192.712(d)(1).
    b. Sable must perform a fatigue analysis using an applicable fatigue crack growth law or other technically appropriate engineering methodology in accordance with 49 C.F.R. §192.712(d)(2).
50. Sable must analyze a sample of additional indications of varying amounts of metal loss between 10% and 40% for validation. The sample size shall be at least ten (10), unless fewer than ten (10) indications are reported within that range, in which case Sable would examine the number of indications called.
51. When sizing metal loss indications, apply interaction/clustering criteria of 6t by 6t for applicable ILI tool(s).
52. Sable must send all field measurements to the ILI tool vendor within 90 days of completing direct examinations and require the ILI vendor to validate the accuracy of the tool. Sable must conduct annual meetings with the ILI tool vendor to discuss tool performance and incorporate lessons learned.
53. Sable must utilize a third-party expert to review all ILI reports, verification of digs, data integration, ILI tool tolerances, development of unity plots, measured field findings, failure pressure ratios and any other finding that could affect the integrity of the pipeline. The review must be conducted within six (6) months of each ILI assessment. The third-party expert must be approved by the OSFM prior to being selected.
54. Within one (1) year from date of issuance, Sable must use a NACE-certified expert to conduct an evaluation and determine if alternating current (AC)

[16] The coating procedure must be submitted to the OSFM prior to the prior to the effective date of the state waiver.

interference or direct current (DC) interference or shorting that could contribute to external corrosion is occurring. The expert must recommend the frequency of subsequent interference surveys. All evaluations must be approved and signed by the NACE-certified expert.

<u>Data Requirements for Predicted Failure Analysis</u>

55. Unless the defect dimensions have been verified using a direct examination measurements, Sable must explicitly analyze uncertainties in reported assessment results including but not limited to tool tolerance, detection threshold, probability of detection, probability of identification, sizing accuracy, conservative anomaly, interaction criteria, location accuracy, anomaly findings, and unity chart plots or equivalent for determining uncertainties and verifying tool performance, in identifying and characterizing the type and dimensions of anomalies or defects used in the analyses.
56. The analyses performed in accordance with this state waiver must utilize pipe and material properties of the pipe body and longitudinal weld seam that are documented in *traceable, verifiable, and complete* records.

<u>Recordkeeping</u>

57. Procedures, records of investigations, data, analyses, and other actions made in accordance with the requirements of this state waiver shall be kept for the life of the pipeline and must be submitted to the OSFM, in the manner requested (electronic, hardcopy, or other format) within 30 days.
58. Sable must maintain the following records:
    a. Technical approach used for the analysis
    b. All data used and analyzed
    c. Pipe and longitudinal weld seam properties
    d. Procedures used to implement state waiver conditions
    e. Evaluation methodology used
    f. Models used
    g. Direct in situ examination data
    h. All in-line inspection tool assessments information evaluated
    i. Pressure test data and results
    j. All in-the-ditch assessments performed on the pipeline segments
    k. All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operations results
    l. All finite element analysis results
    m. The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting methodology

n. The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods
o. Safety factors used for fatigue life and/or predicted failure pressure calculations
p. Reassessment time interval and safety factors
q. The date of the review
r. Confirmation of the results by qualified technical subject matter expert(s)
s. Approval by responsible Sable management personnel
t. Records of additional preventive and mitigative (P&M) measures performed
u. Reports required by this State Waiver.

Reporting

59. Any release on the pipeline shall be reported to the OSFM at the earliest practicable moment following discovery but no later than 24 hours from the time of discovery via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Accident Notification*.[17]
60. An email notification shall be made at least three (3) days prior to the pipeline being exposed for non-emergency purposes of field evaluation and repair via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Pipeline Repair CA-325 A/B*. The email notification shall include, if applicable:
    d. Tool type and run date
    e. Unique identifier (e.g. Dig Number, Joint Number, Flaw ID, Condition Type)
    f. Dig sheets
    g. Field contact information for Sable
    h. Time and location of the field evaluation and repair.
61. Sable shall provide a Summary of Conditions Report within 210 days of the last date of an ILI run via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Summary of Conditions CA-325 A/B* and include:
    i. Tool type
    j. Run date
    k. Summary of Conditions Report[18]
    l. Final Vendor Report and Pipe Tally
62. Sable shall provide a report to the OSFM by June 15th of every year for the duration of the state waiver. The report shall be addressed to the OSFM Assistant Deputy Director, Chief of Pipeline Safety via email at PipelineNotification@fire.ca.gov, *Subject: OSFM State Waiver – Annual Report*

[17] This requirement does not relieve Sable from spill reporting requirements that might exist under local, state or federal regulations.
[18] The OSFM may stipulate specific formatting or other information (e.g. Condition Type, Anomaly Details, Remaining Strength Calculation Method, Failure Pressure, CGRA, etc.) to be included in the Summary of Conditions Reports, Closure Report and Annual Reports if information provided is not deemed sufficient.

CA-325 A/B. At a minimum, the annual report shall contain the following, if applicable:

a. A Closure Report for the previous calendar (CY) which contains:
    i. Features that were remediated in previous CY
        1. Provide documentation for the in-the-ditch assessments and repairs
    ii. Identify features that remain to be assessed
    iii. Unity Plots for previous ILI runs
b. Fracture mechanics and pressure cycling analyses in accordance with Condition 49
c. The third-party ILI expert reviews in accordance with Condition 53
d. AC and DC Interference surveys that are due in accordance with Condition 54
e. A copy of the CGRA for prior year including:
    i. Mean corrosion growth rate for the pipeline
    ii. Distribution graph of the corrosion growth rate for the pipeline (e.g. occurrences (#) vs. corrosion rate (mpy)

Limitations

63. This state waiver is limited to a term of no more than ten (10) years from the date of issuance. If Sable elects to seek renewal of this state waiver, it must submit a renewal request to the OSFM at least 180 days prior to the expiration date, including a justification for continuation of the waiver.
64. Should Sable fail to comply with any conditions of this state waiver or should the OSFM determine that this state waiver is no longer appropriate or is inconsistent with pipeline safety, the OSFM may revoke the state waiver and require Sable to comply with all appropriate regulatory requirements.
65. The OSFM may order the pipeline shutdown at any time.
66. The OSFM may issue a compliance order or may initiate proceedings to determine the nature and extent of the violations and appropriate civil penalty for failure to comply with this state waiver. The terms and conditions of any compliance order shall take precedence over the terms of the state waiver.
67. In the event of conflict between the state waiver conditions and industry standards, the state waiver conditions shall prevail.
68. If Sable sells, merges, transfers or otherwise disposes of all or part of the assets covered by the state waiver, Sable must provide the OSFM written notice of the change within 30 days of the consummation date. In the event of such transfer, the OSFM reserves the right to revoke, suspend, or modify the state waiver.

Should you have any questions, please contact Alin Podoreanu, Supervising Pipeline Safety Engineer at (916) 212-8891.

Sincerely,

DocuSigned by:
James Hosler
980F8D3AE95C42E...

JAMES HOSLER
Assistant Deputy Director
Chief of Pipeline a Safety and CUPA Programs

Enclosure(s): (1) Pacific Pipeline Company State Waiver Application for CA-325 A/B

cc: Doug Allen, Supervising Pipeline Safety Engineer, OSFM
Andy Chau, Supervising Pipeline Safety Engineer, OSFM
Brendan Feery, Supervising Pipeline Safety Engineer, OSFM
Huy Nguyen, Supervising Pipeline Safety Engineer, OSFM
Alin Podoreanu, Supervising Pipeline Safety Engineer, OSFM
Tuan Tran, Pipeline Safety Engineer, OSFM
Josh Cleaver, Staff Counsel, CAL FIRE
Max Kieba, Engineering and Research Division, PHMSA
Joshua Johnson, Engineering and Research Division, PHMSA

EXHIBIT H

Accufacts Inc.

"Clear Knowledge in the Over Information Age"

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

Prepared For

The Center for Biological Diversity
&
The Environmental Defense Center

February 21, 2025

Table of Contents

I. Summary.

Accufacts Inc. ("Accufacts") was asked to provide my expert opinion on the Letters of Decision on the State Waivers for the startup of Line CA-324, CA-325A, and CA-325B ("Pipelines") made public in mid-January 2025 by the Office of the State Fire Marshal ("OSFM").[1] This report builds on a previous Accufacts report issued on December 20, 2024."[2] By agreement, a Consent Decree gives the OSFM main pipeline safety approval authority of the Pipelines if the OSFM's actions are not in conflict with PHMSA pipeline safety regulations, and if PHMSA decides the proposed state waiver alternative measures "provide an equal or greater level of safety."[3] It is my understainding that PHMSA can choose to: 1) Not comment on this matter allowing the State Waiver to occur and startup to proceed, 2) Not approve the waiver preventing the startup, or 3) Impose additional requirements to assure an equal or greater level of safety to current minimum federal pipeline safety regulations occurs.

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

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

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

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

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

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

[5] 49CFR452(h)(4)(iii)(H).

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

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

II. The current installation renders the CP system ineffective.

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

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

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[6] Plains Administrative Draft EIR, "Plains Replacement Pipeline Project," February 2022.

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

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

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

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

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

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

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

[9] Accufacts, “Evaluation of Las Flores Pipeline System Startup Proposal,” prepared for The Center for Biological Diversity & The Environmental Defense Center, December 20, 2024, p. 13.
[10] OS OSFM letter to Sable/PPC Offshore Corp, “Decision Letter 324 and Decision Letter 325A/B”),” dated 12/17/24, pp. 11 and 11 respectively.

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

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

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

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

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

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

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

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

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

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

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

VI. Types of ILI technology.

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

1. **General wall loss corrosion.**

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

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

2. Cracking corrosion.

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

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

VII. What is the purpose of hydrotesting?

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

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

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

[11] Decision Letter 325A/B, "Pressure Testing," page 5.

hydrotest or spike hydrotest on Line 325B. The proposed segments for hydrotests on 325A need to be identified by approximate milepost to permit evaluation as to whether the waiver requirements are appropriate. The reasons for hydrotesting exclusion on Line 325B need to be properly justified and made public by the OSFM.

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

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

IX. Major state waiver deficiencies:

Key observation on the state waivers for the Pipelines:

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

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

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

2. **A major state waiver deficiency for Line 324.**

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

A critical condition in the OSFM Decision letter 324 is:

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

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

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

[12] Decision Letter 324, "Pressure Testing," pages 4 – 5.

3. **Major state waiver deficiencies for Line 325A/B.**

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

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

X. Conclusions.

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

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

Richard B. Kuprewicz
President
Accufacts Inc.

Richard B Kuprewicz

[13] Sable/PPC letter to OSFM, "Subject Pacific Pipeline Company (OPID 40475) State Waiver Application for the Las Flores Pipeline CA-324 (OSFM #00115). Pipeline System Background Data Attachment B of State Application Table B-3 Line Pipe Specifications," July 2023, p. 4.
[14] *Ibid*., "Table B-6 Historic Hydrotest Summary," p. 6.

EXHIBIT I

environmental
DEFENSE CENTER

April 11, 2025

Via U.S. Mail

Office of the State Fire Marshal,
California Department of Forestry and Fire Protection
PO Box 944246
Sacramento, CA 94244-2460
Attn: Daniel Berlant, State Fire Marshal

Re: Notice of Intent to File CEQA Petition

To Department of Forestry and Fire Protection:

PLEASE TAKE NOTICE, under Public Resources Code §21167.5, that Petitioners and Plaintiffs Environmental Defense Center, Get Oil Out!, Santa Barbara County Action Network, Sierra Club, and Santa Barbara Channelkeeper (collectively, "Petitioners"), intend to file a petition and complaint under the provisions of the California Environmental Quality Act (CEQA) against Respondents and Defendants California Department of Forestry and Fire Protection (CalFIRE), by and through its component agency Office of the State Fire Marshal (OSFM), and State Fire Marshal Daniel Berlant (collectively, "Respondents"), challenging Respondents' approval of State Waivers for pipelines CA-324 and CA-325, the two segments of the Las Flores Pipeline System.

The petition and complaint is brought upon the following grounds: Respondents (1) failed to comply with CEQA's environmental review process, (2) failed to comply with mandatory procedures outlined in state and federal pipeline safety laws, and (3) prejudicially abused their discretion in issuing the State Waivers.

The petition and complaint prays for the following relief:

1. That the Court immediately, and on an *ex parte* basis, issue a temporary stay of OSFM's approval of the State Waivers, pending completion of judicial review, pursuant to Code Civ. Proc., § 1094.5(g) and Rule 3.1202(c) of the California Rules of Court;
2. That the Court issue temporary, preliminary, and permanent injunctive relief

906 Garden St. Santa Barbara, CA 93101
PHONE (805) 963-1622
www.EnvironmentalDefenseCenter.org

preventing restart of the Las Flores Pipeline System under the State Waivers;

3. That the Court issue a peremptory writ of mandate directing CalFIRE, by and through OSFM, to set aside and vacate its approval of the State Waiver for CA-324;
4. That the Court issue a peremptory writ of mandate directing CalFIRE, by and through OSFM, to set aside and vacate its approval of the State Waiver for CA-325;
5. That the Court issue a peremptory writ of mandate directing Respondents, should they reconsider Sable's State Waiver applications, to:
   a. prepare a subsequent Environmental Impact Report that considers the potential impacts of operating the Las Flores Pipeline System without effective cathodic protection, without complying with 49 C.F.R. § 195.452(h)(4)(iii)(H), and under the conditions of the proposed State Waivers;
   b. conduct any other procedures that the Court deems necessary and/or appropriate under CEQA;
   c. provide the public with notice and an opportunity for a hearing before granting a State Waiver for either CA-324 or CA-325, as required by federal law;
   d. in granting a State Waiver for either CA-324 or CA-325, provide a statement of reasons, as required by federal law; and
   e. in granting a State Waiver for either CA-324 or CA-325, provide a discussion of factors significant to its decision, as required by state law;
6. That the Court issue the specific additional declaratory relief prayed for in Petitioners' Third and Seventh Causes of Action;
7. That Petitioners be awarded attorneys' fees and costs pursuant to Sections 1021.5 and 1032(b) of the Code of Civil Procedure, and any other applicable law; and
8. For such other and further relief as the Court deems just and proper.

Respectfully submitted,

Linda Krop
Jeremy M. Frankel
Tara C. Rengifo
ENVIRONMENTAL DEFENSE CENTER
Counsel for Petitioners

ATTORNEY OR PARTY WITHOUT ATTORNEY: STATE BAR NO:	FOR COURT USE ONLY
NAME: Linda Krop (No. 118773); Jeremy Frankel (No. 344500); Tara Rengifo (No. 307670) FIRM NAME: Environmental Defense Center STREET ADDRESS: 906 Garden Street CITY: Santa Barbara STATE: CA ZIP CODE: 93101 TELEPHONE NO.: (805) 963-1622 FAX NO. : E-MAIL ADDRESS: lkrop@environmentaldefensecenter.org ATTORNEY FOR (*name*): Petitioners/Plaintiffs Environmental Defense Center et al.	
SUPERIOR COURT OF CALIFORNIA, COUNTY OF Santa Barbara STREET ADDRESS: 1100 Anacapa Street MAILING ADDRESS: P.O. Box 21107 CITY AND ZIP CODE: Santa Barbara, CA 93121 BRANCH NAME: Anacapa Division	
Plaintiff/Petitioner: Environmental Defense Center et al. Defendant/Respondent: Cal. Dep't of Forestry and Fire Protection	CASE NUMBER:
PROOF OF SERVICE—CIVIL **Check method of service *(only one)*:** ☐ By Personal Service ☒ By Mail ☐ By Overnight Delivery ☐ By Messenger Service ☐ By Fax	JUDICIAL OFFICER: DEPARTMENT:

Do not use this form to show service of a summons and complaint or for electronic service. See USE OF THIS FORM on page 3.

1. At the time of service I was over 18 years of age **and not a party to this action**.
2. My residence or business address is:
   906 Garden Street, Santa Barbara, CA 93101
3. ☐ The fax number from which I served the documents is *(complete if service was by fax):*
4. On *(date):* April 11, 2025 I served the following **documents** *(specify):*

   Notifce of Intent to File CEQA Petition

   ☐ The documents are listed in the *Attachment to Proof of Service–Civil (Documents Served)* (form POS-040(D)).
5. I served the documents on the **person or persons** below, as follows:
   a. Name of person served: CalFIRE - Office of the State Fire Marshal
   b. ☒ *(Complete if service was by personal service, mail, overnight delivery, or messenger service.)*
   Business or residential address where person was served:
   PO Box 944246, Sacramento, CA 94244-2460
   c. ☐ *(Complete if service was by fax.)*
   Fax number where person was served:

   ☐ The names, addresses, and other applicable information about persons served is on the *Attachment to Proof of Service—Civil (Persons Served)* (form POS-040(P)).
6. The documents were served by the following means *(specify):*
   a. ☐ **By personal service.** I personally delivered the documents to the persons at the addresses listed in item 5. (1) For a party represented by an attorney, delivery was made (a) to the attorney personally; or (b) by leaving the documents at the attorney's office, in an envelope or package clearly labeled to identify the attorney being served, with a receptionist or an individual in charge of the office; or (c) if there was no person in the office with whom the notice or papers could be left, by leaving them in a conspicuous place in the office between the hours of nine in the morning and five in the evening. (2) For a party, delivery was made to the party or by leaving the documents at the party's residence with some person not younger than 18 years of age between the hours of eight in the morning and eight in the evening.

CASE NAME:	CASE NUMBER:

6. b. [x] **By United States mail.** I enclosed the documents in a sealed envelope or package addressed to the persons at the addresses in item 5 and *(specify one)*:

   (1) [x] deposited the sealed envelope with the United States Postal Service, with the postage fully prepaid.

   (2) [ ] placed the envelope for collection and mailing, following our ordinary business practices. I am readily familiar with this business's practice for collecting and processing correspondence for mailing. On the same day that correspondence is placed for collection and mailing, it is deposited in the ordinary course of business with the United States Postal Service, in a sealed envelope with postage fully prepaid.

   I am a resident or employed in the county where the mailing occurred. The envelope or package was placed in the mail at *(city and state):* Santa Barbara, CA

c. [ ] **By overnight delivery.** I enclosed the documents in an envelope or package provided by an overnight delivery carrier and addressed to the persons at the addresses in item 5. I placed the envelope or package for collection and overnight delivery at an office or a regularly utilized drop box of the overnight delivery carrier.

d. [ ] **By messenger service.** I served the documents by placing them in an envelope or package addressed to the persons at the addresses listed in item 5 and providing them to a professional messenger service for service. *(A declaration by the messenger must accompany this Proof of Service or be contained in the Declaration of Messenger below.)*

e. [ ] **By fax transmission.** Based on an agreement of the parties to accept service by fax transmission, I faxed the documents to the persons at the fax numbers listed in item 5. No error was reported by the fax machine that I used. A copy of the record of the fax transmission, which I printed out, is attached.

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

Date: April 11, 2025

Jeremy Frankel
(TYPE OR PRINT NAME OF DECLARANT)

▶ ______________________
(SIGNATURE OF DECLARANT)

(If item 6d above is checked, the declaration below must be completed or a separate declaration from a messenger must be attached.)

DECLARATION OF MESSENGER

[ ] **By personal service.** I personally delivered the envelope or package received from the declarant above to the persons at the addresses listed in item 5. (1) For a party represented by an attorney, delivery was made (a) to the attorney personally; or (b) by leaving the documents at the attorney's office, in an envelope or package clearly labeled to identify the attorney being served, with a receptionist or an individual in charge of the office; or (c) if there was no person in the office with whom the notice or papers could be left, by leaving them in a conspicuous place in the office between the hours of nine in the morning and five in the evening. (2) For a party, delivery was made to the party or by leaving the documents at the party's residence with some person not younger than 18 years of age between the hours of eight in the morning and eight in the evening.

At the time of service, I was over 18 years of age. I am not a party to the above-referenced legal proceeding.

I served the envelope or package, as stated above, on *(date):*

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

Date: ______________________

____
(NAME OF DECLARANT)

▶ ______________________
(SIGNATURE OF DECLARANT)