January 22, 2026

VIA ELECTRONIC MAIL

Linda Daugherty
Acting Associate Administrator for Pipeline Safety
Pipeline and Hazardous Materials Safety Administration (PHMSA)
US Department of Transportation
1200 New Jersey Avenue, SE
Washington, DC 20590

RE: Application for Special Permit
Sable Offshore Corp.

Dear Ms. Daugherty,

Sable Offshore Corp. (Sable) respectfully submits this Application for Special Permit pursuant to 49 U.S.C. § 60118(c)(1) and 49 C.F.R. § 190.341. As part of this Application, Sable requests that PHMSA issue a Special Permit covering two pipeline segments (Lines CA-324 and CA-325) that together, constitute the Las Flores Pipeline, which is part of an interstate pipeline facility that Sable operates from the Outer Continental Shelf (OCS) off the coast of Santa Barbara, California to Kern County, California, known as the Santa Ynez Pipeline System (SYPS). The Application seeks waiver of certain provisions under 49 C.F.R. Part 195 to implement Appendix B, Article I.1.A and Appendix D, Section 1.b.10 and 1.f of the Consent Decree issued in Civil Action No. 2:20-CV-02415 in the US District Court for the Central District of California (Consent Decree).

Sable shares PHMSA's commitment to pipeline safety and is proposing to comply with substantial alternative measures that provide an equivalent, if not greater, measure of safety as compared to the Part 195 regulation from which it seeks relief. These alternative measures are specifically designed to address the risk of cathodic protection shielding and the attendant external corrosion threats on CA-324 and CA-325 due to degradation of its original coating. These measures include, but are not limited to, significantly increased frequency of In-Line Inspection (ILI) tool runs and more stringent anomaly repair criteria. PHMSA granted Sable an Emergency Special Permit pursuant to 49 C.F.R. § 190.341(g) on December 23, 2025. This application requests substantially the same conditions as provided in the Emergency Special Permit.

In addition, these conditions are substantially the same measures that have already been reviewed and approved by the California Office of the State Fire Marshal (OSFM) through issuance of State Waivers dated December 17, 2024 granting waiver of the same standards for

CA-324 and 325, at a time when these segments were considered part of an intrastate pipeline facility. As part of the State Waiver process, PHMSA evaluated and approved the State Waivers pursuant to its federal oversight obligation in 49 U.S.C. § 60118(d) by issuing letters of no-objection to OSFM on February 11, 2025.[1]

Sable seeks this Special Permit from PHMSA due in part to Sable's November 26, 2025 determination, and PHMSA's December 17, 2025 concurrence that Lines CA-324 and 325 (formerly known as Lines 901 and 903, respectively) are properly classified as pipeline segments that are part of the interstate SYPS pipeline facility. As an interstate pipeline, SYPS is subject to PHMSA's exclusive pipeline safety oversight under 49 U.S.C. § 60104(c). As a result, and for the additional reasons provided in this application, Sable respectfully requests that PHMSA issue a special permit to replace the Emergency Special Permit issued for CA-324 and 325. Sable has patterned this application on its Emergency Special Permit application and the Pacific Pipeline Company's July 10, 2023 applications for state waivers.

Below please find the information specified in 49 C.F.R. § 190.341 in support of this Application:

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

Sable Offshore Corp. PPC (Operator ID #40881)
Attn: Lance Yearwood
845 Texas Avenue
Suite 2920
Houston, TX 77002
(713) 579-8118

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

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

Sable operates the SYPS pipeline facility that encompasses, among other things, a Part 195-regulated emulsion line that transports oil from offshore oil production platforms to the Las Flores Canyon Processing Facility (LFC), LFC, and the Las Flores Pipeline, consisting of Part 195-regulated segments CA-324 and CA-325. A Special Permit is sought specifically for segments CA-324 and CA-325. CA-325 can be further divided into two sub-segments: CA-325A and CA-325B. Table 2-1 summarizes relevant information. A map of the pipeline system is included as ***Attachment A*** and further details about these segments are below:

[1] See Docket Nos. PHMSA-2025-0002 and PHMSA-2025-0003.

Table 2-1: Pipeline Segments Applicable to Special Permit Application

Pipeline Facility Name	Pipeline Segment Name	Location	Mileage	California County or Counties
SYPS	CA-324	Las Flores Canyon Processing Facility to Gaviota Pump Station	10.86	Santa Barbara
SYPS	CA-325A	Gaviota Pump Station to Sisquoc Pump Station	38.72	Santa Barbara
SYPS	CA-325B	Sisquoc Pump Station to Pentland Station	74.84	Santa Barbara; San Luis Obispo; Kern

a. Description of CA-324 and CA-325

The CA-324 24-inch pipeline segment (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 LFC consolidated oil and gas processing facility and Gaviota Pump Station. This pipeline segment is located north of U.S. Highway 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 segment (formerly referred to as Line 903 – Gaviota to Sisquoc) is approx. 38.72 miles in length. This pipeline segment extends west from Gaviota Pump 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 segment then extends west and north from the Gaviota Creek MOV.

CA-325A continues west up a broad spur ridge to the ridge crest and the westerly boundary of Gaviota State Park. The pipeline segment 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 segment 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 segment 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 Pump Station at the southern end of Santa Maria Canyon.

The CA-325B 30-inch pipeline segment (formerly referred to as Line 903 – Sisquoc to Pentland) is approx. 74.84 miles in length. The pipeline segment follows Santa Maria Canyon after leaving the Sisquoc Pump 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 segment 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, CA-325B exits Santa Barbara County and enters San Luis Obispo County. The pipeline segment continues for approx. 44.5 miles through ranch land, terminating at the Pentland Station in Kern County.

Table 2-2 indicates High Consequence Areas (HCAs) along the Lines CA-324 and 325.

TABLE 2-2: HIGH CONSEQUENCE AREA SUMMARY

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

Lines CA-324 and 325 traverse multiple Counties as well as State and Federal land. Approximate mileage is included in Table 2-3, below.

TABLE 2-3: 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.

(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 SYPS pipeline facility that Sable operates, including segments CA-324 and 325 that are parts of the SYPS, are all interstate. CA-324 and 325 have potential to impact HCAs, including unusually sensitive areas. A map of the pipeline facility is included as Attachment A and further details about CA-324 and 325 and its right-of way are provided above.

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

a. *Pipeline Design and Construction Information*

The CA-324 segment was constructed from low carbon steel pipe. 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 2-4.

The CA-325A/B segment was constructed from low carbon steel pipe . 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 2-4.

TABLE 2-4: LINE PIPE SPECIFICATIONS

Pipeline Segment 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

b. Coating

Lines CA-324 and 325 are externally coated with the following coating system as illustrated in Figure 2-5:

- 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 2-5: 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 segments have 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 and new, deep well anode bed at Pentland Station, as well as over 140 test stations across the entire CA-324 and CA-325A/B pipeline segments. The PU insulation and PE tape wrap has the ability to "shield" the cathodic protection, such that 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. fusion bonded epoxy (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.[2] Additionally, the use of modern, advanced in-line inspection technologies, along with explicit integrity management programs and procedures for robust characterization, validation, and stringent 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 external corrosion risks associated with shielding of CP are described in subsequent sections in this Application.

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

a. Operating Information and Leak History

Lines CA-324 and 325 were previously owned and operated by Plains All American Pipeline LP to transport crude oil, and were formerly known as Lines 901 and 903, respectively. These pipeline segments have remained under "active" status pursuant to PHMSA's Part 195 regulations,[3] but have not transported crude oil since May 19, 2015.

Prior to May 19, 2015, there were no releases from CA-324 or 325 which met reportable criteria under PHMSA's Part 195 standards. On May 19, 2015, CA-324 (then known as 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 to detect and mitigate corrosion

[2] As noted in PHMSA ADB-2016-04, 81 Fed. Reg. 40398, 40400 (June 21, 2016), pipelines with coatings that result in cathodic protection "shielding" may nonetheless still be in compliance with 49 C.F.R. Part 195 subpart H. CA-324 and 325 have not been previously determined as out of compliance with any cathodic protection or corrosion control regulations in Part 195, nor is it apparent that there is any such regulation in Part 195 with which these segments' cathodic protection system do not comply. As noted elsewhere in this application, even to the extent there were such regulations, the same conditions proposed to be established through this special permit would properly address any integrity risks presented by the limited effectiveness of cathodic protection on CA-324 and 325, and fulfill the Consent Decree's and CAO's directive to obtain a special permit for these purposes.

[3] See Pipeline Safety: Clarification of Terms Relating to Pipeline Operational Status, 81 Fed. Reg. 54,512 (Aug. 12, 2016) ("The regulations consider pipelines to be either active and fully subject to all relevant parts of the safety regulations or abandoned.") See also, PHMSA December 17, 2025 Determination of Interstate Classification, p.3, n.8, confirming active status of Las Flores Pipeline.

- 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 Order (CAO) to the operator (Plains).[4] PHMSA's third amendment to the CAO provided options for how the operator could address the risks associated with shielded cathodic protection and CUI.[5] Specifically, PHMSA provided that the operator could mitigate these risks through a special permit that included a "long-term continuous monitoring plan to address the ineffective CP under insulation."[6] That amended CAO provided that the CUI plan must be based on one of several specified methods, including submitting a request for a Special Permit containing the following provisions to "mitigate the threat of CUI":

1) Accelerated reassessments;

2) Usage of the appropriate, complementary assessment tools for all threats, including stress corrosion cracking;

3) Coordination of data from the appropriate alternating ILI technologies;

4) More stringent repair criteria targeted at CUI; and

5) Advanced data analysis techniques to account for the potential growth of CUI including interaction criteria for anomaly assessment.[7]

This Special Permit Application includes provisions to address all of these topics, as noted further below.

On October 14, 2020, the Consent Decree was entered by the United States District Court for the Central District of California.[8] The Consent Decree adopted relevant remaining provisions of PHMSA's Corrective Action Order in Appendix D, section 1.[9]

In October 2022, Pacific Pipeline Company (PPC), then a subsidiary of ExxonMobil, acquired CA-324 and 325 from Plains. In 2024, Sable acquired PPC and currently serves as the designated operator of CA-324 and 325, as well as other components of the SYPS pipeline facility.

Maximum Operating Pressure (MOP) information for CA-324 and 325 is provided in Table 2-6.

---

[4] Plains Pipeline, LP, CPF No. 5-2015-5011H, Corrective Action Order (May 21, 2015), subsequently amended on June 3, 2015, November 12, 2015, and June 16, 2016.
[5] Amendment No. 3 to the Corrective Action Order, Item 2 (c), p.8, CPF No. 5-2015-5011H (June 16, 2016).
[6] *Id.*
[7] *Id*. See also PHMSA ADB-2016-04, 81 Fed. Reg. 40398, 40400 (June 21, 2016).
[8] *United States et al v. Plains All American Pipeline, LP et al*, no. 2:20-CV-02415 (C.D. Cal. Oct. 14, 2020).
[9] *Id*. at 91 ("All outstanding corrective actions in PHMSA's closed Corrective Action Order (CAO), CPF No. 5-2015-5011H, as amended, are hereby merged into this Consent Decree…").

TABLE 2-6: DOCUMENTED MOP and %SMYS[10]

Pipeline Designation	%SMYS	Documented MOP (psig)
CA-324	55.8%	1003 (maximum) (1.5 x MOP Spike test (15 mins) = 1505 psi; 1.25 x MOP strength test (8 hrs) = 1254 psi)
CA-325A	69.3%	1000 (maximum) (1.39 x MOP spike test (15 mins) = 1390 psi 1.25 x MOP strength test (8 hrs) = 1250 psi)
CA-325B (MP 49.57-107.55)	71.5%	1292 (1.25 x MOP strength test (8 hrs) = 1615 psi)
CA-325B (MP 107.55-124.42)	72.0%	1170[11] (1.25 x MOP strength test (8 hrs) = 1463 psi)

b. *Most Recent Testing and Assessment Results*

i. Hydrostatic Testing

CA-324 was originally hydrostatically pressure-tested on November 25, 1990 to 1765 pounds per square inch gauge (psig), as calculated at the highest elevation. CA-325A was originally 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. CA325B was originally hydrostatically pressure-tested within eleven separate sections 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.

Sable hydrostatically pressure-tested Segments CA-324 and 325 from March 30 through May 27, 2025, dividing the lines in 8 sections. Segments CA-324 and CA-325A were spike-tested as well to 150% and 139% of MOP, respectively. No test failures occurred during the 2025 hydrostatic

[10] MOP for the pipeline is adjusted by the change in elevation at that location compared to the lowest elevation in each section where the MOP is established. CA-324 and CA-325A each have one MOP low elevation point where MOP is established. CA-325B has two MOP control points. Test pressure for each segment is based upon the MOP at the low point for each pipe section.
[11] Test pressure for this segment was based on the maximum allowable MOP limited by 72% SMYS at the lowest elevation of the pipe.

tests or spike tests. These pressure test results combined with 2022 and 2023 ILI assessments, discussed in the following section of this application and repairs performed according to the more stringent Consent Decree criteria at Appendix B, section 4.A.1 of the Consent Decree, provide a high degree of assurance that CA-324 and CA-325 are fit to resume service.[12]

A summary of the percent of specified minimum yield strength (% SMYS) and the corresponding MOP, as established by the construction hydrotest records, is included above in Table 2-7. A summary of hydrotest records by segment are included in Table 2-8.

TABLE 2-8: HYDROSTATIC TEST SUMMARY

Pipeline Segment	Location	Date	Begin Station	End Station	Type	High Point Min Pressure (psig)	Low Point Max Pressure (psig)	Elevation Adjusted MOP (psig)
CA-324	Las Flores Sta	5/12/25	0+00	573+75	Spike (150%)	1166	1514	1003
					8-hour (125%)	915	1264	1003
CA-325A	Gaviota Sta	5/27/25	554+21	1337+21	Spike (139%)	872	1400	1000
					8-hour (125%)	730	1260	1000
	MP 25.71	3/30/25	1338+21	2602+76	Spike (139%)	800	1289	1000
					8-hour (125%)	660	1149	1000
CA-325B	Sisquoc Sta	4/13/25	2603+76	3186+76	8-hour (125%)	892	1625	1292
	MP 60.63	4/14/25	3187+76	3914+76	8-hour (125%)	751	1614	1292
	MP 74.44	4/22/25	3915+76	4455+76	8-hour (125%)	1209	1379	1292
	MP 84.65	5/2/25	4456+76	5669+76	8-hour (125%)	922	1253	1292
	MP 107.64	5/9/25	5670+76	6554+49	8-hour (125%)	459	1473	1170
	Pentland Sta							

[12] See, e.g., NACE Publcation 10A392, "Effectiveness of Cathodic Protection on Thermally Insulated Underground Metallic Structures," Sept. 2006 at p. 8 (appended to Line 901 Failure Investigation Report), available at https://www.phmsa.dot.gov/foia/plains-pipeline-lp-line-901-failure-investigation-report ("The use of internal pipeline corrosion inspection tools to locate/detect metal loss on external metallic surfaces has been relatively successful in evaluating corrosion control" and recommending "When practical, the thermally insulated metallic surfaces need to be inspected at routine time intervals for metal loss (e.g., an internal pipeline inspection tool could be used"); PHMSA ADB-2016-04, 81 Fed. Reg. 40398, 40400 (June 21, 2016),

ii. In-Line Inspection History

The following Table 2-9 provides a summary of CA-324, CA-325A, and CA-325B 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). Also note that CA-325A Gaviota to Sisquoc, and CA-325B Sisquoc to Pentland, have been inspected since the 2015 release, with axial magnetic flux leakage (MFL-A) surveys in September and October 2023, respectively.

TABLE 2-9: IN LINE INSPECTION SUMMARY

Pipeline Segment	Date of Inspection	Technology	Vendor
CA-324	6/18/07	Def+MFL+IMU	Rosen
	7/3/12	Def+MFL+IMU	Rosen
	5/6/15	Def+MFL+IMU	Rosen
	2/23/22	CMFL	Baker Hughes
	12/10/22	UTWM	Baker Hughes
CA-325A	1/1/03	Def+MFL+IMU	Tuboscope
	3/20/08	Def+MFL+IMU	Rosen
	4/29/13	Def+MFL+IMU	TD Williamson
	9/20/23	AMFL	Baker Hughes
CA-325B	10/1/94	Unknown	Tuboscope
	1/8/03	Def+MFL	Tuboscope
	10/21/06	Def+MFL	Tuboscope
	3/10/12	Def+MFL	TD Williamson
	6/12/13	AMFL	TD Williamson
	10/1/23	AMFL	Baker Hughes

The 2022 and 2023 assessments listed above were run in nitrogen. These tools were selected specifically to identify internal and external corrosion anomalies as well as potential clusters of anomalies. During April 2024 to May 2025, Sable repaired all defects as required under 49 C.F.R. § 195.452 as well as the more stringent repair criteria set out in Appendix B, section 4.A.1 of the Consent Decree. Altogether, Sable conducted approximately 170 digs and made over 200 pipeline repairs based on the 2022 and 2023 assessments.

To account for the possibility of any continuing external corrosion, Sable has proposed in Condition 10 to run an ILI tool within 7 days of steady state operation upon restart. Moreover, Sable has also proposed significantly increased ILI tool runs in Condition 14 to evaluate the pipeline for external corrosion and other threats. Finally, Sable has proposed stringent repair criteria for any defects detected through these assessments, in Conditions 16-17.

c. Other Activities

In addition to hydrostatic and spike testing and ILI assessments and associated anomaly repairs, Sable has conducted several additional activities on or relating to the pipeline to further mitigate the risk and consequences of a spill.

EFRD Analysis and Valve Installation. Pursuant to Appendix B, Section 10.A of the Consent Decree, analyses to determine the need for emergency flow restricting devices (EFRDs) had been performed, and Sable actioned these results by installing a total of 27 new safety valves along CA-324 and 325. These safety valves serve to limit the spill volume in the event of a rupture, reflecting best available technology to minimize spill volume pursuant to California AB 864.

Pipeline Control and Leak Detection. Sable has installed an API 1130-compliant Real Time Transient Model Computational Pipeline Monitoring (RTTM CPM) leak detection system, to limit release detection time and further minimize release volumes in the event of a leak. The RTTM CPM system also reflects best available technology to minimize spill volume pursuant to California AB 864. Sable also has installed new flow meters at Gaviota and Sisquoc Pump Stations to increase detection resolution of the leak detection system by providing flow data via the pipeline's supervisory control and data acquisition (SCADA) system to the control center, and installed additional pressure transmitters for enhanced pressure surveillance as integrating with the leak detection system. Sable has further installed an automatic shutoff system (ASOS) that would automatically initiate a pump shutdown sequence and valve closures upon receipt of a rupture alarm as indicated by the above and other existing instrumentation on CA-324 and 325.

Updated Programs and Procedures. Pursuant to the Consent Decree, Sable has implemented enhancements to its control room management (CRM) procedures and operations, including point-to-point verification reviews for each component of its SCADA system, and updated piping and instrumentation diagrams, software, manuals, and operating procedures to confirm they reflect existing field configuration. Sable has also made enhancements to the pipeline master control room, including adjusting alarm thresholds to better account for topography, sensor location, and to integrate with the above control and leak detection capabilities. Sable has also implemented updated integrity management procedures to reflect the more stringent assessment, data integration, and anomaly repair requirements in the Consent Decree.

Enhanced Spill Response Resources. Sable has developed a Tactical Response Plan to supplement its existing Incident Contingency Plan, with a focus on furthering emergency response preparation and planning within coastal zones and high pressure areas along the segments. Further, Sable has undertaken enhanced engagement with local emergency responders, including the Santa Barbara County Fire Department.

These actions collectively demonstrate that these segments and the overall pipeline is fit to resume operation. In addition to these activities that have established pipeline integrity today, Sable will continue to provide integrity assurance in future years through application of comprehensive conditions proposed in this application, which go well beyond what is required in Part 195.

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

Sable seeks relief from 49 C.F.R. § 195.452(h)(4)(iii)(H), requiring remediation within 180 days of discovery of corrosion of or along a longitudinal seam weld.[13]

Moreover, Sable is seeking this Special Permit pursuant to Appendix B Sections1.A and B and Appendix D, Sections 1.b.10 and 1.f of the Consent Decree, stating that a "State Waiver" for limited effectiveness of cathodic protection must be applied for and received prior to restarting Lines 901 and 903 (now CA-324 and 325).[14] As noted in PHMSA ADB-2016-04, 81 Fed. Reg. 40398, 40400 (June 21, 2016), pipelines with coatings that result in cathodic protection "shielding" may nonetheless still be in compliance with 49 C.F.R. Part 195 subpart H.

Given that CA-324 and 325 were then-considered intrastate at the time of the Consent Decree but are now considered interstate (removing any regulatory jurisdiction of OSFM over these

[13] Waiver of this provision does not fully obviate the need for Sable to repair corrosion of or along a longitudinal seam weld. Sable will still be required to remediate corrosion and other anomalies according to the remaining criteria in § 195.452(h) and the enhanced anomaly criteria in this proposed special permit.

[14] CA-324 and 325 have not been previously determined as out of compliance with any cathodic protection or corrosion control regulations in Part 195, nor is it apparent that there is any such regulation in Part 195 with which these segments' cathodic protection system do not comply. As noted elsewhere in this application, even to the extent there were such regulations, the same conditions proposed to be established through this special permit would properly address any integrity risks presented by the limited effectiveness of cathodic protection on CA-324 and 325, and fulfill the Consent Decree's and CAO's directive to obtain a special permit for these purposes.

pipelines), Sable interprets these provisions to require obtaining a special permit from PHMSA for limited effectiveness of cathodic protection prior to restarting CA-324 and 325. Sable already received an Emergency Special Permit and State Waivers from OSFM pursuant to this language of the Consent Decree. Sable now seeks a Special Permit from PHMSA that substantially carries over the conditions entered in the Emergency Special Permit and the State Waivers.

(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;

A. General External Corrosion Under Insulation

CA-324 and 325 were shut down in 2015 following the above-described release on CA-324. A Consent Decree was entered by the US District Court for the Central District of California on October 14, 2020, that requires a State Waiver prior to restarting CA-324 and CA-325A/B. CA-324 and 325 are comprised of buried and insulated pipe. The pipeline has a coal-tar coating system and insulation wrap that provides corrosion deterrence.

Sable seeks approval to manage external corrosion risk on CA-324 and 325 through a supplemental combination of more frequent 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. As noted above, the Consent Decree specifically incorporated the outstanding requirements of a CAO (as amended), which provided that a long-term CUI plan as part of restart could be based on a special permit that included the above measures. Table 4-1 below summarizes each of these measures and the proposed condition number(s) in Attachment B of this Application that address them.

TABLE 4-1: SUMMARY OF CAO CUI PLAN REQUIREMENTS AND CORRESPONDING SPECIAL PERMIT CONDITIONS

CAO Special Permit-based CUI Plan Requirement	Proposed Special Permit Condition Number(s) (see Appx. B) and Summary
Accelerated reassessments	*Condition 14(c):* Requires two Ultrasonic Wall Measurement (UTWM) ILI assessments per year for the first two years following restart, then, at minimum, annual ILI assessments thereafter, to assess metal loss, including due to corrosion. Part 195 only requires such

	integrity assessments on a once-per-five year schedule, and the Special Permit Segments were previously only assessed on a once-per-three year schedule. The higher assessment frequency established in the Special Permit will facilitate the timely detection and repair of such anomalies before they pose integrity risks. *Condition 14(d):* Requires, at minimum, annual Ultrasonic Shear Wave Crack Detection (USCD) ILI assessments. Part 195 only requires such assessments on a once-per-five year schedule. The higher assessment frequency established in the Special Permit will facilitate the timely detection and repair of such anomalies before they pose integrity risks. *Condition 14(e):* Requires running high-resolution deformation ILI tool along with each UTWM ILI assessments
Usage of the appropriate, complementary assessment tools for all threats, including stress corrosion cracking	*Condition 14(c) and (e):* UTWM tools are appropriate specifically to assess metal loss anomalies arising from the threat of internal or external corrosion, the latter of which is a special threat due to limited effectiveness of cathodic protection on the Special Permit Segments. Moreover, high-resolution deformation tools are appropriate to assess anomalies resulting from threats of geological or other external force threats (e.g., erosion and ground movement), or construction anomalies. *Condition 14(d):* USCD tools are appropriate to detect crack-based anomalies due to, among other things, stress corrosion cracking.
Coordination of data from the appropriate alternating ILI technologies;	*Condition 14(i)-(k):* Requires ILI tool vendor to determine tool tolerance per API 1163 2^{nd} Ed. and include that tolerance in determining the size of each indication reported to Sable. Sable must account for this tool tolerance and anomaly growth rates in scheduling repairs and future reassessment intervals, and must demonstrate ILI tool accuracy for each run by using calibration, excavations, and unity plots demonstrating tool accuracy meets the vendor's specifications (typical for depth within 10% accuracy for 80% of

	the time). Sable must perform at least four validation digs in accordance with Level 2 of API 1163.
More stringent repair criteria targeted at CUI	*Conditions 16-17:* Requires immediate repair of crack or crack-like anomalies equal to or greater than 50% of wall thickness (vs 80% threshold in § 195.452(h)(4)(i)). Requires 180-day repair of all internal or external metal loss anomalies with an ILI-reported depth of 40% wall loss or more, including tool tolerance (vs 50% wall loss threshold in § 195.452(h)(4)(iii)(F)).
Advanced data analysis techniques to account for the potential growth of CUI including interaction criteria for anomaly assessment	*Condition 18:* Requires Sable to develop a corrosion growth rate procedure to annually calculate corrosion growth rates between successive ILI assessments, including the most accurate signal matching between ILI data sets. *Condition 21(b)-(f):* Requires Sable to field-analyze a sample of assessment-identified anomalies to compare, and to apply 6t by 6t interaction criteria, and to use an approved third-party to review all ILI reports, verification dig results, unity plots, field findings, and any other finding that could affect the integrity of the Special Permit Segments within 6 months of each ILI assessment.

Each of the components of the special permit approach to a long-term CUI plan are addressed by the conditions of this proposed Special Permit. The proposed Special Permit is appropriate to mitigate risks associated with limited effectiveness of cathodic protection.

B. 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."[15] 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 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 noted above, 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 corrosion that preferentially attacks the seam. 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 Sable only accepts calls from circumferential magnetic flux leakage (MFL-C), spiral magnetic flux leakage (SMFL), ultrasonic crack detection (UTCD) and/or electromagnetic 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.

CA-324 was inspected using an 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 pipeline, Sable is therefore requesting PHMSA to issue a special permit which allows for the use of engineering analysis

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

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.

(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 beyond Part 195 to maintain the integrity of the pipeline, including measures specific to SSWC. Many of these measures were negotiated and agreed upon as part of the Consent Decree.

A comprehensive list of these proposed measures is contained in draft Special Permit conditions, at Attachment B. These measures include, among other things, temperature limitations and monitoring, hydrostatic testing, including spike test, requirements (which Sable has already completed), a five-fold more frequent than required by § 195.452 ILI assessment schedule, a substantially more stringent set of anomaly repair criteria, corrosion growth rate analysis, in-field direct examination, and additional recordkeeping and reporting requirements, as compared to the baseline Integrity Management requirements in Part 195. These measures, in their totality, in addition to hundreds of recently completed anomaly repairs under the repair conditions of the Consent Decree, will substantially minimize the possibility that future conditions that threaten the integrity and safety of the pipeline will go undiscovered or unremediated.

(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

Grant of the Special Permit would create positive impacts on affected stakeholders and operating the covered pipeline segments in accordance with the special permit would be in the public interest. Grant of the Special Permit would be consistent with operation of CA-324 and 325, which would help address the national energy emergency that has been declared by the President in Executive Order (EO) 14156 (January 20, 2025), which recognizes the seriousness of the West Coast energy shortage, and seeks to boost domestic energy production to address the shortage. Specifically, EO 14156 determined and declared pursuant to the National Emergencies Act (50 U.S.C. 1601 et seq) that the energy production and transportation capacity of the United States “are all far too inadequate to meet our Nation’s needs” and that “hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.” EO 14156 specifically notes that these problems “are most pronounced in our Nation's Northeast and West Coast, where dangerous State and local policies jeopardize our Nation's core national defense and security needs and devastate the prosperity of not only local residents but the entire United States population." EO 14156 concludes that our nation's "insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy," and that "in light of these findings, [the President] hereby declare[s] a national emergency."

Grant of the Special Permit helps address the energy security and supply issues that acutely affect the West Coast, as noted in EO 14156 by supporting operation of a vital source of crude oil transportation to local and regional refineries (amounting to 10-15% of current California-wide production levels), and helps reverse unfavorable market conditions for refineries. It would also help displace the need for imported oil and gasoline from other nations to California. See Attachments C-F for additional materials in support of these benefits.

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

Sable certifies that operation of CA-324 and 325 under the requested special permit is not inconsistent with pipeline safety and maintains equivalent or greater protection than that prescribed under 49 C.F.R. Part 195.

(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

As discussed, PHMSA previously granted an Emergency Special Permit to Sable, and this application seeks to carry forward substantially the same conditions as the Emergency Special Permit and the two existing state waivers issued by OSFM on December 17, 2024. A copy of the Emergency Special Permit is attached to this application at Attachment G.

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

This application does not seek 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 CA-324 and 325. Further, this cathodic protection system continues to achieve the specifications provided in § 195.571 and the applicable sections it references in NACE SP 0169-2007, as well as other corrosion control regulations in Part 195. Rather, Sable 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.

CA-324 and 325 have not been previously determined as out of compliance with any cathodic protection or corrosion control regulations in Part 195, nor is it apparent that there is any such regulation in Part 195 with which these segments' cathodic protection system do not comply. As noted elsewhere in this application, the same conditions proposed to be established through this special permit would properly address any integrity risks presented by the limited effectiveness of cathodic protection on CA-324 and 325, and fulfill the Consent Decree's and CAO's directive to obtain a special permit for these purposes.

As noted above, Sable already received an Emergency Special Permit on December 23, 2025 and State Waivers from OSFM in December 2024 (which PHMSA evaluated and approved) regarding waiver of the same standards for CA-324 and 325. Sable is seeking from PHMSA a special permit to supersede the Emergency Special Permit, which contains substantially the same conditions as reflected in the Emergency Special Permit and State Waivers (with adjustments for tasks already completed by Sable).

Sable includes a proposed Draft Environmental Assessment with this application, at Attachment G.

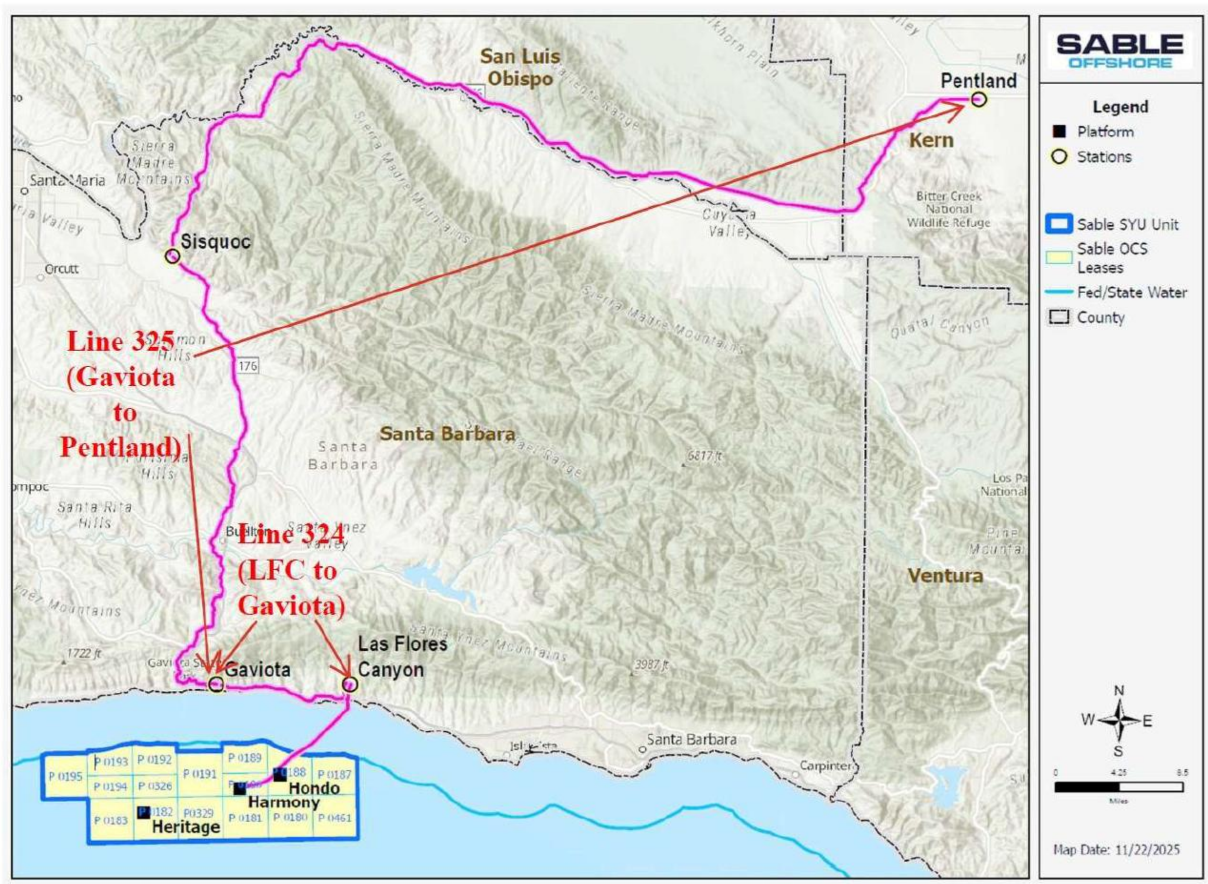
Sable believes that the proposed Special Permit reflects a conservative and measured approach to the identification and remediation of external corrosion metal loss features on CA-324 and 325, will adequately manage risk factors associated with cathodic protection, and enable safe, long-term operation of the pipeline.

We appreciate PHMSA's consideration of this Application. Should you have any questions, or require anything further to conduct your review of this Application please do not hesitate to contact me.

Sincerely,

J. Caldwell Flores
President and Chief Operating Officer, Sable Offshore Corp.
President, Pacific Pipeline Company

Attachment: A: Lines CA-324 and 325 System Map



Attachment B:
Proposed Special Permit Conditions

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

DRAFT SPECIAL PERMIT

Special Permit Information:

Docket Number:	PHMSA-[]
Requested By:	Sable Offshore Corp.
Operator ID #:	40881
Original Date Requested:	January 22, 2026
Original Issuance Date:	Date
Code Section(s):	49 CFR § 195.452(h)(4)(iii)(H)

Proposed Grant of Special Permit:

By this order, subject to the terms and conditions set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS)[1] proposes to grant this special permit to Sable Offshore Corp. (Sable) for two hazardous liquid pipelines (Lines CA-324 and CA-325) that are constituents of the interstate Santa Ynez Pipeline System (SYPS) pipeline facility, located on the Outer Continental Shelf (OCS) and in California.

I. Purpose and Need:

Sable sought this special permit to waive requirements of 49 CFR §195.452(h)(4)(iii)(H) as applicable to Lines CA-324 and CA-325. The regulation requires remediation within 180 days of discovery of corrosion of or along a longitudinal seam weld. These pipelines present a risk of such corrosion under insulation that may occur as a result of limited effectiveness of cathodic protection due to shielding effects of polyurethane foam and polyethylene tape wrap installed on these pipelines. Sable proposes an alternative approach to appropriately manage this risk, which approach was previously reviewed and

[1] Throughout this special permit, the usage of "PHMSA" or "PHMSA OPS" means the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety.

approved under an Emergency Special Permit granted by PHMSA on December 23, 2025 and as part of State Waivers issued by the California Office of State Fire Marshal (OSFM) on December 17, 2024 to Sable for segments CA-324 and CA-325.

Sable also sought this special permit to implement the terms of a Consent Decree entered in Civil Action No. 2:20-CV-02415 by the US District Court for the Central District of California, which provides, among other things, that a "State Waiver" for the limited effectiveness of cathodic protection must be applied for and received from OSFM prior to restarting Lines CA-324 and 325. Moreover, the Consent Decree incorporates outstanding requirements from the closed Corrective Action Order at CPF No. 5-2015-5011H, as amended, which includes a requirement to include in a Restart Plan a long-term CUI plan based on one of several methods, including obtaining a special permit that requires: 1) accelerated reassessments; 2) usage of the appropriate, complementary assessment tools for all threats, including stress corrosion cracking; 3) coordination of data from the appropriate alternating ILI technologies; 4) more stringent repair criteria targeted at CUI; and 5) advanced data analysis techniques to account for the potential growth of CUI including interaction criteria for anomaly assessment.[2] This Special Permit addresses each of these requirements through imposing conditions that require substantially more frequent integrity assessments as compared to Part 195, each of which must use threat-appropriate tools (including for wall loss anomalies from external and internal-based corrosion and for detecting crack anomalies from conditions such as stress corrosion cracking). This Special Permit also establishes more stringent anomaly repair criteria as compared to under Part 195. Further, this Special Permit requires integrating data from integrity assessments to continuously gauge assessment performance through comparison with in-the-field and other comparative benchmarks, and requires the performance of a corrosion growth rate analysis to inform Sable's analysis of integrity assessment data.

CA-324 and 325 were formerly considered intrastate at the time of entry of this Consent Decree, and were regulated by OSFM pursuant to its state certification received under 49 USC § 60105(a). However, these pipelines are now considered interstate pursuant to Sable's designation on November 26, 2025, and PHMSA's concurrence on December 17, 2025, of the SYPS as an interstate pipeline facility. As a result, PHMSA, and not OSFM, is the sole pipeline safety regulatory agency with authority to grant waiver of the pipeline safety regulations. This change in designation immediately affected the measures implemented in the two State Waivers issued by OSFM for CA-324 and 325 in December 2024. To address any regulatory gaps between the transition of regulatory oversight from OSFM to PHMSA and respond to the ongoing national energy emergency, PHMSA issued an Emergency Special Permit that

[2] See also PHMSA ADB-2016-04, 81 Fed. Reg. 40398, 40400 (June 21, 2016),

contained substantially the same conditions as the State Waivers on December 23, 2025. Sable then requested a special permit pursuant to 49 U.S.C. § 60118(c)(1) and 49 CFR § 190.341 to provide an ongoing basis for the waiver requested by Sable and the operation of CA-324 and 325 after the expiration of the Emergency Special Permit. The requested conditions in the special permit application are substantially the same as those approved in the Emergency Special Permit.

II. Special Permit Segments

This permit pertains to the specified special permit segments and corresponding special permit inspection area defined in this section.

Special Permit Segments:

Special Permit Segment Name	Location	Mileage	California County or Counties
CA-324	Las Flores Canyon Processing Facility to Gaviota Pump Station	10.86	Santa Barbara
CA-325A	Gaviota Pump Station to Sisquoc Pump Station	38.72	Santa Barbara
CA-325B	Sisquoc Pump Station to Pentland Station	74.84	Santa Barbara; San Luis Obispo; Kern

III. Conditions

PHMSA proposes to grant this special permit subject to Sable implementing each of the following conditions. These conditions must be implemented and complied with in addition to all applicable requirements of 49 CFR Part 195 except for compliance with requirements in 49 CFR §195.452(h)(4)(iii)(H).

General Conditions:

1) The Special Permit Segments may only be used to transport crude oil.

2) Prior to transporting crude oil in the Special Permit Segments, Sable must develop and implement procedures for the conditions and requirements described in this emergency special permit.

3) Sable shall not exceed maximum operating pressure (MOP) limits for the Special Permit Segments, as follows:

a) The MOP of Line CA-324 cannot exceed 1003 pounds per square inch gauge (psig).

b) The MOP of Line CA-325A (the segment of Line CA-325 between Gaviota and Sisquoc stations) cannot exceed 1000 psig.

c) The MOP of Line CA-325B (the segment of Line CA-325 between Sisquoc and Pentland stations) cannot exceed 1292 psig.

4) Sable shall not exceed maximum operating temperature limits for crude oil transported in the Special Permit Segments, as follows:

a) The maximum operating temperature of the crude oil that is transported in Line CA-324 must not exceed 140 degree Fahrenheit for more than 12 consecutive hours.

b) The maximum operating temperature of the crude oil that is transported in Line CA-325A (the segment of Line CA-325 between Gaviota and Sisquoc stations) must not exceed 125 degrees Fahrenheit for more than 12 consecutive hours. Temperature transmitters must be installed on Line CA-325 at Gaviota station to monitor the temperature of Line CA-325A.

c) The maximum operating temperature of the crude oil that is transported in Line CA-325B (the segment of Line CA-325 between Sisquoc and Pentland stations) must not exceed 110 degrees Fahrenheit for more than 12 consecutive hours. Temperature transmitters must be installed on Line CA-325 at Sisquoc station to monitor the temperature of Line CA-325B.

5) This special permit does not relieve Sable from complying with applicable requirements under 49 CFR Part 195, other than those waived in this special permit.

6) This special permit 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 inspections (ILIs) performed pursuant to this special permit must include:

a) Use of a tool that is at least capable of reliably detecting and identifying cluster corrosion and general corrosion, defined 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-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)[3], and the HF-ERW long seam weld on the pipe to represent the fracture toughness of 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 11, 16, 17, and 21. Sable may use pipe samples taken opportunistically during ongoing maintenance and repair efforts on Line CA-324.[4]

9) Prior to placing Line CA-325 (including CA-325A and CA-325B) 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.

---

[3] The heat affected zone (HAZ), as used in this special permit, is defined as a 1-inch-wide area on either side of the longitudinal weld seam.

[4] Sable indicated in its application that it has already completed all of the testing required in this condition. Sable must submit all fracture toughness results to PHMSA prior to restarting Line CA-324.

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), 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 11, 16, 17, and 21. Sable may use pipe samples taken opportunistically during ongoing maintenance and repair efforts on Line CA-325A/B.[5]

10) All existing immediate and 180-day repair conditions must be evaluated and remediated pursuant to the Consent Decree repair criteria prior to restarting CA-325A/B.[6] Upon restart 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 PHMSA. Sable must utilize the Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) results to identify, evaluate and remediate any immediate and 180-day repair conditions that are listed in this emergency special permit.

11) 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.

12) Sable must utilize cleaning pigs at regular intervals not to exceed a biweekly basis to maintain adequate cleanliness on the internal pipe wall of the Special Permit Segments.

13) Pressure Testing:[7]

---

[5] Sable indicated in its application that it has already completed all of the testing required in this condition. Sable must submit all fracture toughness results to PHMSA prior to restarting Line CA-325.

[6] Sable indicated in its application that it has already completed the repairs required in this sentence. Sable must submit all of the results to PHMSA prior to restarting CA-324 and CA-325.

[7] Sable indicated in its application that it has already completed all of the testing and repairs required in this Condition. Sable must submit the results to PHMSA prior to restart and confirm that no failures occurred during the required pressure testing.

a) Prior to placing CA-324 in operation, Sable must conduct a spike hydrostatic pressure test of CA-324 at a minimum pressure that is at least 1.5 times the maximum operating pressure (MOP) or 100% specified minimum yield strength (SMYS), for a minimum of 15 minutes after the spike test pressure is stabilized. Sable must field evaluate and remediate the following anomalies before performing the spike hydrostatic test on CA-324:

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

b) Immediately following the spike hydrostatic pressure test specified in Condition 13(a), Sable must conduct an 8-hour hydrostatic pressure test of CA-324 at a minimum of 1.25 times the MOP.

c) Prior to placing Line 325A (segment of Line 325 between Gaviota and Sisquoc stations) in operation, Sable must conduct a spike hydrostatic pressure test of *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:

   i. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.
   ii. All anomalies that have a predicted failure pressure less than or equal to 1.5 times MOP.

d) Immediately following the spike hydrostatic pressure test specified in Condition 13(c), Sable must conduct an 8-hour hydrostatic pressure test of CA-325A at a minimum of 1.25 times the MOP.

e) Prior to placing Line 325B (segment of Line 325 between Sisquoc and Pentland stations) in operation, Sable must conduct a hydrostatic pressure test of *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:

i. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.

ii. All anomalies that have a predicted failure pressure less than or equal to 1.4 times MOP.

f) Sable must obtain the Test ID for each hydrostatic pressure test from PHMSA (or OSFM if such testing was performed prior to November 26, 2025) and have the approved independent testing firm forward separately the certified test results to PHMSA or the OSFM, as applicable.

g) 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 PHMSA or OSFM (as applicable) approved hydrostatic testing companies.

h) Failures resulting from the spike hydrostatic pressure test or the 8-hour strength test shall be immediately reported to PHMSA.[8]

i) Section(s) of the Special Permit Segments that failed during the required hydrotesting must be repaired by removing and replacing the failed section. PHMSA reserves the right to revoke this special permit if failure(s) raise the concern that the Special Permit Segments cannot be safely operated.

14) In-Line Inspection (ILI) Assessment and Frequency:

a) Prior to performing in-line inspections of the Special Permit Segment, Sable shall provide PHMSA with a written notification to describing its assessment plan with the following information:

i. Dates for integrity assessment

ii. In-line inspection tool(s) selected, in accordance with API Standard 1163 Section 5 and NACE SP0102[9] 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;

iii. In-line inspection tool vendor(s)

iv. Required tool specifications including operational specifications and anomaly sizing tolerances

---

[8] All submissions to PHMSA required by this special permit shall be submitted through email to the OPS Western Region Director, Dustin Hubbard, email address: Dustin.Hubbard@dot.gov or his designee.

[9] Industry standards referenced in this special permit must utilize the editions that are incorporated by reference in 49 CFR 195.3 unless another edition is explicitly specified in this special permit.

v. Tool validation methodology

vi. Anomaly feature identification criteria and reporting thresholds – wall loss, dents, internal corrosion, external corrosion, cracks, and crack-like indications

vii. Criteria used to identify locations for excavation and field verification

viii. Non-destructive examination

b) 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.

c) Metal Loss Tool(s):

i. Initial ILI tool runs – Each year, during the first two (2) years of operating the Special Permit Segments, 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.

ii. Subsequent ILI tool runs – After the first two (2) years of operating the Special Permit Segments, 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 Special Permit Segment within 30 days after it was deemed to be unsuccessful. All metal loss tool runs must also utilize an Inertial Measurement Unit (IMU).

d) 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[10] or the ILI assessment must be assessed at more frequent intervals if condition 21 determined a shorter assessment interval.

  i. These crack tool runs must utilize an Inertial Measurement Unit (IMU) and must be able to detect and size axial and circumferential cracks.

  ii. USCD Performance Specification Requirements

    1. The USCD tools must have a probability of detection that is ≥ 90% for axial and circumferential cracks.

    2. 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.

    3. 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.

    4. The depth sizing accuracy for cracks must be ± 0.8 mm for axial cracks and ± 1 mm for circumferential cracks.

e) Dents and Pipe Deformation: Sable shall conduct a high-resolution deformation ILI tool with each UTWM.

f) 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 Special Permit Segment in which the ILI tool velocity was outside of the specified tool velocity range.

g) All ILI tool runs must obtain the Test ID from PHMSA prior to a run.

h) 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.

i) 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.

---

[10] Sable may petition PHMSA 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 PHMSA approval.

j) 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[11] 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.

k) 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).

15) Discovery of Condition: The discovery date must be within 180 days of any ILI tool run for each type of ILI tool.

16) Immediate Repair Conditions:[12]

a) A crack or crack-like anomaly that meets any of the following criteria:

i. Crack or crack-like anomaly that is equal to or greater than 50% of pipe wall thickness.

ii. 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.

b) Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.39 times the MOP.

c) Any external cluster corrosion or external general corrosion that is located on the remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.[13]

---

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

[12] The criteria specified in this special permit is supplemental to, and does not relieve Sable from complying with, the requirements set forth in 49 CFR 195.452(h)(4)(i). All immediate repair conditions must be remediated with a permanent repair method.

[13] 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.

17) 180-Day Repair Conditions:[14]

a) A crack or crack-like anomaly that has predicted failure pressure of less than 1.5 times the MOP.

b) Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.

c) 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.[15]

d) 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.

18) Corrosion Growth Rate Analysis (CGRA):

a) 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 Special Permit Segments is maintained.[16] The timing of remediations under this condition shall be based on the most recent calculation of short-term corrosion rates.

b) The CGRA procedure must include ILI data matching methods[17] to analyze data from successive ILI's, methodologies for growth rate calculations and errors from comparing ILI data.

c) Sable must identify the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss.

---

[14] The criteria specified in this special permit is supplemental to, and does not relieve Sable from complying with, the requirements set forth in 49 CFR 195.452(h)(4)(iii), except for those associated with 49 CFR 195.452(h)(4)(iii)(H). All immediate repair conditions must be remediated with a permanent repair method.

[15] 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 PHMSA, 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 PHMSA.

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

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

d) 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.[18]

e) 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.

19) Pressure Reduction: If Sable is unable to perform field evaluation and remediation of any required conditions within the time limit conditions specified in this special permit, 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.

20) In Field Direct Examination of Pipe:

a) Direct examinations[19] 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).[20] PAUT must be used for sizing any crack or crack-like anomaly lengths and depths.

b) 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:

i. Method 5 must not be used on metal loss anomalies that are in the HAZ, girth weld, or longitudinal seam weld.

ii. 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.

iii. 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.

---

[18] 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.

[19] 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.

[20] Direct examinations for ILI reported crack or crack-like indications must include a magnetic particle inspection complemented by shear wave technology or inspection by phased array ultrasonic testing.

c) 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.

d) 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.[21]

e) 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.

21) Integrity Management:

a) A fracture mechanics and pressure cycling evaluation is required for un-remediated cracks and crack-like indications detected by ILI or indirect inspection tools.

i. 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).

ii. 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).

b) 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.

c) When sizing metal loss indications, apply interaction/clustering criteria of 6t by 6t for applicable ILI tool(s).

d) 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.

[21] The coating procedure must be submitted to PHMSA prior to the effective date of this emergency special permit.

e) 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 Special Permit Segments. The review must be conducted within six (6) months of each ILI assessment. The third-party expert must be approved by PHMSA prior to being selected.

f) 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.[22]

22) Data Requirements for Predicted Failure Analysis:

a) 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.

b) The analyses performed in accordance with this special permit must utilize pipe and material properties of the pipe body and longitudinal weld seam that are documented in *traceable, verifiable, and complete* records.

23) Recordkeeping:

a) Procedures, records of investigations, data, analyses, and other actions made in accordance with the requirements of this special permit shall be kept for the life of the Special Permit Segments and must be submitted to the PHMSA, in the manner requested (electronic, hardcopy, or other format) within 30 days.

b) Sable must maintain the following records:

i. Technical approach used for the analysis
ii. All data used and analyzed
iii. Pipe and longitudinal weld seam properties
iv. Procedures used to implement special permit conditions

---

[22] Sable indicated in its application that it has already completed the evaluation required in this condition. Sable must submit results to PHMSA prior to restarting Line CA-324 and 325.

v. Evaluation methodology used
vi. Models used
vii. Direct in situ examination data
viii. All in-line inspection tool assessments information evaluated
ix. Pressure test data and results
x. All in-the-ditch assessments performed on the Special Permit Segments
xi. All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operations results
xii. All finite element analysis results
xiii. The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting methodology
xiv. The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods
xv. Safety factors used for fatigue life and/or predicted failure pressure calculations
xvi. Reassessment time interval and safety factors
xvii. The date of the review
xviii. Confirmation of the results by qualified technical subject matter expert(s)
xix. Approval by responsible Sable management personnel
xx. Records of additional preventive and mitigative (P&M) measures performed
xxi. Reports required by this special permit.

24) Reporting:

a) Any release on the Special Permit Segments shall be reported to the PHMSA at the earliest practicable moment following discovery but no later than 24 hours from the time of discovery.[23]

b) An email notification shall be made at least three (3) days prior to a Special Permit Segment being exposed for non-emergency purposes of field evaluation and repair to PHMSA. The email notification shall include, if applicable:

i. Tool type and run date
ii. Unique identifier (e.g. Dig Number, Joint Number, Flaw ID, Condition Type)
iii. Dig sheets
iv. Field contact information for Sable
v. Time and location of the field evaluation and repair.

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

c) Sable shall provide a Summary of Conditions Report within 210 days of the last date of an ILI run to PHMSA and include:

i. Tool type
ii. Run date
iii. Summary of Conditions Report[24]
iv. Final Vendor Report and Pipe Tally

d) Sable shall provide a report to PHMSA by June 15th of every year for the duration of this special permit. At a minimum, the annual report shall contain the following, if applicable:

i. A Closure Report for the previous calendar (CY) which contains:
   1. Features that were remediated in previous CY, including documentation for in-the-ditch assessments and repairs
   2. Identify features that remain to be assessed
   3. Unity Plots for previous ILI runs

ii. Fracture mechanics and pressure cycling analyses in accordance with Condition 21(a);
iii. The third-party ILI expert reviews in accordance with condition 21(e).
iv. AC and DC Interference surveys that are due in accordance with condition 21(f).
v. A copy of the CGRA for prior year including:
   1. Mean corrosion growth rate for the Special Permit Segments
   2. Distribution graph of the corrosion growth rate for the Special Permit Segments (e.g. occurrences (#) vs. corrosion rate (mpy)

25) Limitations:

a) This special permit is limited to a term of ten (10) years from the date of issuance. If Sable elects to seek renewal of this special permit, Sable must submit its renewal request at least 180 days prior to expiration of this ten (10) year period to PHMSA pursuant to 49 CFR 190.341(f). The renewal application must demonstrate that the special permit is still consistent with pipeline safety. PHMSA may seek additional information from Sable prior to granting any request for the special permit renewal.

b) Should Sable fail to comply with any conditions of this special permit or should PHMSA determine that this special permit is no longer appropriate or is inconsistent with pipeline

[24] PHMSA 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.

safety, PHMSA may revoke the special permit and require Sable to comply with all appropriate regulatory requirements.

c) PHMSA may order the Special Permit Segments to be shutdown if appropriate pursuant to its authority under 49 U.S.C. § 60112.

d) PHMSA 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 special permit. The terms and conditions of any compliance order shall take precedence over the terms of this special permit.

e) In the event of conflict between the conditions of this special permit and industry standards, the special permit conditions shall prevail.

f) If Sable sells, merges, transfers or otherwise disposes of all or part of the assets covered by the special permit, Sable must provide the PHMSA written notice of the change within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the special permit.

Attachment C:

Declaration of Michael A. Mische

Case No. 25-CV-02247 (Sup. Ct. Cal. July 18, 2025)

ALSTON & BIRD LLP
JEFFREY D. DINTZER, SBN 139056
jeffrey.dintzer@alston.com
MATTHEW C. WICKERSHAM, SBN 241733
matt.wickersham@alston.com
GARRETT B. STANTON, SBN 324775
garrett.stanton@alston.com
350 South Grand Avenue, 51st Floor
Los Angeles, CA 90071
Telephone: (213) 576-1000
Facsimile: (213) 576-1100

PAUL HASTINGS LLP
DUNCAN JOSEPH MOORE, SBN 233955
djmoore@paulhastings.com
BENJAMIN J. HANELIN, SBN 237595
benjaminhanelin@paulhastings.com
NATALIE C. ROGERS, SBN 301254
natalierogers@paulhastings.com
1999 Avenue of the Stars, 27th Floor
Century City, California, 90067
Telephone: (310) 620-5879
Facsimile: (310) 620-5899

Attorneys for Real Parties in Interest
SABLE OFFSHORE CORP. and PACIFIC PIPELINE COMPANY

SUPERIOR COURT OF THE STATE OF CALIFORNIA

COUNTY OF SANTA BARBARA

ENVIRONMENTAL DEFENSE CENTER, et al., Petitioners and Plaintiffs, v. CALIFORNIA DEPARTMENT OF FORESTRY AND FIRE PROTECTION, et al., Respondents and Defendants, and SABLE OFFSHORE CORP., et al., Real Parties in Interest.	Case No. 25CV02247 [Coordinated with Case No. 25CV02244] Assigned for all purposes to: Hon. Donna D. Geck **DECLARATION OF MICHAEL A. MISCHE IN SUPPORT OF REAL PARTIES' OPPOSITION TO PRELIMINARY INJUNCTION** [*Filed concurrently with Opposition to Preliminary Injunction; Declarations of Steve Rusch, Bart Leininger, Brien Vierra, and Michael J. Rosenfeld*] Date: July 18, 2025 Time: 10:00 AM Dept.: 4 Complaint Filed: April 15, 2025 Trial Date: None Set

TABLE OF CONTENTS

LIST OF FIGURES

I. INTRODUCTION AND QUALIFICATIONS

A. Assignment and Scope of Work Performed

1. I have been retained as an expert on certain aspects of the oil and gas industry for Sable Offshore Corp., a Delaware corporation, and its three offshore platforms, and Pacific Pipeline Company, a Delaware corporation ("Plaintiffs" or collectively, "Sable") with specific reference to Las Flores Pipelines CA-324 and CA-325 (collectively the "Las Flores Pipeline System") in matters regarding the Center for Biological Diversity and Wishtoyo Foundation's efforts to challenge the California Office of the State Fire Marshal's approval of modified regulatory requirements, known as "State Waivers," to Sable.[1] I have based my analysis and have formulated my conclusions and opinions on my academic and professional training and experiences, and would and could testify in court on my analysis and to these conclusions and opinions. I make this declaration and provide the opinions stated below based upon my experience and my personal knowledge and would and could testify to the matters contained herein.

2. The scope of work for which I was retained involved the collection, assessment, and structuring of data necessary to perform an economic analysis to determine why the production of oil from Sable's offshore platforms and use of its Las Flores Pipeline System would not irreparably harm the public and why preventing the use of the Las Flores Pipeline System to carry Sable's production to market will instead irreparably harm the citizens of California, including the residents of Santa Barbara County. In addressing the scope and performing the work of this assignment, I interrogated data and various literature and analyzed a series of pertinent issues, including but not limited to:

   a. Describing the general economic behavior of the oil and gas industry.

   b. Describing the historical and current status of oil production in the state of California.

---

[1] *Center for Biological Diversity and Wishtoyo Foundation v. California Department of Forestry and Fire Protection, et al.* (Santa Barbara Sup. Ct. April 15, 2025), Case No. 25CV02244.

c. Describing California's in-state oil production and its dependency on foreign, non-U.S. oil sources.

d. Estimating the costs of imports of non-U.S. oil from foreign sources to California.

e. Determining the potential economic impact that the addition of Sable oil production from its three offshore platforms and the use of its Las Flores Pipeline System could potentially have on in-state oil production and overall California oil supplies.

f. Comparing the potential breakeven of Sable oil production from its three offshore platforms and the use of its Las Flores Pipeline System at variable production scale, as compared to other California in-state producers and offshore producers.

g. Determining to which markets Sable oil production from its three offshore platforms and the use of its Las Flores Pipeline System could potentially represent the most viable for Sable to sell or trade its oil.

h. Assessing the capacity and capacity utilization of each of Sable's pipelines (Line CA-324 and Line CA-325) for the transporting of oil produced by Sable's three offshore platforms to its potential markets.

i. Estimating the reserves, capacities, and long-term viability of each of Sable's platforms (wells) for oil production.

j. Comparing the total estimated aggregated GHG emissions by Sable from the production of oil from its three offshore platforms to other comparable in-state sources and to comparable non-U.S. crude oil sources, inclusive of maritime vessel transportation.

k. Estimating and describing the potential direct and indirect economic impact of oil production based on Sable's three offshore platforms and the use of its Las Flores Pipeline System on California state revenues, and Santa Barbara, Kern, and San Luis Obispo Counties.

l. Estimating and describing the potential direct and indirect employment impact of oil production based on Sable's three offshore platforms and the use of its Las Flores Pipeline System, on Santa Barbara, Kern, and San Luis Obispo Counties.

My work and the opinions expressed herein are restricted to the performance of this assignment and of the scope of work performed described above, and I express no opinion on any other matters that are external to the purview of this Assignment and Scope of Work Performed.

B. Qualifications and Background

3. I am an Associate Professor of Management and Professional Practice at the Marshall School of Business, University of Southern California ("USC") in Los Angeles, CA. I am currently also a Co-Founder and Chairman of the Board of Synergy Consulting Group, Inc., a management consulting firm. I hold a B.S. degree with honors in finance and economics from New York University and an MBA from Stern School of Business, New York University. I also hold an MS degree in Federal Taxation from Golden Gate University and a certification in AI from the Massachusetts Institute of Technology.

4. I have over 40 years of experience in the management consulting industry and 28 years in higher education. Prior to joining the USC faculty, I had two decades of experience in the management consulting industry. From 1983 to 1992, I worked at KPMG, one of the largest global accounting and consulting firms in the world, and eventually became one of the youngest consulting partners (*i.e.*, "Principals") elected in the history of KPMG. At KPMG, I was a member of the Practices & Methods Review Committee. My practice focused on, among other things, strategy and transformation, transaction management services, and innovation and advanced technologies. From 1991 to 1993, I also served as a Principal of Management Consulting Services at A.T. Kearney, one of the leading

management consulting firms in the world. From 1995 to 1997, I served as a consultant to the senior leadership of Andersen Consulting (now Accenture) for the development of several practice methodologies related to process transformation and innovation. I have served as Chairman of the Board since 1993 and CEO from 1995 through 2016 for Synergy Consulting Group, Inc. Throughout my consulting career, I have led and managed numerous consulting projects for a variety of clients in the private, public, and non-profit sectors, many of which involved benefit analysis and economic impact of strategies and strategic investments. I have consulted with a variety of industries and organizations, including Fortune 100 companies, elite management consulting firms and investment banks, national, state, and local governments, foreign governments, and heads of state and key policymakers.

5. Since becoming a faculty member at USC in 1997, I have taught numerous MBA courses on the management consulting industry and strategic change, including, among others, The Business of Energy in the 21st Century, Strategic Innovation & Change, Management Consulting, Strategic Transformation & Renewal, Case Analysis for Consultants, Organizational Behavior, and Leading High-Performance Teams. I am also responsible for USC's Certificate in Management Consulting Program and am a senior advisor to USC Management Consulting and Strategy Club, the largest club in the MBA program. I have received the Management and Organization Department Service Excellence Award and the Marshall Golden Apple Teaching Award. I have published eight books on management, organization, and consulting and have been cited in over 300 articles, interviews, reviews, and studies. I have also served as a material or expert witness several times. My academic and research interests in the oil and gas industry span over 50 years and began in October 1973 with the Arab Oil Embargo of the United States when I was a student at New York University.

6. A detailed list of my experience, publications, interviews, and prior expert work, including a list of my testimony in the past four years is included, as a true and correct copy, as **Exhibit A** to this report.

C. Materials and Evidence Considered

7. Addressing the objectives required extensive analysis of data and comparative analytical methods. The research involved in this work and in supporting the opinions expressed herein is widely available and includes but is not limited to verifiable sources such as the California Energy Commission, U.S. Energy Information Agency, Bloomberg, U.S. Department of Energy, Sable SEC filings, International Energy Agency, Plains All American Reports Fourth-Quarter and Full-Year 2023 Results; Announces 2024 Guidance, Oil & Gas Journal, American Petroleum Institute, the California Department of Tax and Fee Administration, the U.S. EPA, California Air Resources Board, Statista, The Federal Reserve Bank, the California Attorney General's Office, the California Legislative Analyst's Office, U.S. Department of Interior, Rystad Energy, Bureau of Labor Statistics, the U.S. Oil and Gas Association, and a number of scholarly research articles and papers.

8. In addition to the public materials, I relied upon the evidential and supporting documents associated with this action. By example and without limitation, these materials included Sable Investor Presentation, Cultivation Cap & Eligible Business License Applicants Lists|Santa Barbara County, CA., "Oil & Gas | CA State Lands Commission" found at https://www.slc.ca.gov/oil-gas/.

D. Compensation

9. Fee and compensation arrangements for this work are based on time and materials. My hourly rate for this assignment is $1,000.00, and payment for my services does not depend in any way on the opinions that I form or on the outcome of this matter. I have no equity interests in Sable Offshore Corp. or any of its affiliates. Furthermore, I have no interests or conflicts that may be related to any other oil and gas producer or any nation-state that drives most of its income from oil and gas. Like many people who have professionally managed pension plans, including those who are members of CalPERS, one of my pension funds may own the stock of one or several petroleum or petroleum-related companies. In this regard, I may have a distant and indirect interest, but in all situations, any interests are immaterial and

are not pertinent, and do not have any influence on my work and the opinions expressed in this declaration.

II. SUMMARY OF CONCLUSIONS

10. Based on the data, research into prevailing literature, and my analysis, my conclusion is that the production of oil from Sable's offshore platforms and the associated use of its Las Flores Pipeline System to carry Sable's production to market will not irreparably harm the public and will instead benefit the public. For the same reasons, preventing the use of the Las Flores Pipeline System from carrying Sable's production to market would irreparably harm consumers of gasoline, diesel and other byproducts of crude oil.

11. California is facing an energy crisis and has the highest retail gasoline and aviation fuel costs in the United States. On July 1, retail gasoline prices increased, further stressing consumers who live and work in a state with the highest housing and general cost of living. The addition of Sable's production oil from its three offshore platforms and the use of its Las Flores Pipeline System would increase in-state oil production to 360,000 barrels a day at a time when California is facing extreme uncertainty and price hikes in its fossil fuel energy sector. The addition of Sable's production and the use of its Las Flores Pipeline System would provide the foundation energy security and price certainty. California's current in-state crude production is just about 310,000[2] barrels per day, which provides less than a quarter of the state's total daily crude demand. The remaining supply, close to 950,000 barrels, is imported from foreign nations including Ecuador, Iraq, and Saudi Arabia.[3] Raising in-state output to a 360,000 barrels a month, which could be achieved through SYU production and operation of the Las Flores Pipelines, would allow California to operate more independently

[2] Commission, C. E. (n.d.). Annual Oil Supply Sources To California Refineries. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/annual-oil-supply-sources-california

[3] Commission, C. E. (n.d.-b). Foreign Sources of Crude Oil Imports to California 2020. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/foreign-sources-crude-oil-imports

and would reduce the State's exposure to geopolitical risks and moderate exposures to spot market price hikes that adversely affect California consumers.

12. The production of oil from Sable's three offshore platforms and the use of Sable's Las Flores Pipeline System to transport its offshore production to market would have a favorable economic impact on California's overall energy situation, as well as have a favorable influence on local employment and tax revenues and consumer retail gasoline, diesel, and aviation fuel prices, and would improve and strengthen California's energy and economic security. Furthermore, the addition of Sable oil production to the market would have ancillary benefits reaching across state lines into Nevada and Arizona and would, in effect, strengthen and improve national defense readiness for U.S. military forces stationed in California, Nevada, and Arizona that are reliant on California refineries for aviation, gasoline and diesel fuels.

13. Allowing Sable to transport SYU-produced crude to market through the Las Flores Pipeline System would significantly benefit the public by serving as the economic "backbone" while navigating the economic uncertainties and risks associated dependency on non-U.S. foreign oil suppliers of energy transformation in support of California's ambitions for energy transformation.

III. ANALYSIS

A. Understanding Petroleum

14. Petroleum is derived from crude oil. Crude oil, or simply 'crude,' is a fossil fuel and the product of millions of years of geological activity and organic decay. Oil deposits are found in the ground, either onshore or offshore, at the bottom of an ocean, lake, or river. To locate deposits, oil producers expend considerable effort and funds to explore and "discover" petroleum deposits, which are reservoirs, pockets or patches of oil, or oil fields. Once located, the oil must be extracted, usually via drilling.[4] The extracted oil is then transported via maritime vessels, pipelines, trucks, or rail tankers to a processing facility, which prepares the petroleum for refinement. The refining process turns crude oil into various products, such as gasoline, diesel fuel, aviation fuels, heating oils, and other derivatives.

15. The standard measure for crude oil is a barrel, which contains 42 gallons or 159 liters. As a general rule and as an informal estimate, one gallon of oil produces between .47 and .67 gallons of refined gasoline. Stated differently, one barrel of oil (42 gallons) yields 17-28 gallons of gasoline. On average, a barrel of oil, once refined, will yield 45 gallons of total product or about 1.1 times the original volume.[5] Additionally, a single barrel of crude oil typically produces 138,095 Btu of energy.[6]

16. Not all oil is alike, and there are multiple types of crude that define its quality and grade. Therefore, no two barrels of oil are exactly identical. Petroleum is characterized by its origin and its API rating.[7] A combination of factors — including geology, location,

[4] *Petroleum*. (n.d.). https://education.nationalgeographic.org/resource/petroleum

[5] EIA, Petroleum Supply Monthly, April 2019

[6] *Facts about Oil*. (2020). Www3.Uwsp.edu. https://www3.uwsp.edu/cnr-ap/KEEP/Documents/Activities/ Energy%20Fact%20Sheets/FactsAboutOil.pdf

[7] API Definition: According to the American Petroleum Institute, the API rating is "An arbitrary scale expressing the gravity or density of liquid petroleum products." The higher the API gravity (rating), the lighter the oil. In general, light oil crude has an API rating of 38 degrees or more. Intermediate or medium grade oil has an API gravity rating of 22 to 38 degrees. Crude oil with API ratings of 38 and above are considered heavy and extra heavy. The characterization of oil crude as "sweet" or "sour" is related to its sulfur content. See, *Table Definitions, Sources, and Explanatory Notes*. (n.d.). Www.eia.gov. https://www.eia.gov/dnav/pet/TblDefs/pet_pnp_crq_tbldef2.asp

chemistry, and climate — makes each type of oil unique, possessing specific properties that can be refined for intended uses. For example, oil found in Texas can and will be different than oil in California. The predominant method for assigning a quality rating to crude oil is "gravity" (viscosity) as defined, measured, and rated using the standard established by the American Petroleum Institute (API).[8] Crude oils that rate 35-45 on the API scale are called "light crude" and are considered the highest quality and yield the highest value products from refining. Some crude oils are "sour and heavy to extra heavy," making them more costly to produce and refine into end products. In contrast, other crudes are "sweet and light/lite," which are less expensive to refine.

17. Crude oils rated at 15 or lower are characterized as "extra-heavy" and typically require more refining processes, are more costly to refine, and yield lower outputs. Extra heavy crudes are typically used for purposes other than gasoline, diesel, and jet fuel production. Crude oils with high sulfur content are generally referred to as "sour," while those with lower sulfur content are characterized as "sweet." Hence, in discussing oil, the term "Light sweet crude" would be used to describe an oil that has a high API rating and low sulfur content. The quality and origin of oil also influence the amounts of greenhouse emissions, as do extraction processes, transportation and distribution methods, and refining efficiencies associated with the oil and the production of end products, such as gasoline. **California generally produces, and its refineries use, heavier crudes.**

[8] *Oil categories*. (n.d.). https://www.api.org/products-and-services/engine-oil/eolcs-categories-and-classifications/oil-categories

Figure 1

California Sources, Grades & Transportation Methods for Crude Oil- 2018 to 2024		
Crude Oil Source	**Crude Grade Characteristic**	**Transportation Method to CA**
U.S. DOMESTIC		
CA- Kern	Very Heavy	Pipeline
CA- Midway Sunset	Very Heavy	Pipeline
CA- Berridge	Very Heavy	Pipeline
CA- San Ardo	Very Heavy	Pipeline
CA- Lost Hills	Light Heavy	Pipeline
CA- Offshore	Heavy	Pipeline
CA- Ventura	Light Heavy	Pipeline
CA- Elk Hills	Light Heavy	Pipeline
Alaska- North Slope	Medium	Tanker
Washington State	Gasoline	Tanker
FOREIGN		
Canada	Heavy	Tanker & Rail
Ecuador	Heavy	Tanker
Guyana	Medium/Heavy	Tanker
Russia	Heavy	Tanker
Saudia Arbia	Heavy	Tanker
Iraq	Heavy	Tanker

(Source: https://www.californiaenergyatlas.com/copy-of-crude-oil)

18. Generally, oil produced offshore in the Santa Ynez region (Santa Barbara Channel) is heavier crude with low API gravity and consistent with other California crudes. This grade of crude is typically used by California refineries in the production of fuels. Summarized above is a representative sample of the crudes produced in California as compared to the foreign oil imported by California to meet its daily needs.

B. Economic Role & Impact

i. Global

19. From heating, cooking, and lighting to the manufacturing of cellular telephones, agricultural production, electrical power generation, plastics, asphalt, concrete, medical

devices and pharmaceutical products, and alternative energy production, petroleum is essential to any economy and modern society. Although oil is universally known as a source of energy, petroleum is used in the manufacturing of fibers, such as polyester and nylon, certain types of medical devices, the screens that are used in monitors, televisions, cell phones, computers, cement, asphalt, wind turbines, steel, herbicides, and fertilizers.[9] Petroleum, in the form of gasoline, diesel, and aviation fuels, is essential to transportation and the movement of people, products, and food.

20. Globally, the amount of oil in the world fluctuates based predominantly on three factors: (1) consumption (demand), (2) production from existing proven sources, and (3) the discovery of new oil sources (reserves). For example, in 1960, crude oil reserves were estimated to be around 291 billion barrels.[10] In 2023, world crude reserves were estimated to range between 1.5 to 1.73 trillion barrels of oil.[11] [12] [13] Reserve oil is petroleum that has been discovered and properly approximated (proven) but not yet been harvested (produced). The majority of proven reserves, around 79%, are located in OPEC member countries.[14]

21. In 2023, around 101.81 million barrels of oil were produced globally per day.[15] For perspective, around <u>1.2 million barrels of oil are consumed on Earth per second</u>.[16] For

---

[9] IOGP. (2022, October 11). *Oil and gas in everyday life*. https://www.iogp.org/workstreams/advocacy/oil-natgas-in-everyday-life/

[10] Statista. (2024, July 23). *Global crude oil reserves 1960-2023*. https://www.statista.com/statistics/236657/global-crude-oil-reserves-since-1990/

[11] Ibid.

[12] Chen, J. (2024, July 25). Oil reserves. Investopedia. https://www.investopedia.com/terms/o/oil reserves.asp#:~:text=Oil%20reserves%20are%20an%20estimate,oil%20reserves%20in%20the%20 world.

[13] *World Oil Statistics - Worldometer*. (n.d.). https://www.worldometers.info/oil/

[14] OPEC. (2024). *OPEC : OPEC Share of World Crude Oil Reserves*. Opec.org; Organization of the Petroleum Exporting Countries. https://www.opec.org/opec_web/en/data_graphs/330.htm

[15] *Frequently Asked Questions (FAQs) - U.S. Energy Information Administration (EIA)*. (2024, April 11). Www.eia.gov. https://www.eia.gov/tools/faqs/faq.php?id=709&t=6.

[16] Calculation based on 86,400 seconds per day and 2023 consumption of 100.3 million barrels of oil a day.

2024, world production increased by around 1.2% to 103 million barrels a day.[17] According to the IEA, the energy sector, including the oil and gas industry, employs 65 million people worldwide (2019 est.), or about 2% of all global employment.[18] Oil represents the largest employment sector, with 8 million or 12% of total employment in the industry.[19] On a comparative basis, the energy sector has more highly skilled labor as a percentage of its labor force, 45%, than the overall average of all industries, which is 25% for highly skilled labor.[20]

22. According to the U.N., in 2023, a total of 12.3 billion tons of cargo was transported using maritime vessels, which represents around 80% of all global trade.[21] [22] **Maritime tankers burn bunker (heavy oil) fuels for propulsion, airplanes burn aviation fuels, trucks are powered by diesel fuels, mass-scale agricultural production is based on fossil fuels, and over 60% of automotive transportation is reliant on fossil fuels**. Around 49% to 50% of electrical power generation in the U.S. is derived from fossil fuels.[23]

Figure 2

[17] *Frequently Asked Questions (FAQs) - U.S. Energy Information Administration (EIA)*. (2024, April 11). Www.eia.gov. https://www.eia.gov/tools/faqs/faq.php?id=709&t=6.

[18] *World Energy Employment*. (n.d.). https://iea.blob.core.windows.net/assets/a0432c97-14af-4fc7-b3bf-c409fb7e4ab8/WorldEnergyEmployment.pdf

[19] *World Energy Employment*. (n.d.). https://iea.blob.core.windows.net/assets/a0432c97-14af-4fc7-b3bf-c409fb7e4ab8/WorldEnergyEmployment.pdf

[20] *World Energy Employment*. (n.d.). https://iea.blob.core.windows.net/assets/a0432c97-14af-4fc7-b3bf-c409fb7e4ab8/WorldEnergyEmployment.pdf

[21] UNCTAD. (2024, October 22). *Review of Maritime Transport 2024*. UNCTAD. https://unctad.org/publication/review-maritime-transport-2024.

[22] statista. (2017). *Topic: Ocean Shipping.* Www.statista.com; Statista. https://www.statista.com/topics/1728/ocean-shipping/

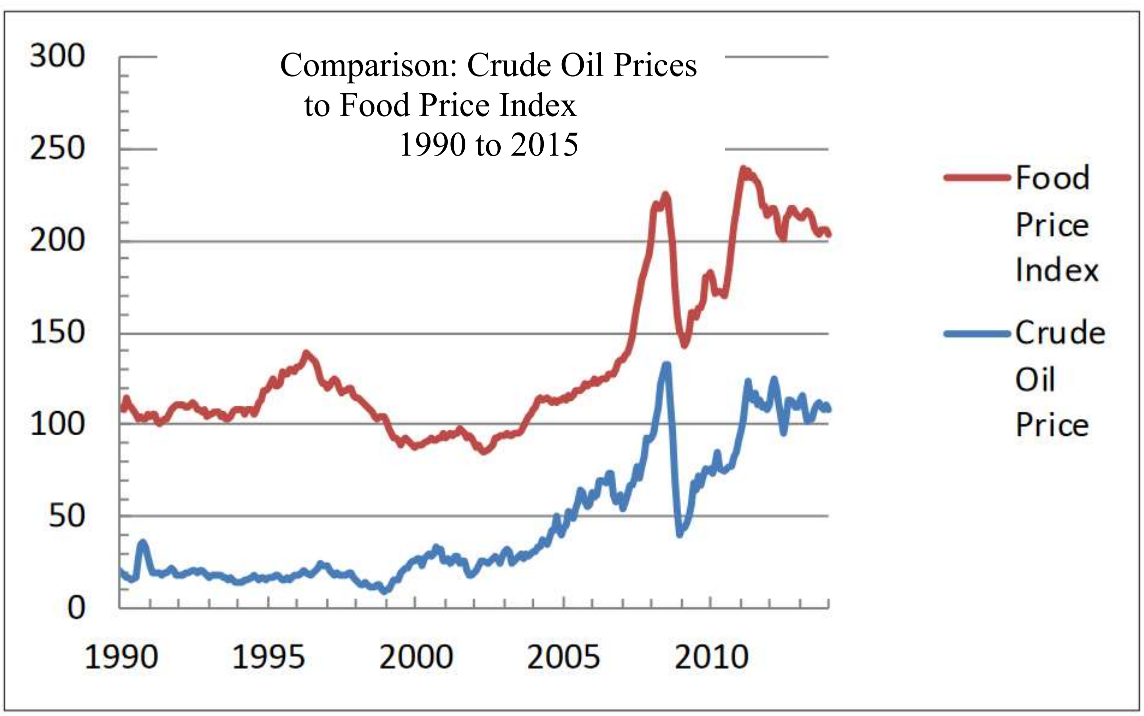
[23] U.S. Energy Information Administration. (2024, July 15). *U.S. Energy Facts Explained*. Eia.gov; U.S. Energy Information Administration. https://www.eia.gov/energyexplained/us-energy-facts/

2022/23- GLOBAL PRODUCTION & CONSUMPTION- TOP 10 NATIONS					
WORLD PRODUCTION- 2023			WORLD CONSUMPTION- 2022		
Nation	Million of Barrels per day	Percent of World Total	Nation	Million of Barrels per day	Percent of World Total
United States	21.91	22%	United States	20.01	20%
Saudi Arabia	11.13	11%	China	15.15	15%
Russia	10.75	11%	India	5.05	5%
Canada	5.76	6%	Russia	3.68	4%
China	5.76	6%	Saudi Arabia	3.65	4%
Iraq	4.42	4%	Japan	3.38	3%
Brazil	4.28	4%	Brazil	3.03	3%
United Arab Emirates	4.16	4%	South Korea	2.55	3%
Iran	3.99	4%	Canada	2.41	2%
Kuwait	2.91	3%	Germany	2.18	2%
Total Top 10	74.59	73%	Total Top 10	61.08	61%
World Total-Production	**101.81**		**World Total-Consumption**	**99.95**	

(Source: EIA. https://www.eia.gov/tools/faqs/faq.php?id=709&t=6)

23. Petroleum products, such as gasoline and diesel fuels, are significant components in the determination of the cost of food production and retail grocery prices. As indicated in the Figure below, as gasoline prices increased, the cost of staples such as milk, ground beef, and sugar also increased. As was indicated during the inflationary period of 2021 to 2024, when general inflation outpaced real wages and peaked at 9.1%, and crude oil and gasoline prices peaked at a 40-year high, food prices for consumers increased.

Figure 3



(Source: https://extension.psu.edu/fuel-ethanol-hero-or-villain#:~:text=Gasoline%20is%20not%20water%20soluble,performance%20if%20not%20dealt%20with)

24. Crude oil prices have a casual correlation to food prices. When crude prices increase and stay elevated for protracted periods, as they were during the 2020 to 2024 period, food prices, as well as overall costs, tend to also increase. As the research literature indicates, "oil and food price volatility causes macroeconomic instability and deteriorates the living conditions, particularly in developing countries where poor people spend most of their income to buy food."[24] Thus, when the price of crude oil and its related products, such as gasoline, increases, the price increases have a regressive and disproportionate impact on lower and fixed-income groups, as well as working-class families.

25. Longitudinal studies of the influence of crude oil on food prices indicate "statistically significant evidence in favor of the existence of a long-run causal relationship, solely running from oil prices to food prices."[25] One study calculated that a 1% increase in the crude oil price index results in food prices increasing by .08%.[26]

Figure 4

---

[24] Z. Zhang, L. Luanne, E. Cesar, W. Michael Food versus fuel: What do prices tell us? Energy Policy, 38 (1) (2010), pp. 445-451.

[25] Karakotsios, Achillefs, et al. "The Dynamic Linkages between Food Prices and Oil Prices. Does Asymmetry Matter?" *The Journal of Economic Asymmetries*, vol. 23, June 2021, p. e00203, https://doi.org/10.1016/j.jeca.2021.e00203. Accessed 9 June 2021.

[26] *Asymmetries*, vol. 23, June 2021, p. e00203, https://doi.org/10.1016/j.jeca.2021.e00203. Accessed 9 June 2021.

BRENT CRUDE & GASOLINE PRICES RELATIVE TO FOOD STAPLES	
Household Expenditures on Gasoline, Energy & Utilities	**2019-23 % Change**
Average Price of Brent Crude Oil	**29.08%**
Average Retail Gasoline Price-	**20.77%**
Average Price for #2 Diesel Fuel- CA.	37.36%
Average Retail Price of Gasoline- CA.	33.06%
Average Cost of Electricity- Residential Kilowatt	23.83%
Average Cost of Milk - July	41.78%
Average Price of Ground Beef- 1 lbs. - July	34.26%
Average Cost of Butter	12.27%
Average Cost of Ice Cream (.5 Gallon)	25.05%
Average Cost of Sugar- Per lbs.	107.42%

(Source: Author)

26. Increases in crude oil and crude oil product prices are of particular concern in California. Gasoline prices are highly correlated with crude oil prices, and in California, the costs are amplified by tight supplies and regulations. California's average retail gasoline prices, which are correlated to the price of crude oil, are routinely 40% to 50% higher than the national average. Not surprisingly, California retail gasoline prices are also considerably higher than its neighboring states. **Californians pay the highest gasoline prices in the United States**, and they went up on July 1, 2025, as a result of the state excise tax, new Low Carbon Fuel Standard, and ABX2-1, requiring refineries to maintain stock of finished gasoline, in addition to crude oil. Significantly, any disruption or interruption of crude oil supplies to the surviving California refineries will have a detrimental effect on consumer prices and a regressive and disproportionately harsh impact on lower and fixed income Californians.

27. . At 18.9% of its 39 million inhabitants, California has the highest poverty rate in the U.S. and has 24%, or over 187,000, of the total estimated 771,500 homeless people in the U.S. [27] [28] Furthermore, California's cost of living is around 12% than all other states,

[27] Torres, Mauricio. "New Census Data Show California Poverty Soared to Alarmingly High Levels in 2023." *California Budget and Policy Center*, 10 Sept. 2024, calbudgetcenter.org/news/new-census-data-show-california-poverty-soared-to-alarmingly-high-levels-in-2023/.

[28] Cremin, Sean. "Homelessness Hits Record High in California, Jumps Dramatically in Rest of US." *Public Policy Institute of California, 25 Mar. 2025*, www.ppic.org/blog/homelessness-hits-record-high-in-california-jumps-dramatically-in-rest-of-us/.

making it the highest cost of living in the U.S.[29] It's not just gasoline that Californians pay a premium for. According to California's own Legislative Analyst's Office ("LAO"), greenhouse emissions policies have contributed to the second highest monthly electricity rates for residential service in the U.S.[30] For the 2019 to 2024 period, the LAO reports that residential electrical utility rates in California increased by 47%. In the Golden State, Californians monthly utility bills average $438.[31] [32]

ii. United States

28. The U.S. oil and gas industry is an extensive, integral, and critical part of the U.S. economy and is vital to national defense and economic security. At $1.7 trillion, the oil and gas industry comprises around **8% of the U.S. GDP** and employs around 11.3 million people, representing 5.6% of total U.S. employment.[33] An additional 3.4 million jobs are

[29] Pino, Ivana. "This Map Compares the Cost of Living in Every State." *Yahoo Finance*, 28 Feb. 2025, finance.yahoo.com/personal-finance/banking/article/cost-of-living-by-state-164246058.html.

[30] Spady, A. (2025, January 8). California's "ambitious" policies to reduce greenhouse gases drive surge in electricity costs: report. *Fox Business*. https://www.foxbusiness.com/fox-news-politics/californias-policies-greenhouse-gases-electricity-surge

[31] https://www.foxbusiness.com/fox-news-politics/californias-policies-greenhouse-gases-electricity-surge

[32] Carey, R. (n.d.). *How much does it cost to live in California? Housing, utilities, and more*. Unbiased. https://www.unbiased.com/discover/banking/what-is-the-cost-of-living-in-california#:~:text=California's%20average%20cost%20of%20living,on%20top%20of%20your%20finances.

[33] American Petroleum Institute. (2019). *Oil & Natural Gas Contribution to U.S. Economy Fact Sheet*. Api.org. https://www.api.org/news-policy-and-issues/taxes/oil-and-natural-gas-contribution-to-us-economy-fact-sheet

See also, *New analysis: American-Made natural gas and oil drives U.S. economic recovery, Strengthens all industries*. (2021b, July 20). https://www.api.org/news-policy-and-issues/news/2021/07/20/2021-pwc-analysis associated with oil and gas affiliated industries and businesses.[34] In the U.S., the oil and gas industry hourly wages, on average, are around 85% higher than the national average.[35]

29. The oil and gas industry accounts for around 16% of total capital expenditures annually in the U.S.[36] In contrast, the transportation and healthcare sectors account for 5.3% and 6.3% of capital expenditures, respectively.[37] In the U.S., the EIA estimates that Americans spent around $1.0 trillion on energy, of which $503 million was related to gasoline, jet fuel, and diesel fuels in 2020, which collectively accounts for 4.8% of the U.S. GDP.[38] According to a Stanford University report, between 2020 and 2023, the global energy sector attracted around $9.8 billion in private investment in AI, with over half of that investment occurring in the United States.[39]

30. For 2022, the EIA reports that the U.S. has proven reserves of at least 48.3 billion barrels of oil.[40] Comparatively, **the United States has the 9th largest proven oil reserves in the world**. However, U.S. technologies and the opening of previously closed areas could significantly increase U.S.- proven reserves. Based on current and planned consumption rates

[34] *New analysis: American-Made natural gas and oil drives U.S. economic recovery, Strengthens all industries*. (2021, July 20). https://www.api.org/news-policy-and-issues/news/2021/07/20/2021-pwc-analysis

[35] American Petroleum Institute. (2019). *Oil & Natural Gas Contribution to U.S. Economy Fact Sheet*. Api.org. https://www.api.org/news-policy-and-issues/taxes/oil-and-natural-gas-contribution-to-us-economy-fact-sheet

[36] American Petroleum Institute. (2019). *Oil & Natural Gas Contribution to U.S. Economy Fact Sheet*. Api.org. https://www.api.org/news-policy-and-issues/taxes/oil-and-natural-gas-contribution-to-us-economy-fact-sheet

[37] American Petroleum Institute. (2019). *Oil & Natural Gas Contribution to U.S. Economy Fact Sheet*. Api.org. https://www.api.org/news-policy-and-issues/taxes/oil-and-natural-gas-contribution-to-us-economy-fact-sheet

[38] *2020 inflation-adjusted U.S. energy expenditures lowest since 2002*. (n.d.). Www.eia.gov. https://www.eia.gov/todayinenergy/detail.php?id=53620

[39] Stanford University. (2024). *The 2024 AI Index Report | Stanford HAI*. Stanford.edu. https://hai.stanford.edu/ai-index/2024-ai-index-report

[40] U.S. Energy Information Administration. (2017). *U.S. Crude Oil, Natural Gas, and Natural Gas Proved Reserves, Year-end 2017.* Eia.gov. https://www.eia.gov/naturalgas/crudeoilreserves/

and EIA current estimates, the U.S. has about 290 years of proven and technically recoverable oil reserves.[41]

C. California Petroleum

i. Economic Contributions

31. With a $3.9 trillion economy (GDP), California comprises 14% of the U.S. GDP, is the nation's largest state economy, and ranks 4th (nominal) as the largest economy globally.[42] [43] On a per capita basis, California would be the second-largest economy in the world.[44] In dollar terms, California's GDP exceeds the GDPs of Italy, the U.K., Canada, and France.[45] For the 1982 to 2023 period, and on a percentage change basis, California's GDP outgrew that of the overall U.S. by 1.06 times.[46] As California is the largest state economy in the nation, it stands to reason that the behavior of California's state economy is highly correlated with that of the overall U.S. GDP on an annual percentage change basis.[47]

---

[41] Ier. (2022, June 22). *Global Oil and Gas proved reserves increase in 2021 - IER*. IER. https://www.instituteforenergyresearch.org/fossil-fuels/gas-and-oil/global-oil-and-gas-proved-reserves-increase-in-2021/

[42] Duan, J., & Bohn, S. (2024, October 14). *California's Economy*. Public Policy Institute of California. https://www.ppic.org/publication/californias-economy/

[43] *California is now the 4th largest economy in the world | Governor of California*. (2025, April 24). Governor of California. https://www.gov.ca.gov/2025/04/23/california-is-now-the-4th-largest-economy-in-the-world/

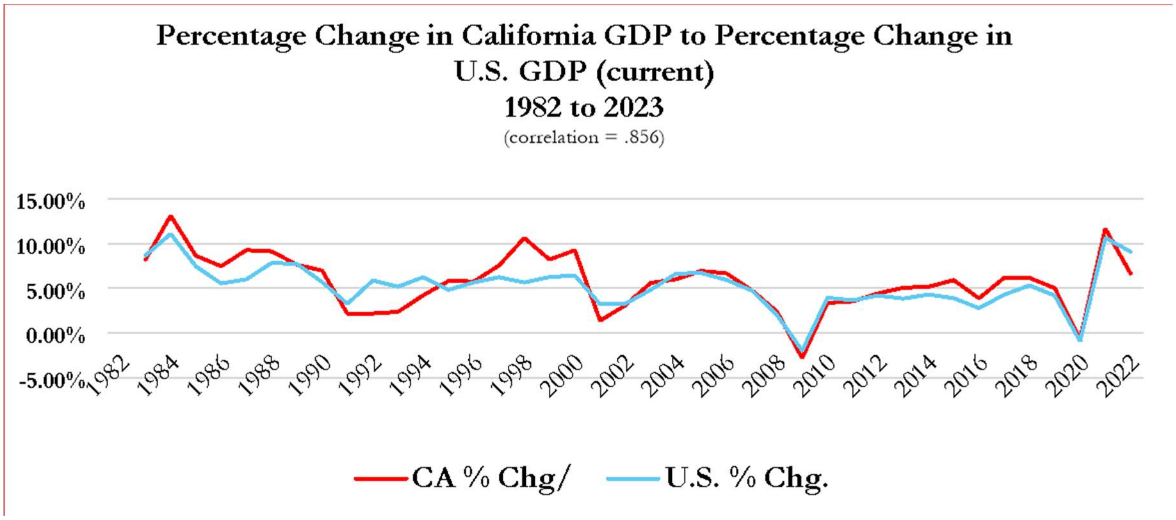
[44] Duan, J., & Bohn, S. (2024, October 14). *California's Economy*. Public Policy Institute of California. https://www.ppic.org/publication/californias-economy/

[45] Hughes, R. A. (2025, January 6). *If California were a country*. Bull Oak. https://bulloak.com/blog/if-california-were-a-country/

[46] Author calculation.

[47] Author calculation.

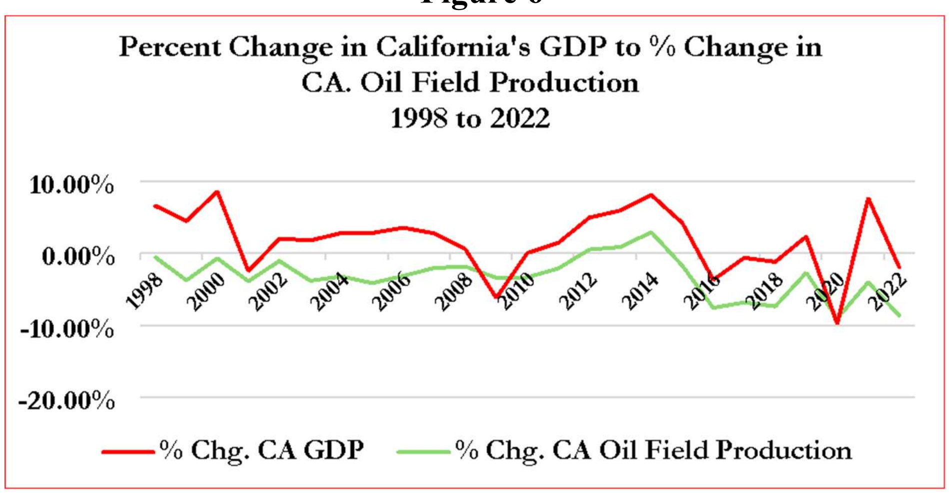
Figure 5



(Source: EIA, Fed. Reserve, author)

32. Over the 1998 to 2023 period, although there is some similarity in movement between California's oil field production to its GDP, based on the annual percentage change, the correlation is very low (.11). The low correlation is not unexpected, as oil and gas production has become less significant over the years in California's economy, as in-state production declines.[48].

Figure 6



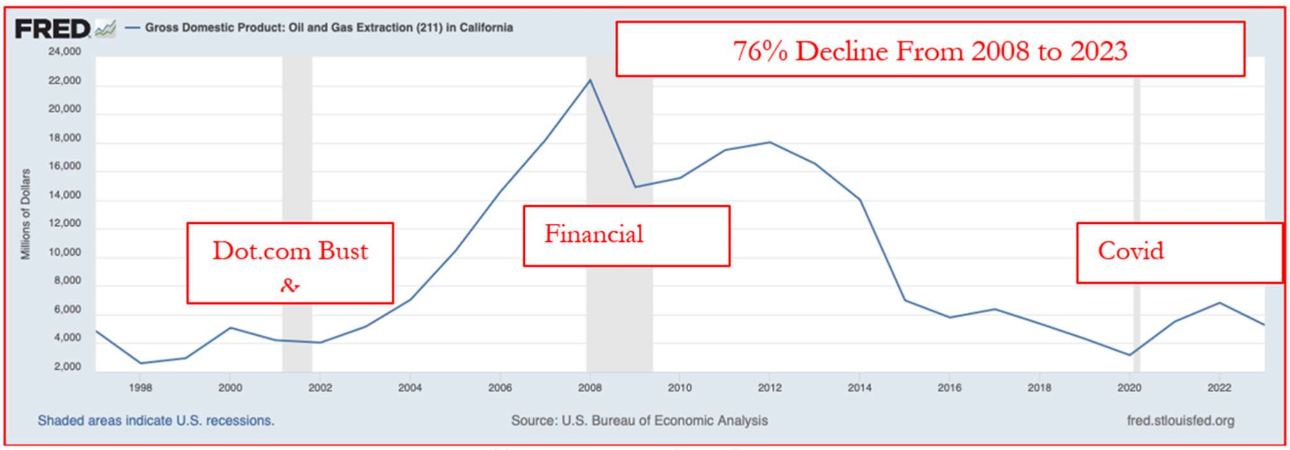
(Source: EIA, Fed. Reserve, author)

[48] *Gross Domestic Product: Oil and Gas Extraction (211) in California*. (2023). Stlouisfed.org. https://fred.stlouisfed.org/series/CAOILGASNGSP#

33. For 2022, the oil and gas industry generated around **$338 billion in total economic contribution, which comprised around 8% of the Golden State's GDP**.[49] For perspective, professional, financial, and information services at $520 billion are the largest.[50] As indicated in the chart below, oil production contribution to California's GDP reached a historical peak, in absolute dollars, in 2008. Since the 2008 peak, oil production's contribution to California's GDP, in absolute dollar terms, has declined by 76%, indicating a lesser role in the State's overall economy.[51]

Figure 7

California: Gross Domestic Product from Oil & Gas Extraction



(Source: https://fred.stlouisfed.org/series/CAOILGASNGSP#)

ii. Employment

34. Total direct employment affiliated with the oil and gas industry in California is estimated to be around **148,700, with indirect employment associated with California's oil**

[49] https://wspa.app.box.com/s/2v30dlvt0fbez09irhav001rw19tfh48

[50] *What is the gross domestic product (GDP) in California? | USAFacts*. (n.d.). USAFacts. https://usafacts.org/answers/what-is-the-gross-domestic-product-gdp/state/california/

[51] *Gross Domestic Product: Oil and Gas Extraction (211) in California*. (2023). Stlouisfed.org. https://fred.stlouisfed.org/series/CAOILGASNGSP#

and gas industry estimated to be around 536,770.[52] Collectively, total salaries and wages of California workers and employees directly affiliated with the oil and gas industry have generated over $23 billion in personal income and over $53 billion as related to indirect personal income associated with those employed in related industries and businesses.[53] In aggregate, the oil and gas industry has generated over $47.9 billion in state and local and $16.3 billion in federal tax revenues for 2022 (collectively $64.2 billion).[54]

35. Specifically, in California, the oil and gas industry creates and sustains premium-paying jobs across a broad spectrum of job classes, including union, non-union, professional, and skilled workers. For example, petroleum system pump operators, refinery operators, and gaugers earn, on average, $95,610, while gas and processing facility operators earn $105,000 annually.[55] In comparison, the typical wages for a construction worker in California average $44,310 annually, according to the California Department of Tax and Fee Administration (CDTFA).[56]

36. As of December 2023, California holds around 3.1% of all U.S.-proven reserves, ranks fifth largest oil reserves in the U.S., ranks 7th in oil production among 32 oil-producing states, and is home to the Monterey Shale Reserve.[57] Comparatively, California's in-state oil production is dwarfed by Texas, North Dakota, New Mexico, and Alaska. For perspective, Texas produced almost 18 times the amount of oil than California in 2022.

---

52 *Statewide_LAEDC_2025_factsheet-1.pdf | Powered by Box*. (2025). Box.com. https://wspa.app.box.com/s/2v30dlvt0fbez09irhav001rw19tfh48

53 *Statewide_LAEDC_2025_factsheet-1.pdf | Powered by Box*. (2025). Box.com. https://wspa.app.box.com/s/2v30dlvt0fbez09irhav001rw19tfh48

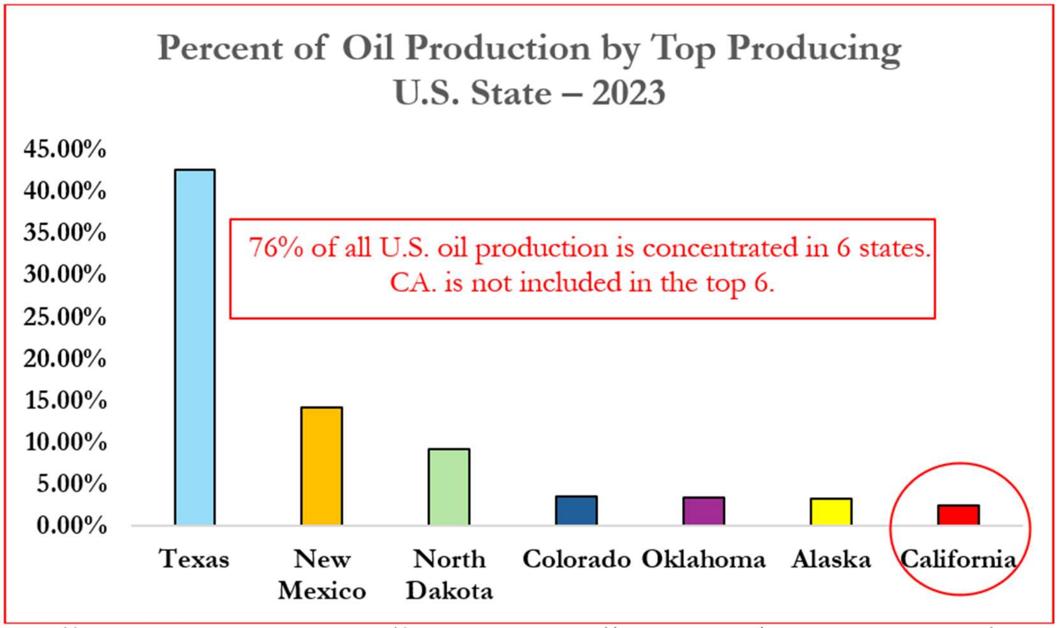
54 *Statewide_LAEDC_2025_factsheet-1.pdf | Powered by Box*. (2025). Box.com. https://wspa.app.box.com/s/2v30dlvt0fbez09irhav001rw19tfh48

55 *Oil & Gas In California – Los Angeles County Economic Development Corporation*. (2025, March 16). Laedc.org. https://laedc.org/research/reports/oil-gas-in-california/

56 *Fuel Taxes Statistics & Reports*. (n.d.). Www.cdtfa.ca.gov. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts.htm

57 *California State Energy Profile. California Profile*. (n.d.). https://www.eia.gov/state/print.php?sid=CA#89

Figure 8



(Source: Top 11 Oil-Producing States in 2023, ROBERT RAPIER, as cited in https://oilandgaspress.com/top-11-u-s-oil-producing-states/. See also, https://www.investopedia.com/financial-edge/0511/top-6-oil-producing-states.aspx#citation-21)

iii. Production

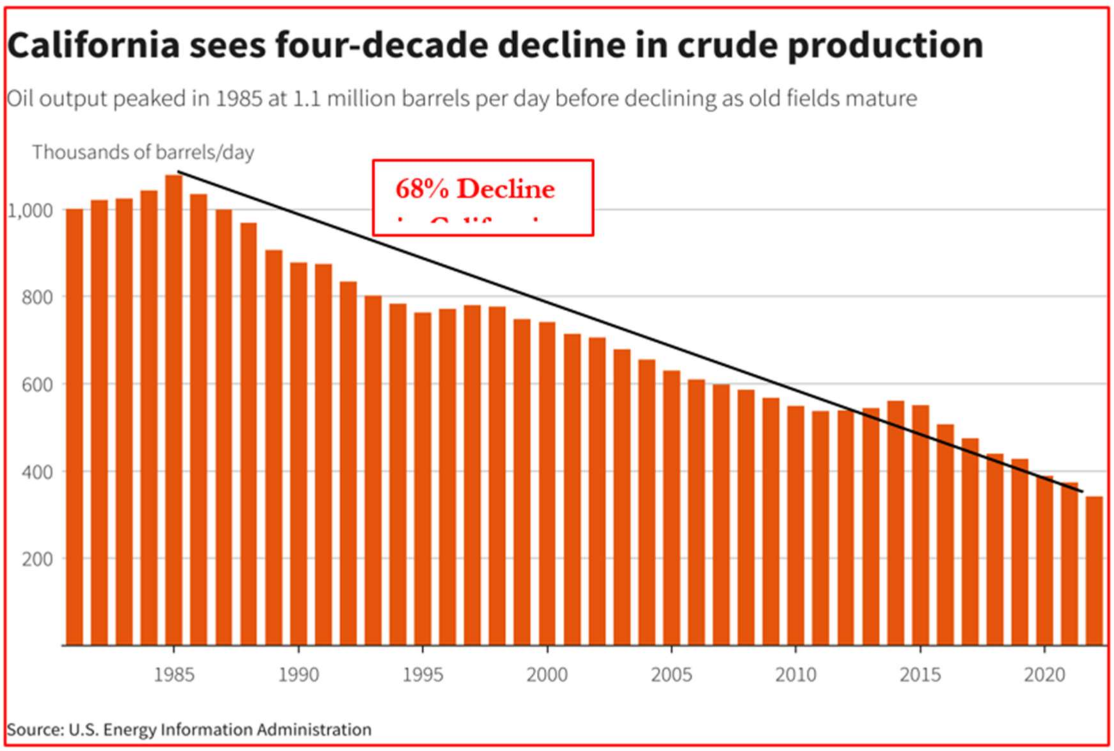
37. Once a global leader and ranking fourth in the world in oil production, today, California accounts for only around 2.5% to 2.7% of all U.S. crude production and is producing only 23.7% of its own in-state needs. California's oil production has consistently fallen since 1992. In 1992, California produced 320,888,000 barrels of oil.[58] In contrast, in 2022, California produced 124,727,000 million barrels of oil or only 39% of 1992 production. On a comparative basis for the 1990 to 2022 period, California's oil field production declined while overall U.S. oil field production grew. In 2012, the Golden State's in-state oil production was 197 million barrels a day, and California's population was 37.5 million. However, by 2022/23, with California's population at 38.95 million, in-state oil production

[58] California Energy Commission. (n.d.-a). *Annual oil supply sources to California refineries*. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/annual-oil-supply-sources-california

had fallen by 35% to 127 million barrels. Meanwhile, California imports of non-U.S. foreign oil grew by 1,102% from its historic low in 1991 of 31 million barrels to 369 million barrels its peak high in 2018.[59]

38. Since 1990, while overall U.S. field production has increased 66%, California's field production declined 61%, and 68% decline from its peak production in 1985. From 2018, California's field production has declined 26.4%. Since 1982, California's ability to meet its demand for petroleum through in-state production has fallen from over 68% internally sourced to about 21% in 2023.

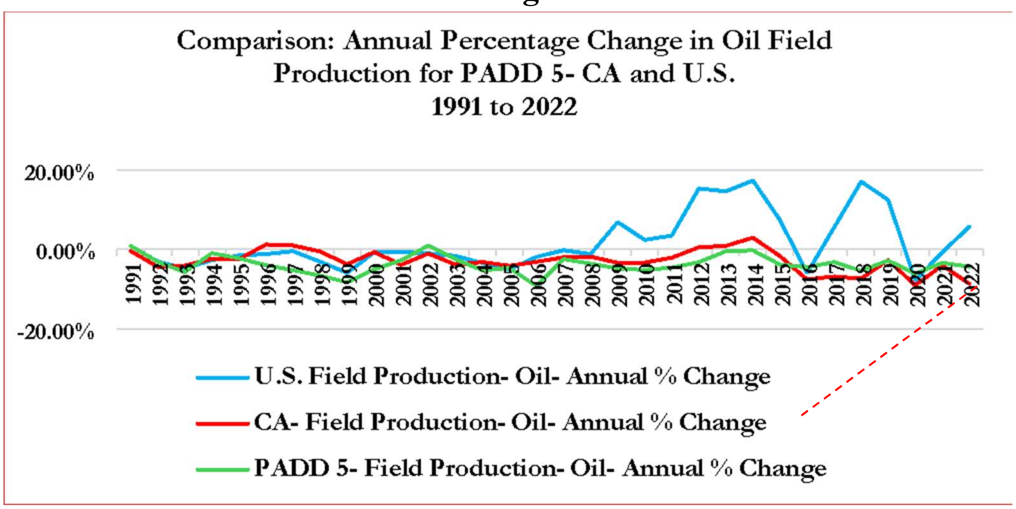
Figure 9



[59] Based on CEC data.

39. California's oil fields, production, and refineries are assigned to PADD Region 5.[60] The Petroleum Administration Defense Districts, or "PADDs," were established during World War II as a means of managing and allocating petroleum resources and production to the war effort. The structure worked so well that it has been retained for reporting purposes today. The PADD 5 region includes Alaska, Arizona, California, Hawaii, Oregon, and Washington. On an annual percentage change basis, for the 1991 to 2022 period, while U.S. oil field production increased and overall PADD 5 production moderated, California production fell.

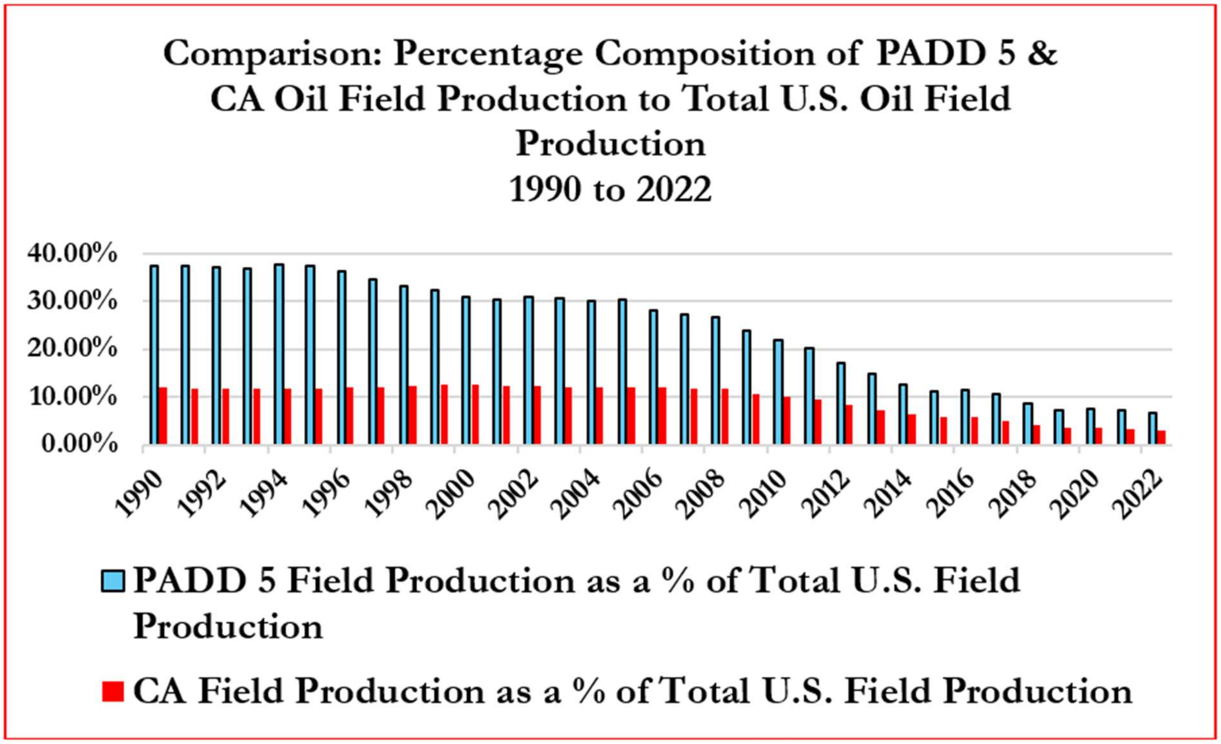
Figure 10



40. Notwithstanding the increase in California's population, GDP, and motor vehicle registrations, for the 1990 to 2022 period, PADD 5 and **California oil field production as a percentage of total U.S. production has declined due to decreased in-state field production**.

[60] Petroleum Administration Defense District. The PADDs were created in 1942 by Presidential Executive Order during WW-II as a method for managing petroleum resources. It is currently used to collect data and for data analysis.

Figure 11



(Source: EIA)

41. California refineries use oil to produce a slightly different product mix and yields on a barrel-to-barrel basis compared to a "typical" barrel of oil products. Below is a chart comparing the "typical" barrel product or "slate" mix of California petroleum products to typical U.S. refineries for California in 2024.

Figure 12[61]

Comparison of Product Types Per Barrel-CA. to U.S.		
Product Type	**Typical U.S. Product Types**	**California Product Types**
CA. CARB Gasoline	0.00%	42.40%
Aviation (Jet) Fuel	9.00%	15.30%
CA CARB Diesel Fuel	25.00%	10.00%
Conventional Gasoline	45.00%	5.20%
EPA Diesel Fuel	0.00%	5.80%
Other RBOB	0.00%	2.40%
Other Diesel	0.00%	0.20%
Total All Fuels	**79.00%**	**81.30%**
All Other Products	21%	18.70%
Grand Total:	**100.00%**	**100.00%**

(Source: CDTFA_CEC joint report 2024 review of the gasoline in ... (n.d.-b)

42. Significantly, the addition of Sable oil production from its three offshore platforms and the use of its existing Las Flores Pipeline System will change the supply dynamics in the State by creating not only more viable and more cost effective alternatives to non-U.S. foreign oil supplies, but will also work to help stabilize consumer gasoline prices by reducing the uncertainties and insecurities related to the crude oil supplies necessary to support California's refineries in their production of combustible fuels such as gasoline, diesel and aviation, as well as asphalt and distillates used in the manufacturing of mobile phones, medical devices, and other essential products.

iv. Movement & Transportation

43. Petroleum products, such as oil and gasoline, are moved from point to point using various transportation methods, including marine vessels, barges, pipelines, rail tankers, and truck tankers. The movement of gasoline and oil is supported by storage tanks for short-term product storage.

[61] CDTFA_CEC joint report 2024 review of the gasoline in ... (n.d.-b). https://seuc.senate.ca.gov/sites/seuc.senate.ca.gov/files/cdtfa_cec_joint_report_2024_review_of_the_gasoline_in_california_and_relate.pdf

44. **California has no inbound pipelines** for petroleum or gasoline. However, the State has an extensive in-state (intrastate) network of pipelines for moving oil and gasoline from ports to refineries to distribution points (racks), as well as end-users such as airports. **California pipelines carry fuels to 60 distribution points within the state**. Proprietary pipelines are owned and operated by companies such as Crimson and PBF Logistics and were owned by Chevron and ExxonMobil. The sole private common carrier in California is Kinder Morgan.[62] Kinder Morgan owns, has an interest in, and operates over 79,000 miles of pipelines and 139 terminals throughout the U.S.[63] For perspective, according to the U.S. Department of Transportation, the U.S. has over 2.6 million miles of installed petroleum and petroleum-related pipelines.[64]

45. **California has two major outbound pipelines** to supply gasoline to Nevada and Arizona. California's pipeline network is composed of common carrier arteries that transport products from multiple producers and proprietary pipelines.

46. According to the **U.S. Department of Transportation, pipelines are the safest method to transport petroleum products**.[65] A modern pipeline integrates advanced safety technologies with continuous operations to constantly monitor safety and environmental impacts. In the U.S., pipelines and pipeline operations are highly regulated and fall under the purview of various federal, state, and local agencies, including the Pipeline and Hazardous Materials Safety Administration. In California, the California Department of Conservation's Geologic Energy Management Division (CalGEM) and the California Office of the State Fire

---

[62] Schremp, G. (2016). *PADD 5 & California Transportation Fuel Overview Western Regional Emergency Fuel Coordination Meeting California Energy Commission Sacramento, CA*. https://www.naseo.org/Data/Sites/1/schremp-1.pdf

[63] *Home - Kinder Morgan*. (n.d.). Www.kindermorgan.com. https://www.kindermorgan.com

[64] *General Pipeline FAQs*. (n.d.). PHMSA. https://www.phmsa.dot.gov/faqs/general-pipeline-faqs

[65] *General Pipeline FAQs*. (n.d.). PHMSA. https://www.phmsa.dot.gov/faqs/general-pipeline-faqs

Marshal (OSFM) oversee oil and gas pipelines.[66] **California has the strictest standards for oil and gasoline pipeline construction, testing, and maintenance in the world**.

47. Since California has no inbound pipelines and its in-state production has fallen considerably, nearly 100% of California's non-U.S. sourced imported oil is delivered to its refineries via maritime vessels, which are significant contributors to GHG emissions.[67] For 2023, California received 61% of its crude oil stocks from foreign sources and 16% from Alaska. Oil imports from these sources are delivered to California using maritime oil tanker vessels (limited barge).[68] Tankers that move oil among and between U.S. ports must comply with the Jones Act.[69] Passed in 1920 as the Merchant Marine Act of 1920, the Jones Act, as amended in 2006, prohibits foreign-flagged vessels from carrying cargo, including petroleum products between U.S. maritime ports in the contiguous states. Under the Jones Act, cargo, including crude oil, must be transported on U.S. flagged ships, built in the U.S. and crewed U.S. crew members. As of 2024, there are only 55 to 58 U.S. tankers that are compliant with the Jones Act and the majority, if not all, are deployed between the Gulf Coast and East Coast markets. The lack of available Jones Act compliant tankers compromises California's ability to move crude from other U.S. sources and strengthens the need for Sable production and the use of the Las Flores Pipeline System.

---

[66] California Department of Conservation. (n.d.). *Pipelines and facilities*. https://www.conservation.ca.gov/calgem/for_operators/Pages/Facilities.aspx#:~:text=Generally%2C%20CalGEM%20regulates%20all%20pipelines,used%20for%20transportation%20to%20refineries.

[67] California Energy Commission. (2022). *2022-07_Petroleum_Watch*. California Energy Commission. https://www.energy.ca.gov/media/7138

[68] Commission, C. E. (n.d.). *Foreign Sources of Crude Oil Imports to California 2020*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/foreign-sources-crude-oil-imports

[69] Section 27 of the Merchant Marine Act of 1920 (P.L. 66-261). See, also: https://crsreports.congress.gov/product/pdf/R/R45725

48. California has only a minimal amount (less than 1% in 2015) of inbound oil transported using rail tankers.[70] [71] In 2024, California received no inbound crude from Canada via rail but did import 468,000 barrels from North Dakota by rail tanker.[72] In the U.S., a DOT-117 certified rail tanker can hold up to 286,000 gallons or 6,809 barrels of product and must be designated with NA1993 identification.[73] [74] With respect to rail transport, one of the controlling factors is the capacity of the rail tracks and routes. Rail tracks are rated for speed and weight and, therefore, have restrictions. Similar restrictions are associated with tunnels, bridges, curves, incline grades, declines, and urban areas.

49. **California relies extensively on over-the-road tanker trucks for the local shipping** of finished gasoline products from refineries to distributors (racks) and onward for delivery to retail gasoline stations. In 2015, tanker trucks averaged approximately 4,980 deliveries per day, representing 39.84 million gallons of gasoline.[75] In California, **94% of all trucks are fueled by either diesel (67%) or gasoline (25%)**.[76]

---

[70] Schremp, G. & California Energy Commission. (2016). California transportation fuel overview. In *Western Regional Emergency Fuel Coordination Meeting*. https://www.naseo.org/Data/Sites/1/schremp-1.pdf

[71] Commission, C. E. (n.d.). *Foreign Sources of Crude Oil Imports to California 2020*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/foreign-sources-crude-oil-imports

[72] California Energy Commission. (2024). *Crude Oil Imports By Rail*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/annual-oil-supply-sources-california/crude

[73] *More Rail Tank Cars Meet DOT-117 Safety Standards in 2022 | Bureau of Transportation Statistics*. (2022). Bts.gov. https://www.bts.gov/newsroom/more-rail-tank-cars-meet-dot-117-safety-standards-2022

[74] *Economics of Rail versus Pipeline*. (n.d.-b). Welcome to Altex Energy. https://www.altex-energy.com/economics-of-rail-versus-pipeline/#1501828266955-2913a69d-c276

[75] Crockett, & Schremp, G. (2015). *California Transportation of Petroleum Second Northern California Refinery Safety Forum*. https://calepa.ca.gov/wp-content/uploads/sites/6/2016/10/Refinery-Documents-2015yr-Petroleum.pdf

[76] California. (n.d.). *Large Entity Fleet Reporting STATEWIDE AGGREGATED DATA*. Retrieved February 23, 2025, from https://ww2.arb.ca.gov/sites/default/files/2022-02/Large_Entity_Reporting_Aggregated_Data_ADA.pdf

50. Two factors combine to make oil and fuel production a critical concern in California. First, California is virtually completely dependent on foreign, non-U.S.-sourced oil to produce its fuels. Second, California has had restrictions and is losing refinery capacity to produce fuels. The combination of these two factors is potentially fatal to the State's economic vitality, growth, and long-term security. Significantly, any disruption of this very tight and delicate balance of supply and demand could have debilitating consequences for the State.

v. California Consumption

51. Gasoline, diesel, and aviation fuels are made from crude oil. California is the 2nd largest consumer of petroleum and the largest consumer of aviation fuel in the U.S.[77] In 2023, Californians consumed over 500 million barrels of oil (1.8 million per day), 13.119 billion gallons of gasoline, 3.6 billion gallons of diesel fuel, and over 216 million gallons of aviation fuel, based on CEC and CDTFA revenue data. [78] [79] [80]

52. The largest consumer of crude oil in California is gasoline production. Diesel fuel consumption is the second largest and represents about 17% of all crude oil consumption in the Golden State.[81] Californians consume between **30 to 33 million gallons of gasoline a day and around 9.9 million gallons a day of diesel fuels**. According to the CEC, 97% of all

[77] U.S. EIA, Crude Oil Production, Annual, Thousand Barrels, 2023.

[78] California Department of Tax and Fee Administration. (n.d.-b). Fuel Taxes Division Statistics & Reports – 2010. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts10.htm

[79] California's Refinery Capacity Stretched to the Limit | California Policy Center. (2025, April 11). California Policy Center |. https://californiapolicycenter.org/californias-refinery-capacity-stretched-to-the-limit/

[80] Fuel Taxes Statistics & Reports. (n.d.). Www.cdtfa.ca.gov. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts.htm

[81] Commission, C. E. (n.d.). *Diesel Fuel Data, Facts, and Statistics*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/transportation-energy/diesel-fuel-data-facts-and-statistics

gasoline in California is consumed by automobiles, SUVs, and light-duty trucks.[82] The CEC further notes that "Nearly all heavy-duty trucks, delivery vehicles, buses, trains, ships, boats and barges, farm, construction and heavy-duty military vehicles and equipment have diesel engines. **Diesel is the fuel of choice because it has 12 percent more energy per gallon** than gasoline and has fuel properties that prolong engine life, making it ideal for heavy-duty vehicle applications."[83]

53. In general, long-term oil and gasoline consumption demonstrate relative inelasticity to price. That is, price increases do not have a correspondingly equal impact on consumption as consumers and incomes adjust to higher prices over the long term. However, studies do indicate the presence of elasticity in the short-term, particularly in California.[84] The consequence of oil, gasoline, and diesel fuel price increases, as well as aviation fuels, generally results in a change in consumer behavior in other expenditure areas; that is, consumers may reduce spending on entertainment, for example, in order to compensate for higher energy costs.

54. **Oil and gasoline consumption in California has not declined significantly over a twenty-five-year period**. Despite nearly a 100% improvement in miles per gallon due to engine and drive train efficiencies since 1975, and irrespective of California's considerable efforts to encourage and force (and 2035 mandate) the adoption of EVs and Zero Emissions Vehicles (ZEVs), California's demand for oil and gasoline have moderated only slightly over the 2001 to 2024 period. Furthermore, 2025 EV and ZEV adoption rates are significantly lower than CARB estimates and, according to recent sales figures, have slowed

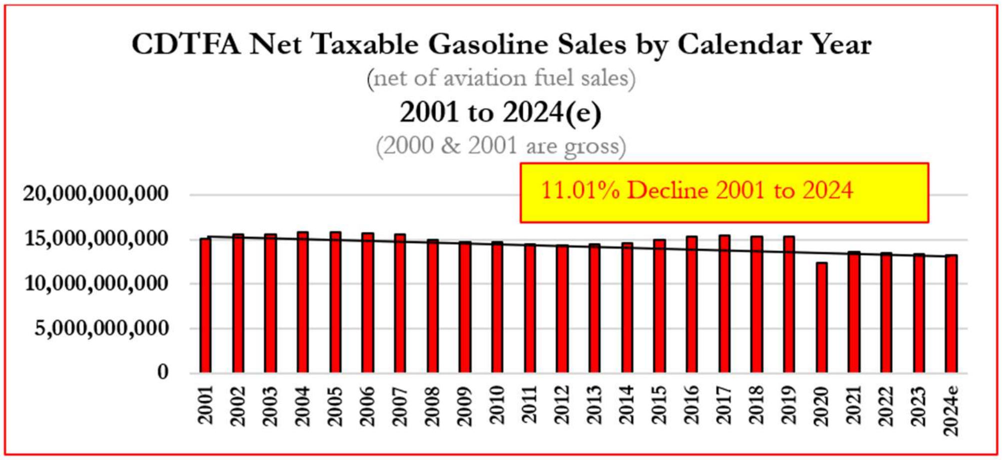
[82] Commission, C. E. (n.d.). *California Gasoline Data, Facts, and Statistics*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/transportation-energy/california-gasoline-data-facts-and-statistics

[83] Commission, C. E. (n.d.). *Diesel Fuel Data, Facts, and Statistics*. California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/transportation-energy/diesel-fuel-data-facts-and-statistics

[84] Colina, Armando R., et al. "Estimates of Gasoline Demand Elasticity Using California Refinery Outages." SSRN Electronic Journal, 2023, https://doi.org/10.2139/ssrn.4629611.

considerably.[85] From 2001 to 2024, overall, CDTFA reported gasoline sales had fallen 11.12 % or less than one-half of one percent per year.[86]

Figure 13



(Source: https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts10.htm)

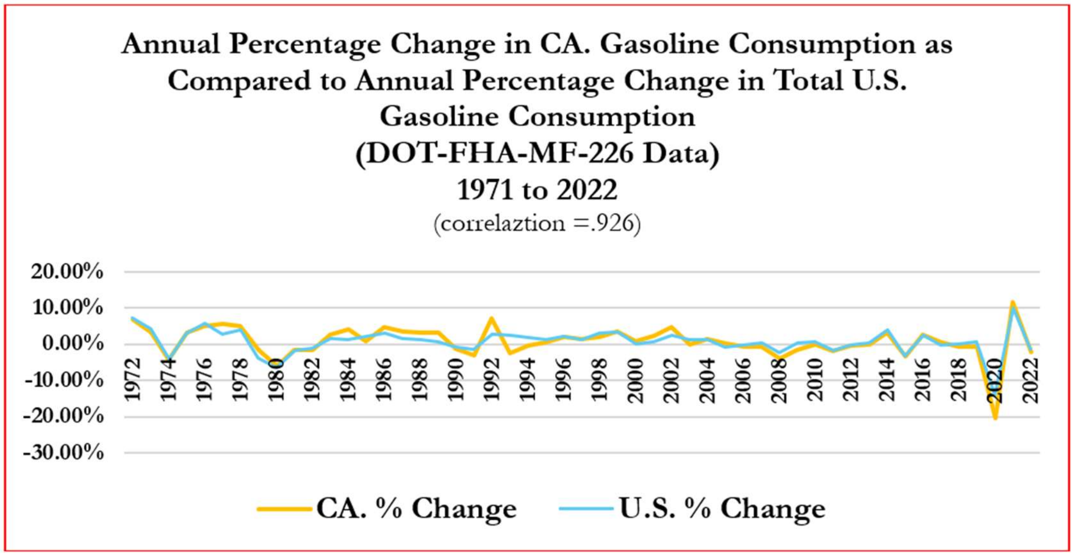
55. The annual percentage change in CDTFA gasoline sales is relatively consistent. It shows only a modest annual variance of -.46% and is highly correlated to the annual percentage change in overall U.S. gasoline consumption.

---

[85] "New ZEV Sales in California." *Www.energy.ca.gov*, www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/new-zev.

[86] *Fuel Taxes Division Statistics & Reports – 2020*. (2020). Ca.gov. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts20.htm

Figure 14



(Source: https://www.fhwa.dot.gov/policyinformation/statistics/2022/mf226.cfm)

56. Given California's economic profile and growth rate, there is no indication that the demand for crude oil, gasoline, diesel fuels, and aviation fuels will decline significantly over the forthcoming ten-year period**.** Declines in fossil fuel usage are anticipated as alternative fuels are perfected and scaled, but various agencies and researchers expect the demand for oil to peak sometime between 2035 and 2055.[87] Notwithstanding the inevitable and future peak in fossil fuel production, crude oil is and will remain a vital component of any economy as it is used in so many other applications, such as asphalt and concrete.

vi. California Imports

57. California is the most dependent of all fifty states on foreign, non-U.S. oil as a source for refineries to produce gasoline, diesel, and aviation fuels. Since the 1980s, California's in-state oil production has fallen, and its reliance on foreign-sourced oil increased. By 2023, California's in-state oil production was only able to supply around 23% of its needs, and its dependency on foreign-sourced oil grew by over 850%.

[87] Kimani, Alex. "IEA Predicts End to Oil & Gas Demand Growth before 2030." *OilPrice.com*, 18 Oct. 2024, oilprice.com/Energy/Energy-General/IEA-Predicts-End-to-Oil-Gas-Demand-Growth-Before-2030.html.

58. As California's in-state oil field production declined, the Golden State turned to foreign petrostates to meet its in-state crude demands.[88] [89] For 2023, **60.7% of California's oil was imported from foreign sources, including the petrostates of Iraq (21.7%) and Saudi Arabia (15.7%)**. South America's Brazil and Ecuador represented the third and fourth largest sources of California import sources at 15.1% and 14.6%, respectively. Collectively, and based on CEC data, the three largest sources (Iraq, Saudi Arabia, and Brazil) represented 52.4% of all California foreign imports.[90] Middle Eastern oil from OPEC members Saudi Arabia, Iraq, and the U.A.E., in aggregate, represented 39.25% of all California oil imports for 2023.

59. According to various independent estimates, **California ranks #1 in payments to foreign sources of oil** and pays more than $61.8 million per day, or $22.5 billion annually, based on Brent market prices, or $54.41 million a day, or $19.8 billion annually, based on WTI market prices, to foreign countries such as Iraq, U.A.E., and Saudi Arabia, and others for its oil imports.[91]

---

[88] Fox News. (2015, December 21). *Shale oil deposit a possible boon to struggling California, but state wary, enviros opposed*. https://www.foxnews.com/politics/shale-oil-deposit-a-possible-boon-to-struggling-california-but-state-wary-enviros-opposed

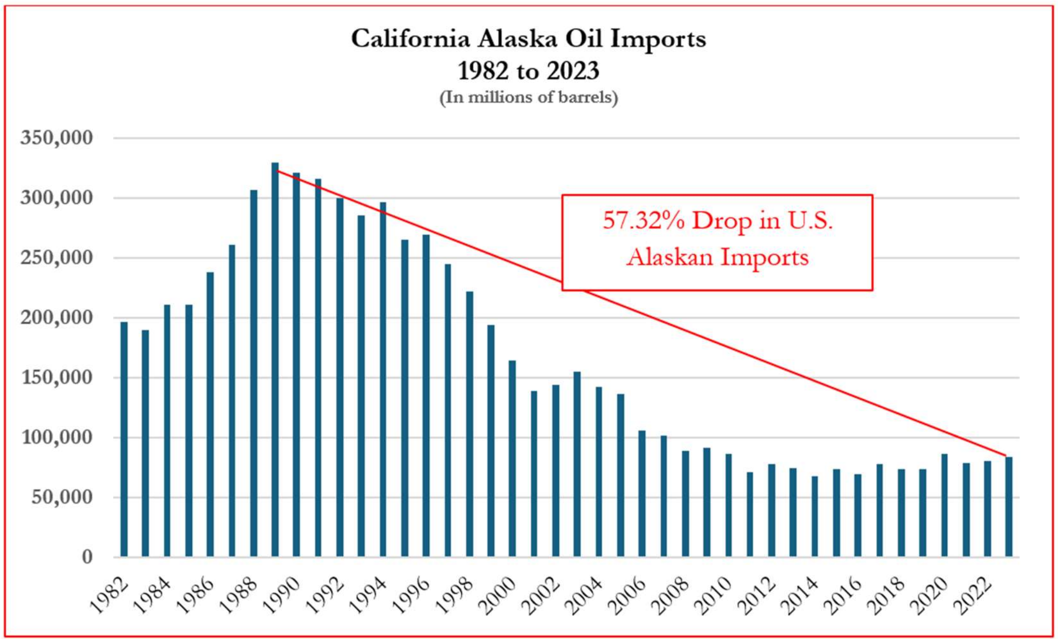
[89] Jones, J. (2024, March). *States With the Most Oil Reserves [2024] - Construction Coverage*. Construction Coverage. https://constructioncoverage.com/research/states-with-the-most-oil-reserves

[90] California Energy Commission. (n.d.-h). *Foreign sources of crude oil imports to California*. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/foreign-sources-crude-oil-imports

[91] Based on WTI and Brent crude prices as of 3/14/25, and CA. imports are reported by CEC. See also, Ed, C. (2018, October 9). *California ranks #1 in sending dollars abroad for Energy*. https://www.cfact.org/2018/10/09/california-ranks-1-in-sending-dollars-abroad-for-energy/ . See also, *FACTS - Californians for energy independence*. (2023, July 31). Californians for Energy Independence.
https://www.energyindependenceca.com/facts/#:~:text=California%20now%20imports%2075%25%20of,use%2C%20mostly%20from%20foreign%20countries.&text=California%20spends%20$25%20Billion%20dollars,to%20meet%20our%20energy%20needs.

60. In 1982, California produced 61% of its oil needs in the State.[92] Commencing in the mid-1990s, as California's imports of domestically produced oil from Alaska and in-state oil production began a long-term decline, its need for foreign-produced oil began to accelerate. While imports of non-U.S. domestically sourced oil from OPEC and other states increased by 850%, California imports of U.S. domestically produced oil from Alaska plummeted by 57.32%.[93]

Figure 15



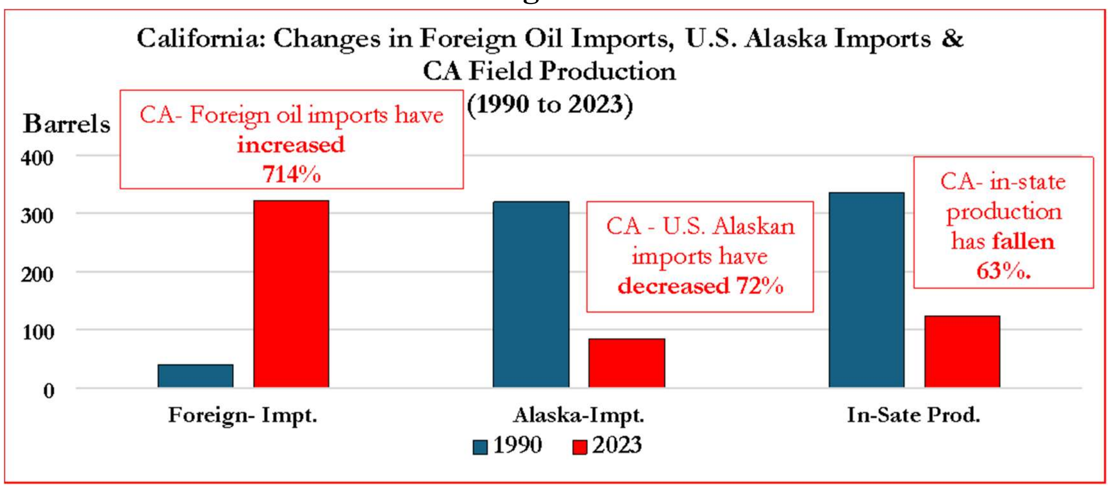
(Source: https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/annual-oil-supply-sources-california)

[92] California Energy Commission. (n.d.-a). *Annual oil supply sources to California refineries*. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/annual-oil-supply-sources-california

[93] Alaska North Slope oil field production declined but accounted for 15% of California's oil in 2021. Today, the Alaskan Pipeline operates at 20-25% of its original capacity due to lower field production. However, both field production and pipeline capacity utilization are expected to increase in 2025. See, https://www.californiaenergyatlas.com/crude-oil

61. While imports from foreign sources increased, domestically sourced 'imports' from other U.S. petroleum-producing states, Alaska and California's in-state production have declined.

Figure 16



(Source: CEC)

62. While imports of non-U.S. domestically sourced oil from OPEC and other states increased by 857%, California imports of U.S. domestically produced oil, predominantly supplied from Alaska, plummeted by 57.32%.[94]

[94] Alaska North Slope oil field production declined but accounted for 15% of California's oil in 2021. Today, the Alaskan Pipeline operates at 20-25% of its original capacity due to lower field production. However, both field production and pipeline capacity utilization are expected to increase in 2025. See, https://www.californiaenergyatlas.com/crude-oil

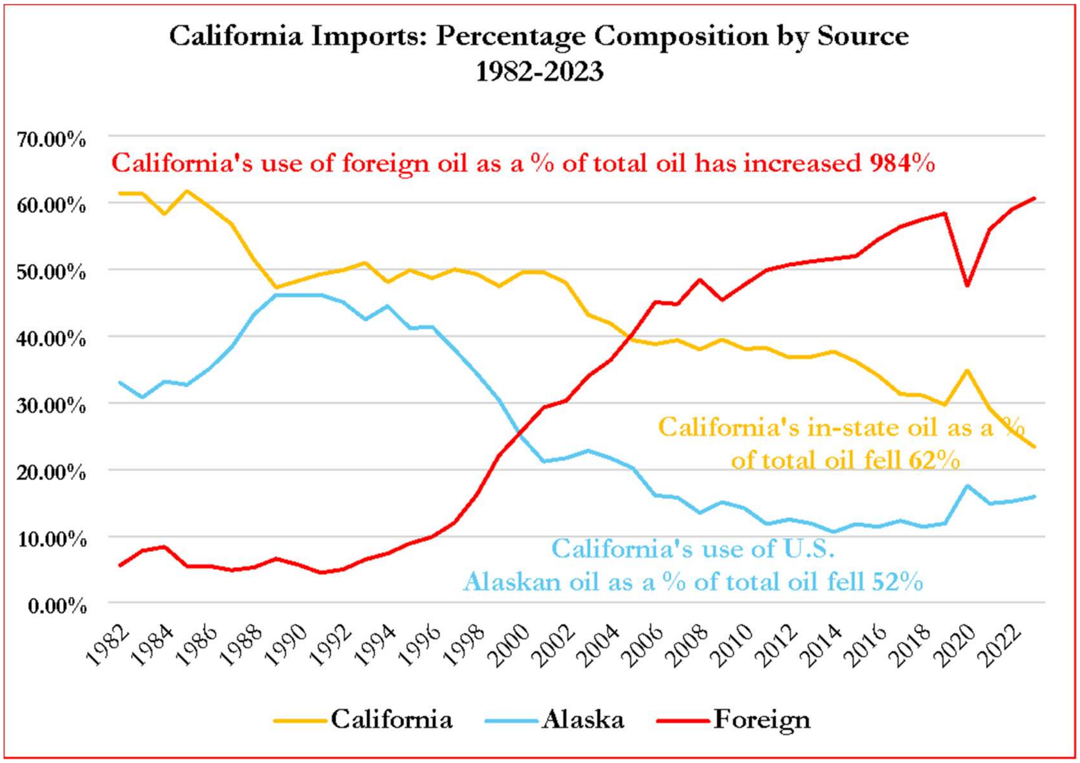


Figure 17

(Source, CEC, EIA, and Author)

63. Compared to all U.S. oil imports, for 2024, California has a significantly greater dependency on and a higher percentage of non-U.S. foreign oil from petrostates such as Iraq, as well as high dependency on South America's Brazil and Ecuador than the overall U.S. Since 1982, California's reliance on foreign oil imports has increased by 857%, or 20 times greater than that of the overall U.S.' importing of foreign oil.[95]

64. **No state in the U.S. imports more foreign-sourced oil for its use than California**. In 2023, California imported 321.153 million barrels of oil from non-U.S. sources. Since 1982, California's imports of foreign oil have increased by 857%. In 2024, California imports increased slightly to 321.831 million barrels of oil, or .21%. In 2024, as

[95] Alternative Fuels Data Center: Maps and Data - U.S. Production, Consumption, and Trade of Petroleum Products. (n.d.). Afdc.energy.gov. https://afdc.energy.gov/data/10324

U.S. imports of foreign oil hit a thirty-year low, California imports of crude came within 13% of its thirty-year high (2018).[96]

65. In 2024, California's mix of non-U.S. foreign imports changed due to the emergence of Guyana filed production. Iraq, which provided 68,406 barrels of oil, composed 21.26% of its non-U.S. oil imports. Brazilian oil imports increased to 20.41%, and as production scaled in Guyana, imports from that South American country increased exports to California to 50,840 barrels or 15.80% of the total 321,831 barrels of non-U.S. imported oil.[97] Additionally, throughout its history, California has also imported oil from Russia, Angola, Oman, and other national providers.[98]

66. California's oil dependency on imports from various petrostates, such as Iraq and Saudi Arabia, as well as various other Middle Eastern sources, have both intended and unintended economic consequences and directly and indirectly support the sourcing countries' economies, governing policies and structures, political agendas, and societal initiatives. Summarized in the Figure below are some pertinent social, political, and human freedom rankings for various sources such as Transparency International and Global Finance of California crude oil imports.[99] Iraq, which is California's largest provider of foreign in

---

[96] Roberts, K. (2024, August 19). *2024 U.S. oil imports from Middle East hit new record low*. Forbes. https://www.forbes.com/sites/kenroberts/2024/08/16/2024-us-oil-imports-from-middle-east-hit-new-record-low/. See also, EIA and CEC import data.

[97] California Energy Commission. (n.d.-d). *Foreign sources of crude oil imports to California*. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/foreign-sources-crude-oil-imports

[98] *California 2019 crude average carbon intensity up*. (2019). Green Car Congress. https://www.greencarcongress.com/2020/06/20200616-carbci.html

[99] Sources include Transparency International. (2024, September 12). 2023 *Corruption Perceptions Index: Explore the results*. Transparency.org. https://www.transparency.org/en/cpi/2023; Vásquez, I., Mcmahon, F., Murphy, R., & Schneider, G. (2023). *HUMAN FREEDOM INDEX 2023 A Global Measurement of Personal, Civil, and Economic Freedom*. https://www.cato.org/sites/cato.org/files/2023-12/human-freedom-index-2023-full-revised.pdf; *Age of conflict*. (n.d.). https://pages.eiu.com/rs/753-RIQ-438/images/Democracy-Index-2023-Final-report.pdf?version=0; Ventura, L. (2024, October 20). *Poorest Countries in the world 2024*. Global Finance Magazine. https://gfmag.com/data/economic-data/poorest-country-in-the-world/; *Human*

2023, is ranked 27th out of 179 as a "Fragile/Failed State Index" by the Fund for Peace. For perspective, North Korea and Rwanda rank "better." The U.S. is ranked 141st.[100]

Figure 18

Comparison: Selected Rankings for Social, Economic & Corruption for California Oil Imports (2023/2024)					
	Iraq	**Saudia Arabia**	**Brazil**	**Ecuador**	**United States**
Percent of California Total Imports	21.70%	15.70%	15.10%	14.60%	NA
Corruption Perception Ranking	154	53	104	115	24
Human Freedom Ranking	156	157	70	72	17
Media/Press Freedom Ranking	169	166	82	110	55
Democracy Ranking	128	150	51	85	29
Economic Freedom Ranking/Score	Not Ranked	61.9	53.2	55	70.1
Poorest County Ranking	71	173	107	79	182
Government Integrity	18.3	43.9	36.9	34.9	76.4

Figure 19

FRAGILE STATES INDEX RANKING Selected CA Sources of Foreign Imports	
California Oil Source	**Overall Ranking Out of 179**
Iraq	27
Brazil	71
Ecuador	87
Saudi Arabia	100
U.S.A.	141
Note: Lower number = more unfavorable.	

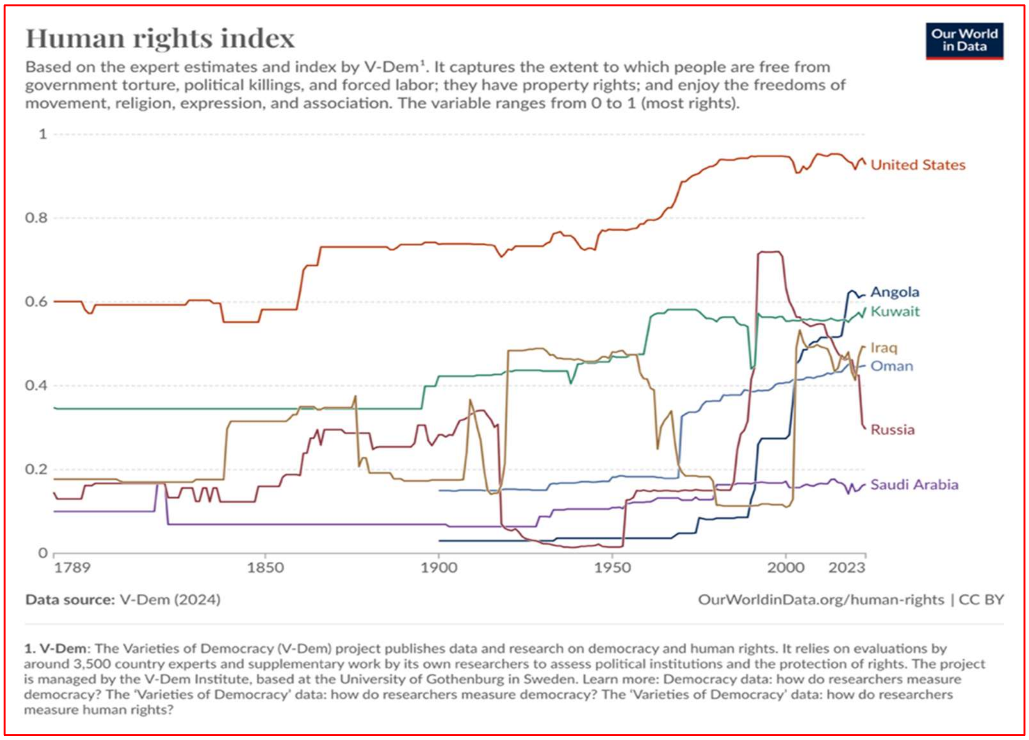
(Source: https://fragilestatesindex.org/excel/)

67. California's sources of foreign oil rank considerably lower in terms of human rights compared to domestically available sources from the U.S., including California.

rights index. (2024, March 7). Our World in Data. https://ourworldindata.org/grapher/human-rights-index-vdem?tab=chart&country=BRA~ECU~IRQ~SAU~USA; and The Heritage Foundation. (n.d.). *Index of Economic Freedom: All Country Scores | The Heritage Foundation*. Index of Economic Freedom | the Heritage Foundation. https://www.heritage.org/index/pages/all-country-scores.

[100] Energyskeptic. (n.d.). *Peak everything, overshoot, & collapse - preservation of knowledge*. Peak Everything, Overshoot, & Collapse - Preservation of Knowledge. https://energyskeptic.com/

Figure 20



D. Crude Oil Pricing

i. Commodity Pricing & Volatility

68. Crude oil is a commodity, and the price of crude oil is highly volatile and subject to dramatic swings and shifts, which, in turn, influence retail gasoline and aviation and diesel fuel prices. Crude oil prices swing wildly by the day, hour, and even the minute and, as such, are notoriously difficult to predict. Any major geopolitical event, weather disruption, labor situation, maritime tanker issues, etc., influence the price of oil.

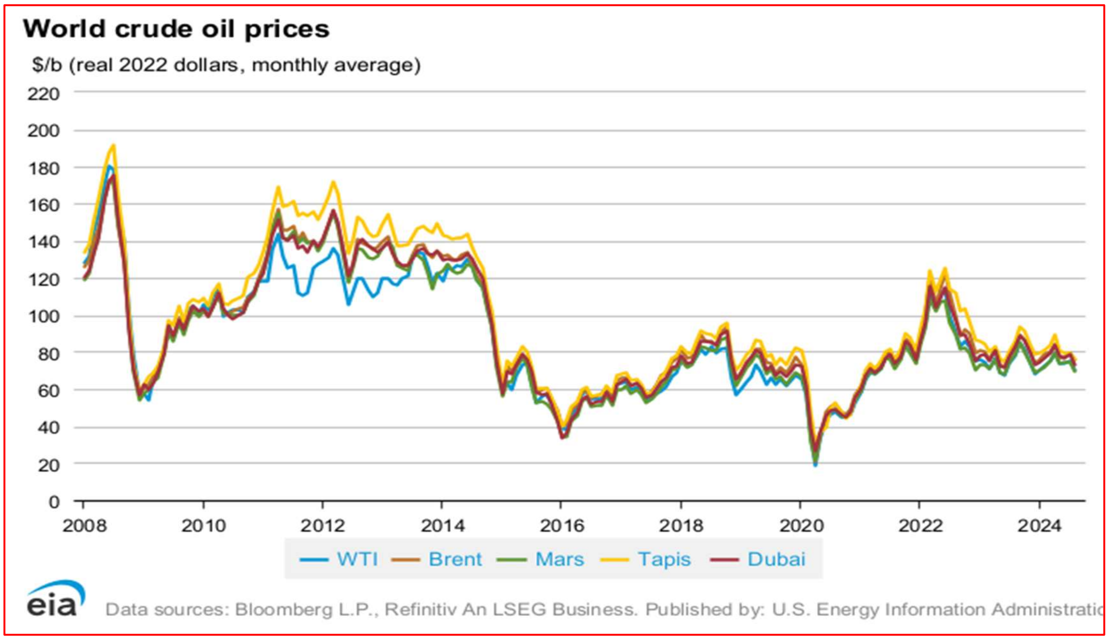
69. As a global commodity, crude oil prices are set and traded on various international markets. Oil and gasoline pricing are very complex and subject to wide variations from day to day, even by the hour to hour, and in some instances, by the minute. The price of crude oil is primarily driven by the basic economic laws of supply and demand. When demand is strong and supply is low, the prices of oil, diesel, aviation fuels, and gasoline escalate.

70. As petroleum is a global commodity, its **pricing is subject to extreme volatility**. Geopolitical, domestic, political, and regulatory actions conflate the basic market powers of supply and demand. Five factors influence the spot price of oil: **1-** supply (production), **2-** demand (consumption), **3-** geo-political events, **4-** national and local government policies and regulations, and **5-** trading/financial markets. Notably, any significant disturbance to any of these influencing factors will have an impact on the price of oil and, ultimately, the price of diesel and aviation fuels, as well as retail gasoline prices.

71. Oil is traded using long-term contracts and spot pricing in multiple markets, with the New York Mercantile (NYMEX) and Intercontinental Exchange (ICE) being predominant. Gasoline is also traded on global markets and in California on spot markets in San Francisco and Los Angeles. The trading prices of various oil types and grades are highly correlated and generally move in the same direction with similar degrees in magnitude of movement. Future oil prices are speculative and can fluctuate wildly. For example, on April 20, 2020, the price of oil fell 306% from its May 2020 futures crude contract price to a negative price of $37.63 a barrel on the New York Mercantile Exchange.[101] Technically, this type of inversion between current and future prices implies that the seller would have to pay the buyer to purchase the seller's oil contract. Under those circumstances, producers have little incentive to produce more products. Illustrated in the chart below are the various crude oil prices for various grades for the 2008 to 2024 period. As indicated, oil prices in various markets tend to move in correlation with one another.

[101] Saefong, M. P. (2021, April 19). Oil prices went negative a year ago: Here's what traders have learned since. MarketWatch. https://www.marketwatch.com/story/oil-prices-went-negative-a-year-ago-heres-what-traders-have-learned-since-11618863839

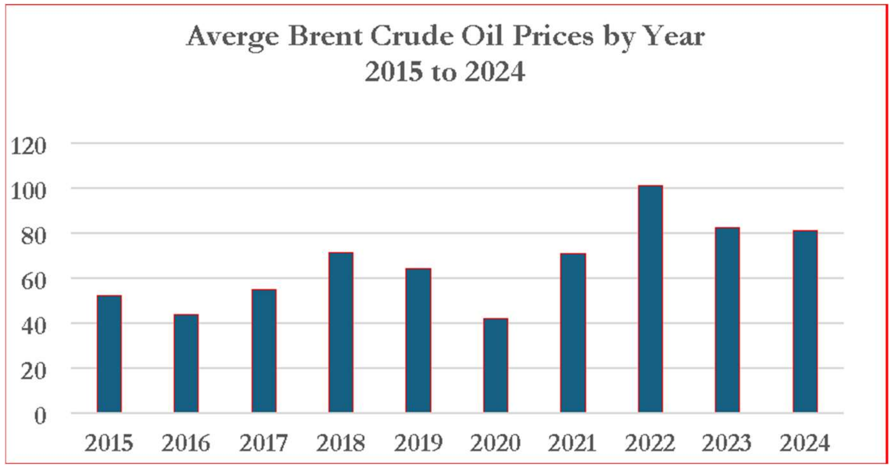
Figure 21



(Source: https://www.eia.gov/finance/markets/crudeoil/spot_prices.php#:~:text=Crude%20oil%20is%20traded%20in,that%20are%20lower%20in%20quality)

72. As indicated, the price of crude oil swings radically from period to period. For example, in the mid-2015 period, the WTI price of crude, which is typically a bit lower than Brent, was $108 a barrel. Within about 7 months, the WTI price dropped 70% to $32 a barrel. In 2019, the average price of Brent crude was $64.30 a barrel. However, with the onset of COVID, the average price of Brent fell by almost 35% in 2020 and shot back up 141% in 2022.

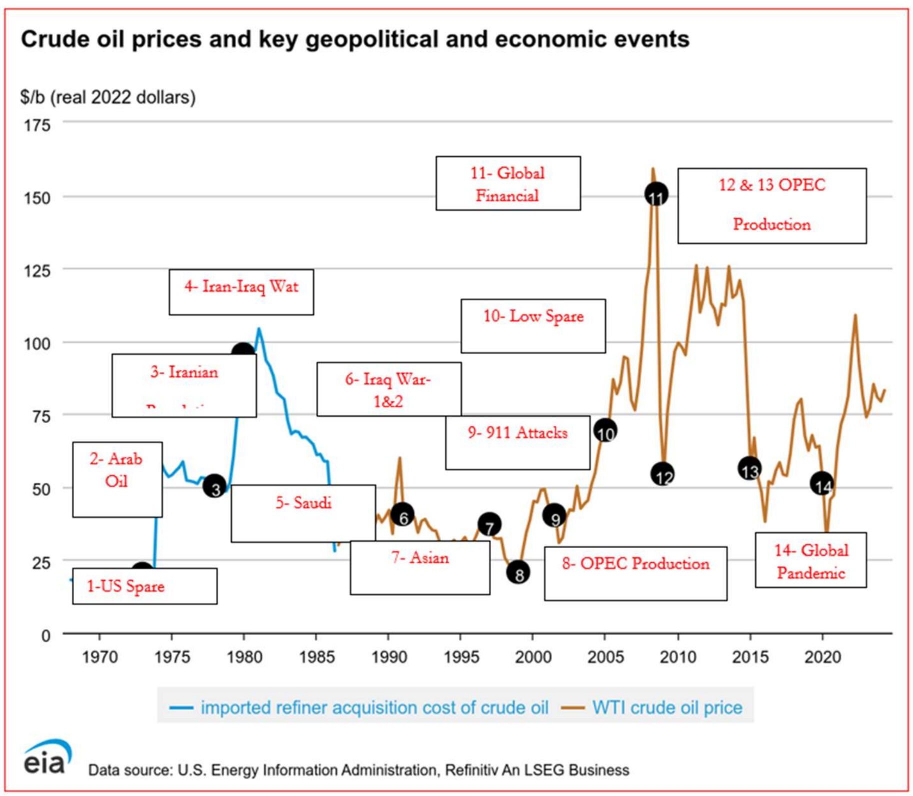
Figure 22



(Sources: EIA, Macrotrends, Statista, OilPrice.com)

73. Illustrated below are oil price movements for the 1970 to 2023 period as related to major political, economic, and business events.

Figure 23



(Source: Author and https://www.eia.gov/finance/markets/crudeoil/spot_prices.php#:~:text=Crude%20oil%20is%20traded%20in,that%20are%20lower%20in%20quality)

74. During the 1970s, the U.S. experienced two **episodic** events or oil "shocks." The first occurred in 1973, and the second was in 1978. On October 6, 1973, the Fourth Arab-Israeli war broke out between Israel and a collation of Arab nations, including Saudi Arabia, Egypt, and Syria.[102] [103] The U.S., which had and continues to maintain formal defense alliances with Israel, supported Israel with a $2.8 billion (equivalent to $20.2 billion in 2024) defense aid package.

75. In retaliation to the U.S. support of Israel, the Arab members of OPEC lowered oil production by 5% and initiated an oil embargo on the U.S. Overall, global oil supplies fell by 14%. Within days of the onset of hostilities, the reduction in production, and the embargo, petroleum prices surged by 71%, rising from $3.01 to $5.12 per barrel. The rapid and unexpected surge in prices dealt a severe, almost debilitating blow to the U.S. economy. Less than three months later, in December 1973, Arab member OPEC oil producers again cut production by 25% from its September levels. In reaction, the price to the U.S. for OPEC-sourced oil rocketed to $11.65 a barrel — an increase of 287% in about 90 days. What followed were gasoline shortages, price spikes, and high inflation. By March 1974, the oil embargo was formally ended by the Arab nations, but its influence on the U.S. economy lasted well into the 1980s. Recognizing its vulnerability to foreign sources and spot market prices, the U.S. Congress established the Strategic Petroleum Reserve (SPR) in December 1975.[104]

76. Due to its high dependency on non-U.S. foreign-sourced crude oil, California is extremely vulnerable to "oil shocks," shortages, and price hikes that may be perpetrated by foreign actors. California has experienced supply shocks due to refinery closures, port disruptions, and global price surges linked to events thousands of miles away. Brent crude, which serves as the benchmark for many of these imports, tends to be more volatile than West

[102] The Editors of Encyclopedia Britannica. (2018). Yom Kippur War | Summary, Causes, Combatants, & Facts. In *Encyclopedia Britannica*. https://www.britannica.com/event/Yom-Kippur-War

[103] Also known as the Yom Kippur War, or Ramadan War.

[104] 42 U.S. Code § 6231 and 42 U.S. Code § 6234

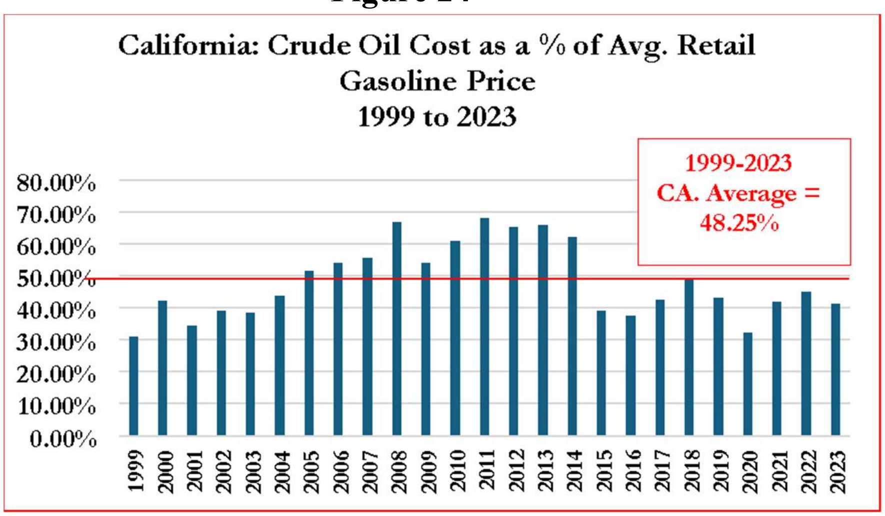
Texas Intermediate. When California's supply is driven by international markets, price spikes happen faster and last longer.[105]

ii. California Crude Pricing

77. In California, environmental factors such as earthquakes, fires, blizzards, heat, and flooding can cause disruptions in crude oil, gasoline, diesel, and aviation fuel production and distribution (transportation). Furthermore, refinery shutdowns, transitions, and decommissions adversely affect the supply of retail gasoline stocks, which rely on crude petroleum as a raw material (feedstock). When those events occur, the spot prices for crude oil stock can spike and are ultimately reflected in higher prices for retail gasoline and other fuels. The price of oil can also be further affected by events such as labor disputes and strikes involving rail and trucking, maritime terminal operational efficiencies, the supply of maritime tankers, employment rates, truck and rail transport, government lockdowns, such as COVID-19, and geopolitical events far from California.

78. The majority of raw material in the production of gasoline is crude oil, which in California has historically averaged 48.25%.

Figure 24



[105] Johnson, J. (2025, April 18). California could lose a large chunk of its refining capacity in a year. San Francisco Chronicle. https://www.sfchronicle.com/california/article/refinery-closures-gas-prices-20279856.php

79. On the West Coast, and particularly in California, refiners tend to pay slightly more for 'first purchase' crude oil than the rest of the U.S. due to low in-state production and the need to import oil from distant sources such as the Middle East.[106] [107]

E. Sable Offshore Corp.

i. Sable Oil Reserves, Capacity and Platforms (wells)

80. According to the company's latest reserve assessments, the total net estimated contingent resources across all platforms amount to 646 million barrels of oil equivalent (MMBoe). This includes a low estimate of 179 MMBoe and a best estimate of 467 MMBoe, with the resource base comprising 86% oil, 13% gas, and 1% natural gas liquids (NGLs).[108] These figures underscore the long-term strategic value of the asset base, not only in terms of short-term output but also in terms of **reserve longevity**, development flexibility, and potential for **scalable economic impact**. With a phased restart strategy already underway and robust reserve validation, Sable's offshore system is positioned for both operational reliability and multi-decade resource contribution to California's economic future.

Figure 25

Sable Platform Capacity				
Platform	**Existing Wells**	**Available well slots**	**Est. Net Production Per Day**	**Est. Restart Date**
Harmony	32	23-27	15.0-19.0 MBOE	15-May-25
Heritage	44	15-17	19.0-23.0 MBOE	Jul-25
Hondo	26	10	6.0-8.0 MBOE	Aug-25

81. Sable's offshore oil recovery infrastructure comprises three key production platforms- Harmony, Heritage, and Hondo- all part of SYU (Santa Ynez Unit). These platforms are designed for high-volume, multi-well production and together **represent one**

---

[106] *California law and refinery closure reflect ongoing challenges for the state's fuel market - U.S. Energy Information Administration (EIA)*. (n.d.). https://www.eia.gov/todayinenergy/detail.php?id=63944

[107] California Crude Oil First Purchase Price (Dollars per Barrel). Eia.gov. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?f=M&n=PET&s=F005006__3&utm

[108] *Sable Offshore Corp. - Events & Presentations*. (2023). Sableoffshore.com. https://sableoffshore.com/events-and-presentations/default.aspx

of the most robust offshore systems along the California coast. As of the second half of 2025 (2H25), Sable anticipates a total production capacity between 40,000 and 50,000 barrels of oil equivalent per day (BOE/D), with near-term output poised to rival the historical 2015 peak of 45,000 BOE/D.[109]

82. Platform Harmony, which resumed production on May 15, 2025, includes 32 existing wells and up to 27 available well slots, targeting a 2H25 production rate of 15,000 to 19,000 BOE/D. Platform Heritage, scheduled to restart in July 2025, features 44 existing wells with 15–17 additional well slots and is expected to deliver 19,000 to 23,000 BOE/D.[110] Platform Hondo, with 26 existing wells and 10 available slots, is projected to come online in August 2025, contributing 6,000 to 8,000 BOE/D..

ii. Sable Production Operational Analysis

83. Operationally, Sable is currently configured to produce between 30,000 to 35,000 barrels of crude oil daily. However, because of its multiple well capabilities, longer-term production yields could be considerably higher. In general, larger producers with 10,000 barrels a day or more in crude oil production require a realized price of $31.00 a barrel to cover fully loaded operating expenses for existing wells.[111] For perspective, the breakeven for a new drilled well ranges between $61.00 to $71.00 a barrel.

84. Based on Sable's estimates and compared to those generated in my analysis as well as those associated with external benchmarks, Sable's operating breakeven is favorable and competitive and falls within the range of other offshore shallow-water producers. Accordingly, there is an "economic" market for Sable's production, which is cost-competitive on a comparable basis based on current and expected Brent prices.

[109] *Sable Offshore Corp. - Events & Presentations.* (2023). Sableoffshore.com. https://sableoffshore.com/events-and-presentations/default.aspx

[110] *Sable Offshore Corp. - Events & Presentations.* (2023). Sableoffshore.com. https://sableoffshore.com/events-and-presentations/default.aspx

[111] "Oil and Gas Activity Edges Higher; Uncertainty Rising, Costs Increase." *Dallasfed.org*, 2025, www.dallasfed.org/research/surveys/des/2025/2501#tab-questions.

Figure 26

Estimated Sable Breakeven Costs as Compared to CA Sources		
Source	**Estimated Breakeven Cost Range**	**Current CA Source of Oil**
Middle East	\$9.00 to \$11.00	Yes
South America	\$7.00 to \$28.00	Yes
Offshore-Shallow	\$37.00 to \$47.00	
Offshore- Deep	\$43.00 to \$53.00	
Offshore-Shallow- Rystad	\$37.00	
Offshore- Deep- Rystad	\$43.00	
North American Shale- Rustad	\$45.00	
Oil Sands- Rystad	\$57.00 to \$75.00	Yes- Canada
Sable Offshore- Estimated	**\$29.00 to \$41.30**	
Note: Ranges vary based on production volumes and regulatory costs.		
Sources: Various and calculated.		

As noted by Rystad, costs for offshore shallow shelf, as well as deepwater producers, declined around 35%. [112] Given Sable's technology, further cost reductions are possible.

iii. Sable Customers and Selling Markets

85. Oil and gas producers sell their output (production) predominantly to refineries, which, in turn, create products such as gasoline, diesel, and aviation fuels and distillates. As crude oil is a global commodity, there are a number of different markets that Sable could potentially sell its production on and to. In California, there are only three major in-state refinery customers representing a combined daily capacity of around 781,000 barrels a day remaining as customers for Sable oil production. All three of these in-state refineries are **heavily dependent on non-U.S. foreign oil** as feedstock to its fuel production process and are **essential to California's economic growth and national security.**

Figure 27

Sable CA. Refinery Customers			
Refinery	**Operator**	**Location**	**Approx. Capacity (bpd)**
Chevron	El Segundo	Southern CA	269,000
PBF Energy	Torrance	Southern CA	149,000
Marathon Petroleum	Carson/Wilmington	Southern CA	363,000
Total Capacity			**781,000**

(Source: Statewide Economic Impacts of Resuming Production at the Santa Ynez Unit (SYU))

[112] *Shale project economics still reign supreme as cost of new oil production rises further*. (2024, October). Rystad Energy. https://www.rystadenergy.com/news/upstream-breakeven-shale-oil-inflation

86. Significantly, any disruption to the crude oil feedstocks in these refineries or any unplanned interruptions to the operations of these refineries will have a detrimental impact on consumer prices. To maintain a viable operational profile, especially in consideration of increased regulatory costs and the profit restrictions imposed upon the refineries by ABX2-1, the **surviving California refineries would benefit from the security and cost advantages of additional in-state oil production**.[113]

87. Sable's oil production will most likely be sold to refineries under long-term contracts, with pricing indexed to the Brent spot market and adjusted for sulfur content, gravity, and California location differential (typically a $2-$5/bbl. discount). As is customary with production, while some portions of Sable's production may be sold on the spot market, Sable is expected to prioritize volume stability and cash flow predictability through structured contracts long-term contracts (6–36 months) with California refineries to **help create price and volume certainty for both Sable and the California consumer**. Spot market sales, which are relatively common in the industry, would most likely cover incremental volumes or provide a hedge for price movement, especially during high and peak demand periods (e.g., summer driving season). Importantly, the **marketability of Sable crude oil is high and lively. California currently imports over 75% of its oil needs, and the decline in local production creates a significant supply gap that Sable is well-positioned to fill with minimal transportation costs and overhead**.[114]

iv. Sable's Pipelines

88. Sable's offshore crude oil production is expected to enter California's intrastate pipeline and refining market, where it is particularly well-suited due to its medium-sour

---

[113] "Governor Newsom Signs Legislation to Prevent Gas Price Spikes and Save Californians Money | Governor of California." *Governor of California*, 14 Oct. 2024, www.gov.ca.gov/2024/10/14/governor-newsom-signs-legislation-to-prevent-gas-price-spikes-and-save-californians-money/.

[114] EIA. (2025). *Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)*. Eia.gov. https://www.eia.gov/outlooks/steo/

quality. Production from the Santa Ynez Unit (SYU) is processed and delivered via the Las Flores Canyon (LFC) facility into **existing infrastructure serving major California refineries** (consumers of Sable production). The consuming refineries are linked to offshore Sable's California production via the Sable-owned Las Flores Pipeline system and connected third-party pipelines and are configured to process medium to heavy sour-grade crude like that produced from SYU and consistent with other oil fields in Kern and San Luis Obispo counties. Collectively, Sable's pipelines have a design throughput capacity of 240,000 barrels a day.

Figure 28

Sable Pipelines				
Pipeline	**Known As**	**Design Capacity (bpd)**	**Estimated Utilization**	**Potential Daily Throughput**
Line 324	Line 901	150,000	85% to 100%	127,500 to 150,000
Line 325	Line 903	300,000	85% to 100%	255,000 to 300,00

89. Lines CA-324 and CA-325 were historically used to transport Santa Ynez Unit (SYU) crude from the onshore Las Flores Canyon Processing Facility to Pentland Station south of Bakersfield and then to connected inland pipeline networks. Pending final clearance under California and federal oversight, Sable intends to open the recommissioned lines to deliver crude to the inland networks for eventual refining into fuels. If both lines are recommissioned and operated near estimated utilization, combined throughput could support ~200,000 bpd, which is more than sufficient for the combined peak output of the Hondo, Harmony, and Heritage platforms.[115] **Assuming Sable produces 31,500 to 40,000 barrels per day, Sable would comprise 10% to 15% of California's daily in-state production for 2024.**

90. Line CA-324 (previously known as Line 901) and Line CA-325 (previously known as Line 903), collectively known as the Las Flores Pipeline System, are critical components of the oil transportation infrastructure associated with Sable's offshore assets.

[115] *Sable Offshore Corp. - Events & Presentations*. (2023). Sableoffshore.com. https://sableoffshore.com/events-and-presentations/default.aspx

These pipelines historically moved SYU crude from onshore Las Flores Canyon treatment facility to Pentland Station south of Bakersfield and then to connected inland California markets. Line 324 has a maximum permitted throughput capacity of 150,000 barrels per day (bpd), while Line 325 is permitted at 300,000 bpd. **The recommissioning of Sable Lines 324 and 325 would reduce the need for marine tanker transport, reduce emissions risk, and help restore a critical energy corridor within the state's coastal infrastructure network.**[116]

v. Potential Economic Impact on State, Santa Barbara & Adjacent Counties

91. Sable projects daily production of 45,000 BOE or 31,500 barrels of crude oil, with multiple scenarios modeled and developed extending to higher volumes to test potential economic impact. Assuming a stable Brent benchmark oil price of $70 per barrel, the gross revenue impact of operations can be scaled accordingly over a full year (365 days) and estimated to be $804,825,000.

92. The analysis assumes a conservative 8% net profit margin, which reflects the high capital and operating costs associated with offshore oil production. California levies an 8.84% corporate income tax, which would apply to any taxable income generated in-state. Additionally, property taxes, estimated at $5 million annually for the Las Flores Canyon facility and related infrastructure, along with employment taxes from a workforce of roughly 340 full-time employees (averaging $118,000 per year), provide further contributions to state and local revenue.

Figure 29

[116] *Plains All American Reports Fourth-Quarter and Full-Year 2023 Results; Announces 2024 Guidance - Fri, 02/09/2024 - 08:00*. (2023). Plains All American Pipeline. https://ir.plains.com/news-releases/news-release-details/plains-all-american-reports-fourth-quarter-and-full-year-2023

Sable Production & Potential Contribution to CA State & Local Revenues								
Daily BOE Production	Employee Count	Est. Annual Gross Revenue	Est. Net Profit	Est. Sales Tax	Est. CA. Corporate Tax	Actual Property Tax	Est. Payroll Tax	Estimated Contribution to Total State Revenue
45000	340	$1,314,000,000	$105,120,000	$4,763,250	$9,292,608	$5,000,000	$2,407,200	**$21,463,058**
100000	758	$2,920,000,000	$233,600,000	$10,585,000	$20,650,240	$5,000,000	$5,363,636	**$41,598,876**
250000	1894	$7,300,000,000	$584,000,000	$26,462,500	$51,625,600	$5,000,000	$13,409,091	**$96,497,191**
500000	3788	$14,600,000,000	$1,168,000,000	$52,925,000	$103,251,200	$5,000,000	$26,818,182	**$187,994,382**
1000000	7576	$29,200,000,000	$2,336,000,000	$105,850,000	$206,502,400	$5,000,000	$53,636,364	**$370,988,764**
Assumes $80/BOE, 8% net margin, 7.25% sales tax on 5% taxable spend of revenue, 8.84% corporate tax, $5.0 property tax, and 6% payroll tax on $118K average salary for 550 FTEs)								

(Source: author's calculation)

93. Offshore oil infrastructure, such as platforms, pipelines, and the onshore treatment facility, is subject to local property taxation, which directly contributes to county-level general funds. Sable's offshore platform operations, maintenance, and transportation via pipelines, the potential economic contributions to the local communities are substantial. The three offshore platforms are estimated to produce approximately 31,500 to 50,000 barrels per day- totaling around 11 million barrels annually of crude California oil. Assuming this level of output could potentially generate an estimated **$21.5 to $41.6 million per year in combined local and state revenues**, including sales tax, corporate tax, property tax, and payroll taxes. This includes contributions to Santa Barbara County for hosting the LFC treatment facility and onshore pipeline infrastructure, San Luis Obispo County for service logistics and marine jurisdiction, and Kern County through indirect participation in the regional energy supply chain.

94. Santa Barbara County, in particular, stands to benefit economically the most from Sable operations. Historically, oil-related revenues in the county have funded essential public services such as fire protection districts, law enforcement staffing, road maintenance, and local school districts. The return of Sable's offshore activity, coupled with the rehabilitation of pipelines and treatment facility assets, will likely help restore and expand Santa Barbara's revenue flows, enabling the county to address long-standing infrastructure gaps and growing public service needs.

95. In San Luis Obispo County, where marine service operators and support logistics for offshore operations are based, Sable's activities will contribute to business tax bases, vendor income, and contractor employment, particularly in port services, environmental

compliance, and vessel support. While Kern County may see more limited direct benefits due to its inland location, increased activity at Pentland Station as the terminus of the Las Flores Pipeline, supply chain links, such as heavy equipment vendors, staffing agencies, and technical services, could nonetheless generate income and modest revenue benefits tied to Sable's restart.

96. The potential fiscal contributions associated with the recommissioning and operations of Sable's three platforms primarily benefit Santa Barbara County, which hosts Sable's offshore infrastructure and the LFC treatment facility; San Luis Obispo County, through its proximity to offshore jurisdiction and logistical support activities; and to a lesser extent, Kern County, which may participate indirectly through the supply chain and remote platform, processing, and pipeline support services. [117] [118]

vi. Potential Economic Implications of Sable Production on Employment and Personal Income

97. The restart of offshore oil production by Sable will potentially deliver a substantial and sustained employment and income boost to the Central Coast region of California, particularly to Santa Barbara County. Sable projects a steady-state offshore workforce of approximately 220 full-time California-based employees, supported by an additional 120 steady-state contractors, collectively **totaling around 340 personnel**.

Figure 30

Estimated Impact of Sable Production on Employment, Wages & Earnings			
Job Type	**Estimated Headcount**	**Avg. Salary**	**Total Payroll Impact**
Sable Employees (CA-based)	~220	$120K–$150K/year	~$30M–$33M/year
Steady-State Contractors	~120	$90K–$110K/year (blended)	~$10M–$13M/year
Total Annual Offshore Payroll	**~340**		**~$40M–$46M/year**

(Source: Calculated)

[117] *Oil & Gas | CA State Lands Commission*. (n.d.). https://www.slc.ca.gov/oil-gas/

[118] *Cultivation Cap & Eligible Business License Applicants Lists | Santa Barbara County, CA - Official Website*. (2025). Countyofsb.org. https://www.countyofsb.org/1175/Energy-Division

98. As indicated, wages and salaries in the oil and gas industry are higher than overall national and California averages. Based on Sable's production scale-up and estimates, the average salaries for direct employees are estimated to range between $120,000 and $150,000 per year, and indirect contractors' wages and salaries are estimated to average between $90,000 and $110,000. Collectively, the combined annual direct employee and indirect contractor payroll is estimated to potentially **range between $40 million and $46 million**.

99. The economic ripple effect from Sable's offshore operations is potentially significant and multidimensional. The direct payroll infusion of $40M[119] annually translates into high-value job creation and regional income growth. Public sector revenues will similarly rise, supporting core community functions and offsetting fiscal pressures in counties historically tied to the energy economy. Santa Barbara County, as the principal host of offshore and treatment facility infrastructure, will be the primary recipient of both direct economic stimulus and long-term public finance benefits, while San Luis Obispo and Kern Counties will also share in employment, procurement, and service-related gains.

100. Due to the nature of Sable's production profile, as well as its considerable operational standards, both direct and indirect jobs are high-paying, skilled positions in platform operations, marine logistics, environmental safety, and pipeline maintenance. The majority of these jobs will most likely be concentrated in Santa Barbara County, where the offshore platforms and the Las Flores Canyon (LFC) treatment facility and Las Flores Pipeline System control center are located. Many of these employees will live, spend, and pay taxes locally, contributing significantly to the region's labor income base and consumer-driven economic activity. Moreover, the presence of such high-wage positions stimulates secondary employment effects, including induced demand for housing, transportation, education, healthcare, and local services. Based on various production volumes and labor

[119] *Sable Offshore Corp. - Events & Presentations*. (2023). Sableoffshore.com. https://sableoffshore.com/events-and-presentations/default.aspx

multipliers in the energy and marine logistics sector, Sable could generate between 1,150 to 25,500 in indirect and induced (contractor and affiliated employees) employment in Santa Barbara, Kern, and San Luis Obispo counties and statewide as a result of Sable's offshore restart. The high average salaries associated with these direct roles also imply elevated household purchasing power, further driving economic multipliers in retail, hospitality, and professional services within the local economy. **Sable's activities, therefore, represent not only direct income generation but also a mechanism for broader economic revitalization, particularly in post-pandemic coastal California regions with high service-sector dependence**.

101. Scaling from Sable's benchmark of 31,500 bpd, supported by approximately 340 direct offshore personnel, the **expansion to a 60,000-bpd production** level would support an estimated 508 to 652 direct workers, assuming a consistent ratio of 1 employee per 92 barrels produced daily. Of this projected workforce, the majority would be full-time employees concentrated in platform operations, marine logistics, environmental oversight, and pipeline maintenance. Applying industry-standard compensation levels, employees earning $120,000 to $150,000 annually with contractors averaging $90,000 to $110,000 annually, the total direct payroll would be $78.24 to $97.8 million per year. This would represent one of the largest wage-driven energy operations in California and likely the United States, injecting massive purchasing power into local economies through increased housing demand, service consumption, and tax contributions.

102. Coastal counties such as Santa Barbara, Ventura, and San Luis Obispo would see the most immediate impact due to proximity to offshore infrastructure, marine terminals, and workforce housing demand. Meanwhile, inland counties like Kern would benefit from increased activity at Pentland Station as the terminus of the Las Flores Pipeline, expanded supply chains and service contracts tied to energy logistics, environmental services, and oilfield technology. In aggregate, Sable's production could have transformative economic implications, generating billions in direct revenue, thousands of high-wage jobs, and

significant fiscal resources for public infrastructure and local governments, making it one of the most economically consequential energy projects in California's modern history.

vii. Potential Implications of Sable Production on California Oil Prices

103. Many factors, such as contract terms and negotiation, macroeconomic activity, work and lifestyle habits, and choice of transportation play into the demand for fuels, and prices paid for crude oil and refined products. The most significant determinant, as was so cruelly learned in the 1970s and 1980s, is petroleum supply security. California is virtually at the mercy and held captive to crude supplies from foreign petrostates and is, therefore, highly vulnerable to any disruptions in the supply chain and geopolitical events. Furthermore, California's use of foreign oil from various sources furthers the political ambitions of those nations, which may be contradictory to the interests of the U.S. and, through the constant use of maritime vessels, contributes significantly to greenhouse gas emission.

104. Despite California's efforts, the demand for fossil fuels is not declining as quickly as CARB had projected, and in fact, has only declined 11% over a twenty-plus year period. The addition of Sable production from its three offshore platforms and the use of its two existing pipelines would have a favorable impact on California's energy needs and would help alleviate stresses associated with its dependency on foreign sources. The introduction of Sable production into the California refinery system could have a **favorable economic impact ranging between $3.283 to $3.456 a barrel** over imports, depending on the final terms of trade.

Figure 31

POTENTIAL INFLUENCE ON CALIFORNIA OIL REFINERY PRICES OF CRUDE STOCK OIL						
Sable Production at Scale (Barrel/day)	Sable Annual Volume(In Barrels)	Share of California In-State Production	Price to Refiners (5%) ($)	Brent Discount (5%) ($)	Production-Weighted Average Price with Sable Production	Potential Savings ($) with Sable Per Barrel
31500	11.50M	10%	65.65	62.37	65.33	3.28
40000	14.60M	12%	65.65	62.37	65.12	3.28
55000	20.08M	15%	65.65	62.37	65.01	3.28

(Source: Calculated)

IV. SUMMARY CONCLUSIONS

A. Summary and General Conclusion

105. Based on the data, research into prevailing literature, and my analysis, my conclusion is that the production of oil from Sable's three offshore platforms and the associated use of its Las Flores Pipeline System to transport Sable's production to market will not irreparably harm the public.

106. The addition of production of oil from Sable's three offshore platforms and the associated use of its Las Flores Pipeline System to transport its offshore production would benefit the public because it will have a **favorable economic impact on California's overall energy situation**, as well as have a favorable influence on local employment and tax revenues. Furthermore, the addition of production from Sable's three offshore platforms and the use of Sable's Las Flores Pipeline System to transport its production to market would have a positive influence on consumer retail gasoline, diesel, and aviation fuel prices, would **improve and strengthen California's energy and economic security and avoid irreparable harm to consumers**.

B. Pertinent Findings

107. With the continuing decline of in-state oil production, the pending permanent shutdown of two major oil refineries collectively representing the loss of 10.5 million gallons of gasoline per day, growing dependencies on non-U.S. sources for oil and, now gasoline, as well as the highest retail gasoline prices in the U.S., California is confronting a potential energy crisis.

- While overall U.S. field production has increased 66% from 1990 levels, California's field production declined 61%, and 68% decline from its peak production in 1985.
- California is the 2nd largest consumer of petroleum and the largest consumer of aviation fuel in the U.S.[120] In 2023, Californians consumed over 500 million

[120] U.S. EIA, Crude Oil Production, Annual, Thousand Barrels, 2023.

barrels of oil (1.8 million per day), 13.119 billion gallons of gasoline, 3.6 billion gallons of diesel fuel, and over 216 million gallons of aviation fuel.

- Nearly 100% of California's non-U.S.-sourced imported oil is delivered to its refineries via maritime vessels, which are significant contributors to GHG emissions.
- California is highly vulnerable to oil supplies and prices of foreign providers. Since 2005, California's dependency on non-U.S. foreign oil has increased by 19.43%, while its in-state oil production has fallen by 55.22%.
- California is virtually completely dependent on maritime vessel transportation for the importing of oil from non-U.S. foreign sources.
- California's retail gasoline prices routinely average 50% greater than the U.S. national average.
- California's oil and gas industry represents around 8% of its total GDP and employs over 148,000 workers directly and over 536,000 indirectly, and generates around **$47.9 billion in state and local tax revenues for 2022**.
- Californians consume between **30 to 33 million gallons of gasoline a day and around 9.9 million gallons a day of diesel fuels. Oil and gasoline consumption in California has not declined significantly over a twenty-five-year period**.
- California oil and gasoline consumption is relatively inelastic. Since 2001, the consumption of gasoline has decreased by only 11%; total oil consumption has decreased by 22% (mostly due to the switch to renewables for power generation).
- California is highly dependent on foreign, non-U.S. oil imports to meet its demand for petroleum-based fuels and other products; California imports of foreign, non-U.S. sourced oil have increased 69%.

- California's dependency on foreign oil sourced from petrostates such as Iraq, Saudi Arabia, and the U.A.E, as well as Brazil, Ecuador, and Guyana, is expected to increase in the coming years, making the State more vulnerable to geopolitical events and swings in Brent oil market prices.
- California's dependency on foreign gasoline and diesel fuels sourced from Singapore, India, Japan, South Korea, and China is expected to increase in the coming years, making the State more vulnerable to geopolitical events and disruptions in the supply chain.

C. Key Conclusions

108. Based on my findings and analysis of Sable and its two existing onshore pipelines, the following conclusions are offered. The use of the Las Flores Pipeline System to carry Sable's production to market will not irreparably harm the public. **Indeed, to the contrary, as is summarized in this declaration, allowing the use of the Las Flores Pipeline System to carry Sable's production to market –would benefit the public and avoid irreparable harm to consumers** for the reasons articulated in this declaration and summarized below.

- As configured, Sable is capable of producing 30,000 to 50,000 barrels of oil per day from its three offshore platforms. At this level, Sable's production would represent approximately **10 to 15% of all California in-state production** based on 2024 levels.
- Sable's existing Las Flores Pipeline System provides adequate transportation for its offshore production.
- The addition of Sable production using its three offshore platforms and the associated use of its existing Las Flores Pipeline System, indicates that Sable would be **cost competitive** with oil sourced from land-based wells, as well as a number of foreign sources, at various production levels (scale).

- Sable has immediate and long-term oil reserves that, if placed into production, would create significant economic value to the state of California, as well as Santa Barbara, Kern, and San Luis Obispo counties. The potential impact of production is estimated to range between **$21.5 to $41.6 million a year** over a multi-year period depending on production scale.
- The addition of Sable production using its three offshore platforms and the associated use of its existing Las Flores Pipeline System would have a favorable impact and contribution to local employment. Based on various production volumes and labor multipliers in the energy and marine logistics sectors, Sable could generate between **340 to over 7,500** in direct employment, and between 1,150 to 25,500 in indirect (contractor and affiliated employees) employment in Santa Barbara, Kern, and San Luis Obispo counties and statewide as a result of Sable's offshore restart.
- The addition of Sable production using its three offshore platforms and the associated use of its existing Las Flores Pipeline System would **enhance California's energy security** through the use of steady-streamed California sourced oil to the remaining California refineries.
- The addition of Sable production using its three offshore platforms and the associated use of its existing Las Flores Pipeline System would introduce **more California oil into the State's refinery system.**
- **The introduction of Sable production into the California refinery system through the Las Flores Pipeline System could have a favorable economic impact ranging between $3.283 to $3.456 a barrel over imports**.

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

Michael A. Mische

Exhibit A

MICHAEL A. MISCHE
MBA, MS, Cert-AI.
Associate Professor of Professional Practice

INTRODUCTION

Widely quoted in the media, including, The Wall Street Journal, Business Insider, The Washington Examiner, San Jose Mercury News, The Irish Business Post, FOX News, FOX Business, KNX-LA, KFI-LA, CBS and NBC, Professor Michael A. Mische is recognized as one of the world's foremost authorities on the management consulting oil and gas industries. He has testified as an expert before the Senate, in high-profile litigation and criminal cases involving management consulting, and has been cited in over 1,100 mainstream publications, interviews, reviews, and research papers. He is highly regarded for his Management Consulting Annual Outlook Report, his published research on oil in Venezuela, and for his major publication on Bidenomics, which was the most comprehensive comparative examination of the U.S. economy for the 2019 to 2023 period, and *A Study of California Gasoline Prices* (2025) which is a fifty-year study of the price determinants in the Golden State. In 2023, Michael released his eighth book, *"CasePro: The Consultant's Critical Thinking Approach to Case Analysis,"* and is the author of seven other books, including a world-wide best-seller with co-author, the late Warren G. Bennis.

Mische joined USC in 1997 as an adjunct professor. Since 2016, Michael has been a fulltime faculty member of the Marshall School of Business, University of Southern California while maintaining an exceptionally high-profile presence as a thought leader in the consulting industry. He is the 2018 recipient of USC's Golden Apple Award for Teaching Excellence and a co-recipient of the 2019 Service Excellence Award. Mische maintains a highly active consulting profile among elite consulting firms and governments with projects spanning major consulting issues, oil & gas prices, the economy, AI in consulting, and issues related to national economic security.

POSITIONS HELD (ACADEMIA)

- **University of Southern California**, Marshall School of Business. Los Angeles, CA. (1997-Present).
  - Associate Professor of Professional Practice & Curriculum Leader: Management Consulting.
    - Faculty Lead for the Certificate in Strategy & Management Consulting.
    - Redesigned consulting curriculum to be more relevant and competitive with Harvard.
    - Designed & implemented a new MOR course offering, *Case Analysis for Consultants: A Critical Thinking Approach*, MOR 499, which provided for interactions between MBAs from the MOR 557 class with UGs from MOR 462.
    - Co-designed & co-teach a new MBA course offering with Prof. Shon Hiatt titled, *" MOR 599-The Business of Energy in the 21st Century."* Scheduled for Spring 2025.

- Co-designed & co-taught, with Jerry Giaquinta, a new course in 2020, (BUCO/MOR 499), a cross-cultural, project-based course; simultaneously taught via Zoom with ICU in Tokyo, Japan.
- Redesigned and upgraded USC's Certificate in Strategy & Management Consulting. (2023).
- Instituted a quantitative national ranking system for MBA consulting programs:
  - Helped to shift USC 2022 Ranking to 9th, compared to 2015 which was not in the Top 30.
  - Helped increase MBA placement in consulting from 16% to 30%. 2015 to 2022.

- **USC Service Activities**
  - Conducted recruiting bootcamps for both MBA and MS students for placement into consulting. (2023-2024).
  - Co-hosted KPMG CEO Paul Knoop on campus for recruiting purposes. (2024).
  - Co-leading, with Paul Adler, Deloitte Sustainability Consulting Case. (2024).
  - Authored new Experiential Learning Center (ELC) exercise based on an actual management consulting situation. (2023).
  - Faculty recruiter, USC Football. Speak with non-committed football recruits and their families about USC academics and the "life of a student athlete." (2022-present).
  - Faculty Adviser, MCSC, the largest MBA student club at Marshall. (2022-present).
  - Implemented career coaching services for MBAs with USC's Career Resources Center. (2023).
  - Faculty coach (informal) USC Marshall MBA Black Students Case Competition Team. (2022).
  - Co-coached (with Carl Voigt) USC Marshall Case Competition Team. (1999 – 2001).
- **USC Teaching Awards**
  - USC Golden Apple Teaching Award. (2018).
  - MOR Service Award. Co-recipient. (2019).

- **USC Marshall School of Business- Teaching Responsibilities:**
  - **<u>MBA-Graduate</u>** **<u>Course</u>** **<u>Year</u>**

MOR 599	The Business of Energy in the 21st Century	2025
MOR 554	Strategy Innovation & Change	2015- Present
MOR 557	Management Consulting	2015- Present
MOR 559	Strategic Transformation & Renewal	1997- Present

- **Undergraduate** **Course** **Year**

MOR 499	***New-*** Case Analysis for Consultants	2022, 2023
MOR/BUCO 499	Cross Cultural Collaboration- Project Based	2020
MOR 473	Leading High-Performance Teams	2016- Present
MOR 462	Management Consulting	2014- Present
BUAD 497	Strategy- Case Based	2014 -2016
MOR 463	Organizational Behavior	2013- 2018

POSITIONS HELD- PRIVATE SECTOR (FOR PROFIT)

- **Synergy Consulting Group, Inc.** (1993-Present). *CEO & Chairperson of the Board*. Scottsdale, AZ and State College, PA.
    - Significant clients include United States, Kingdom of Saudi Arabia, several Fortune 50s and several Elite 8 management consulting firms.
    - Special consultant to HRH, Kingdom of Saudi Arabia. (2020-2022).
    - Special consultant to U.S. Government. (Ongoing).
    - Practice specializations include:
        - Strategic Assessment & Positioning.
        - Organizational Performance.
        - Strategic Innovation .
        - Energy Policy as Related to Oil & Gas.

- **Andersen Consulting (Accenture).** (1995-2000). *Special Consultant to Senior Practice Leadership & Management Committee of the Firm*. Chicago & Los Angeles.
    - Advisor on Global Repositioning & Practice Lines Restructuring relating to "Process Transformation."
    - Co-authored "Building Process Excellence: Lessons from the Leaders."
    - Co-developed/Contributor to the AC Reengineering & Strategic Planning Methodology.
    - Keynote Speaker: Andersen Partners & Consultants Innovation & Software Spectacular Meeting, San Antonio. (1996).
    - Designated "Associate Partner" for administrative, NDA, and confidentiality purposes.

- **AT Kearney.** (1991 to 1993). *Principal, Management Consulting Services.* Chicago, IL.
  - Special Project- Internal Restructuring and Cost Reduction.
  - Special Project- Repositioning Strategic Technology Services for Sale.

- **KPMG.** (1983 to 1992). *Principal, Management Consulting Services.* Montvale, NJ.
  - One of the youngest consulting partners elected in the history of the Firm.
  - PIC & Practice responsibilities included leading/co-leading national services in:
    - Strategy & Transformation Consulting.
    - Transactions Management Services (M&A).
    - Innovation & Advanced Technologies.
  - Instructor, SDLC and Project Management.
  - Co-led/managed over $58 million in direct engagement billings (Over $100 million in aggregate).
  - Maintained one of the highest Net to Gross ratios in the firm.
  - Member, KPMG Practices & Methods Review Committee.
  - Member, AICPA Peer Review Committee for PwC.

NOTABLE CONSULTING ACTIVITIES (Partial)

- **2025.** U.S. Energy Production as Related to Oil & Gasoline Independence.
- **2024.** Lead Consultant & Expert Witness on behalf of BCG in BCG v. GameStop litigation. (2023-2024).
- **2024.** Lead Consultant. Bidenomics: Facts, Figures & Everything that Americans Should Know. (February 2024).
- **2023.** Lead Consultant. Analysis of the Implications of the Strategic Petroleum Reserve on U.S. War Readiness. Classified. (2023).
- **2023.** Analysis of California's Profit Gouging Tax. (January 2023).
- **2023.** Analysis of Biden Administration's Oil & Gas Policies. (November 2022).
- **2023.** Analysis of U. S. Oil & Gas Prices. Oil & Gas Association. Distributed to U.S. Congress. (October 2022).
- **2018-2021.** Kingdom of Saudi Arabia. Lead Advisor for the development of the strategic plan for the "Innovation Superhighway" linked to Vision 2030. https://www.vision2030.gov.sa/media/rc0b5oy1/saudi_vision203.pdf.
- **2018-2021.** Kingdom of Saudi Arabia. Appointed Senior Advisor to the Saudi Public Investment Fund (Taqnia), a $925 billion investment fund for the design and implementation of co-innovation and co-investment funding and investment selection processes and organization capable of supporting 13 different economic sectors. https://www.pif.gov.sa.

- **1997.** Reengineering Government Initiative for Vice President Al Gore. (May- August 1997).

EXPERT TESTIMONY & PANEL PARTICIPATION (Partial)

- **2023/2024.** Expert Witness. U.S. Federal District Court. For and on behalf of BCG (Boston Consulting Group) v. GameStop. https://law.justia.com/cases/federal/district-courts/delaware/dedce/1:2022cv00363/78379/76/.
- **2024.** Opined (informal comments) on draft Senate Bill *"To prohibit conflict of interests among consulting firms that simultaneously contract with the Government of the People's Republic of China and the United States Government, and for other purposes."* https://www.hawley.senate.gov/sites/default/files/2024-02/Hawley-Time-to-Choose-Act.pdf.
- **2023.** Expert Witness. Testimony before California Senate on California Oil & Gas Price Gouging. (February 22, 2023). See, Mische at 2-hour, 3 min. mark. https://www.senate.ca.gov/media/senate-energy-utilities-communications-committee-20230222/video
- **2023.** Opined on the "Effects of a Windfall Profit Tax" on U.S. Oil & Gas Competitiveness. United States House of Representatives. Washington, D.C. (January 2023).
- **2023.** Expert Witness. Presentation before the California Foundation on The Environment and The Economy on why California gasoline prices are higher than national averages and the accretive costs of a windfall profit tax. February 10, 2023. Napa, California.
- **2023.** Moderator. "Innovation Factories, Unicorns and Competitive Positioning." Featuring Linda K. Yates, Author and CEO, Mach 49. (November 2022).
- **2023.** Expert Witness, California Senate. "Why Are Oil & Gas Prices So High in California?" Californians Against Higher Taxes Press Conference. Carried live and covered by AP. (November 28, 2022).
- **Prior 2022 (partial).**
  - Material Witness, FARA case. Subpoenaed for and on behalf of the U.S. Government, Southern District of New York (U. S. v. Zuberi). Los Angeles, CA.
  - Subpoenaed as material witness on behalf of the U.S. Government in a political financial and foreign influence investigation (FARA).
  - Testified before United States Grand Jury, 2019/20.
  - Testimony contributed to a conviction and 12-year sentencing in a federal penitentiary on FARA violations. https://www.justice.gov/usao-cdca/pr/political-donor-sentenced-12-years-prison-lobbying-and-campaign-contribution-crimes-tax
  - Expert Witness, for and behalf of major Fortune 500. Witness in the analysis of movie theater operations as related to the Supreme Court Consent Decree of 1948, 2016/17. Los Angeles, CA.
  - Expert Witness, for and behalf of Plaintiff, Magic Chef (Owned by Berkshire Hathaway).
  - Expert Witness, for and on behalf of a Private Client. Witness in the analysis of management consulting services, project management and the application of AICPA Code of Professional Ethics as related to management advisory services, 1988. Miami, FLA.

MEDIA COVERAGE & CITATIONS: 2022-2025 (partial list)

- Quoted or cited over **1,225** times in academic and research works (Academia.com).
- Quoted over **300** times in the media in 2022 - 2025.

- **2025.** Mische interviewed. ***Fox Business.*** *University of Southern California Professor Michael Mische explains his study on gas prices being driven up due to high taxes and policies*. (2025, April 4). https://www.foxbusiness.com/video/6370989691112.
- **2025.** Mische interviewed. ***John Kobylt Show; KFI AM 640.*** (2025, April 8). *Why Are CA Gas Prices So High?* https://kfiam640.iheart.com/featured/the-john-kobylt-show/content/2025-04-08-1119-the-john-kobylt-show-why-are-ca-gas-prices-so-high-0408/.
- **2025.** Mische quoted. ***Washington Examiner***. Faria, Z. (2025, April). *California Democrats are responsible for high gas prices*. https://www.washingtonexaminer.com/opinion/beltway-confidential/3366221/california-democrats-responsible-high-gas-prices/.
- **2025.** Mische quoted. ***California Globe***. (April 3, 2025). *California's High Gas Prices Climbing Over $5.00 Per Gallon – Again*. https://californiaglobe.com/fr/californias-high-gas-prices-climbing-over-5-00-per-gallon-again/.
- **2025.** Mische quoted. ***Business Insider.*** Thompson, P. (2025, April 8). *5 consulting contracts cut by DOGE show what government is targeting*. https://www.businessinsider.com/doge-consulting-crackdown-what-contracts-are-being-cut-2025-4.
- **2025.** Mische quoted. ***Pleasanton Weekly.*** Hunt, T. (2025, April 10). *USC study confirms state policies drive up gas prices*. https://www.pleasantonweekly.com/blogs/tim-talk/2025/04/10/usc-study-confirms-state-policies-drive-up-gas-prices/.
- **2025.** Mische quoted. ***Daily News***. Board, T. E. (2025, April 6). *Can California get real about high gas prices?* https://www.dailynews.com/2025/04/06/can-california-get-real-about-high-gas-prices/
- **2025.** Mische quoted. ***KTLA.*** Turner, A., & Sternfield, M. (2025, March 31). *Policies, not greed, driving California's sky-high gas prices, study finds*. https://ktla.com/news/california/policies-not-price-gouging-to-blame-for-californias-soaring-gas-prices-study-finds/.
- **2024.** Mische quoted. ***Washington Examiner,*** "USC estimates California fuel could rise by up to 90 cents per gallon next year." (11/20/24). https://www.washingtonexaminer.com/news/3235752/usc-estimates-california-fuel-could-rise-by-up-to-90-cents-per-gallon-next-year/.
- 2024. Mische quoted. *The Irish Business Post,* "Grant Thornton Irish Partners Mull Debt Deal in Growth Plan" (July 21, 2024). https://www.businesspost.ie/news/debt-deal-on-table-as-grant-thornton-mulls-overhaul-of-partnership-structure/.
- 2024. Mische quoted. *The Wall Street Journal,* "Consultants Are Paid to Fix Businesses. Why Can't They Fix Their Own? (March 16, 2024). https://www.wsj.com/lifestyle/careers/consultants-are-paid-to-fix-businesses-why-cant-they-fix-their-own-1ed9bb04?st=6lijni2puvf4t7s&reflink=desktopwebshare_permalink.
- 2024. Mische quoted. *Newsweek, "Californians Need $1,000 More To Pay 2025 Gas Prices."* (11/21/24). https://www.newsweek.com/california-2025-gas-prices-increase-1989321.
- 2024. Mische quoted. *Institute of Energy Research.* "California Gasoline Prices Will Skyrocket." (11/29/24). https://www.instituteforenergyresearch.org/fossil-fuels/gas-and-oil/california-gasoline-prices-will-skyrocket/.

- 2024. Mische quoted. *CBS 8, San Diego*. (11/21/24.) https://www.cbs8.com/article/news/local/california-drivers-gas-costs-2025/509-0ec7e8d0-8d2e-4540-9235-c6620628fcdb.
- **2024.** Mische quoted. ***FOX 11, LA***. (11/20/24). https://www.foxla.com/news/californians-will-pay-much-more-next-year-keep-up-2025-gas-prices-study
- **2024.** Mische interviewed. ***860 AM, LA***. (12/26/24). https://860amtheanswer.com/news/regional/1f1b8870-c3bd-11ef-8dfd-d3251992d201
- 2024. Mische quoted. *Arizona Daily Sun*. "USC estimates California fuel could rise by up to $1.15 cents per gallon next year." (11/20/24). https://azdailysun.com/usc-estimates-california-fuel-could-rise-by-up-to-1-15-cents-per-gallon-next/article_7aa9d45c-a75d-11ef-aee1-df0e25f64341.html.
- **2024.** Mische quoted. ***Courthouse News Services***. "California Lawmakers Consider Newsom's Oil Profit Penalty." (2/23/23). https://www.mresearch.com/wp-content/uploads/California-lawmakers-consider-Newsoms-oil-profit-penalty-plan-_-Courthouse-News-Service.pdf
- 2023. Mische quoted. *The Wall Street Journal*, "For Once, Rookie Consultants Don't Have Enough to Do." (August 4, 2023). https://www.wsj.com/articles/consultants-bain-kmpg-ernst-young-boston-consulting-bcg-recruits-layoffs-1a2629fd.
- 2023. Mische quoted. ***ExtractingFact.com***, "Three Things Governor Newsom Should Learn from the Special Hearing Session." (March 14, 2023). As University of Southern California professor Michael Mische put it: *"The fact is, we haven't proven any cases of price gouging by oil companies or refiners … As recently as November 2022, we had a court case in the U.S. District Court in San Diego tossed out. The list goes on and on."* https://www.extractingfact.com/news/statewide/three-things-newsom-should-learn-from-the-special-session-hearing/.
- 2022. Mische quoted**.** ***Seattle Times***, "California Eyes Penalties for Oil Companies Big Profits." (December 4, 2022). https://www.seattletimes.com/business/california-lawmakers-to-meet-eye-big-oils-high-gas-prices/.
- 2022. Mische quoted. ***San Jose Mercury News***, "Should California Tax Oil Profits." (November 29, 2022). https://www.mercurynews.com/2022/11/29/should-california-tax-oil-profits-gas-spike-hearing-sets-stage-for-contentious-debate/.
- 2022. Mische quoted. ***Consumer Watchdog,*** "Should California Tax Oil Profits: Gas Spike Hearing Sets Stage for Contentious Debate." (November 29, 2022). https://consumerwatchdog.org/news-story/should-california-tax-oil-profits-gas-spike-hearing-sets-stage-contentious-debate.
- 2022. Mische quoted. ***East Bay Times,*** on oil and gas prices in California. (November 2022). https://www.eastbaytimes.com/2022/11/29/should-california-tax-oil-profits-gas-spike-hearing-sets-stage-for-contentious-debate/.
- 2022. Mische quoted. ***ArcaMax Business,*** on oil and gas taxes. (November 29. 2022). https://www.arcamax.com/business/businessnews/s-2755516-p2.
- 2021. Mische quoted. ***Politico***, on political pay for play. (February 2021). https://www.politico.com/news/2021/02/12/imaad-zuberi-biden-inner-circle-468816.
- 2021. Mische quoted. ***Washington Examiner***, on FARA conviction. (February 2021). https://www.washingtonexaminer.com/news/donor-ties-biden-trump-clinton-obama-sentenced-12-years-prison.

BOOKS BY MICHAEL MISCHE

- **2025.** Pending & Under Contract: *Management Consulting: Professional Practice, Responsibility & Ethics.* Target publication date August 2025.
- **2023.** *CasePro! The Consultant's Critical Thinking Approach to Case Analysis.* Author. ISBN: 978-1-7935-1400-4. (Cognella Publications, January 2023).
- **2017.** *Management Consulting: Today & Tomorrow.* Contributing Author. ISBN: 978-1-138-12428-8 (Routledge, 2017).
- **2000.** *Strategic Renewal: Becoming a High-Performance Organization.* Author. ISBN: 0-13-021919-3. (Prentice Hall, 2000). Adopted for use by 8 MBA programs.
- **1996.** *The 21st Century Organization: Reinventing Through Reengineering.* Co-Authors- Warren Bennis & Michael Mische. ISBN: 0-89384-273-7. (Jossey-Bass, 1996). Reached Top-25 on both U.S. and international best seller's list, published in 5 languages.
- **1996.** *Reengineering Systems Integration Success, Volumes 1 & 2.* Editor. ISBM: 1-8493-9952-1. (Auerbach, 1997- 1999).
- **1996.** *Step-by-Step Reengineering: The Comprehensive Guide to Process Change.* Author. ISBM: 0-8839-0476-4. (Jossey-Bass, 1996). This book was adopted by virtually every major consulting firm and has served as a foundation for many firms' proprietary methodologies. Also used by President Clinton & Vice President Al Gore in their "Reinventing Government," initiative. (1992-94). See, https://www.govexec.com/management/2013/04/what-reinvention-wrought/62836/
- Contributing author and/or editor to 3 other books (Auerbach) on process and system integration.

PAPERS BY MICHAEL MISCHE (partial)

- **2025.** *"A Study of California Gasoline Prices and The Potential Implications of The California Gasoline Reserve."* USC Business of Energy Transition Initiative (BET). (March 16, 2025).
- **2024.** *"Not All Oil is Created Equally: Understanding the Venezuela Petrostate."* USC Business of Energy Transition Initiative (BET). (September 2024).
- **2024.** *"Bidenomics…Facts, Figures and Everything Americans Should Know."* Co-authored with Torri Kyes. Over 40,000 reads as of September 1, 2024. (February 2024).
- **2024.** *"Is Venezuela the Answer to U.S. Oil Woes?"* USC Business of Energy Transition Initiative. (May 2024) (BET).
- **2024.** *"Understanding the Implications of Iranian Oil & U.S. Sanctions: What the Facts, Figures & Data Tell Us."* Oil & Gas Association. (April 2024).
- **2024.** *"2024 Management Consulting Annual Outlook."* Over 40,000 reads. (January 2024).
- **2024.** *"Management Consulting Annual Outlook & Firm Rankings: 2024."* Over 40,000 reads. (January 2024).
- 2023. *"The Fiction, Fallacy, Facts & Realities of California's Profit Gouging Tax."* (January 2023).
- 2023. *"When it Comes to Energy the Stupidity of Biden Administration Knows No End."* (Feb. 2023).
- 2023. *"Twenty-five Questions that all Americans Should Ask About Oil & Gas Prices."* Oil & Gas Association. (Oct. 2022).
- **Prior Papers: 1984 to 2022** (Partial List)
    - "Ranking the Top MBA Programs for Management Consulting." (2018, 2019, 2020, 2021).
    - "A Comparative Survey of Top Twenty MBA Management Consulting Programs." (2018).

- “Federal Tax Implications of Unclaimed Property,” (TAF, 2014).
- “Alternative Asset Class Investments: The Case for Classic Cars.” (SCG, 2013).
- “The Contagion Effect of Greek Default & It’s Impact on the Eurozone: A Working Paper,” (2013).
- “Innovation: The Engine of Strategic Renewal.” (Accenture, 1996).
- “Symptoms of a Terminally Ill Integration Project,” (Auerbach, 1997- 1999).
- “Transnational IT Architecture,” (Auerbach 1997- 1999).
- “Building Process Excellence: Lessons from The Leaders.” (The Economist/EIU, 1996).
- “Remedies to Wrongful Seizure: A Discussion of IRS Liens & Levies.” Jerome Horvitz and Michael Mische. (Warren Gorham & Lamont, 1984.)

EDUCATION

- **Massachusetts Institute of Technology,** Sloan School of Management. MA. (August 2020).
  - Certificate, Executive Education Program, AI: Implications for Business Strategy.
  - Modules completed included:
    - Introduction to AI
    - Machine Learning in Business
    - Natural Language Processing in Business
    - Robotics in Business
    - AI in Business and Society
    - The Future of AI

- **New York University**, Stern School of Business. NY, NY. (February 1978).
  - Master of Business Administration, Finance. Minor: Management.
  - Completed both BS & MBA is less than 5 years.
  - Thesis: “Business Cycles & Capital Investment Theory.” Advisor, Prof. Robert Kavesh, Chairman, NYU Economics Dept.
  - Honors Paper: “Price Level Adjusted Financial Statements.” Advisor, Prof. Barbara Marino.
  - NYU Graduate Assistant to Prof. Alexander Melamid & Prof. Rolf E. Wubbles.

- **Golden Gate University**, Graduate School of Taxation. San Francisco, CA. (June 1984)
  - Master of Science, Federal Taxation.
  - Publications: “Remedies to Wrongful Seizure.*”* (Warren, Gorham & Lamont. 1984).

- **New York University**, Stern School of Business. NY, NY. (October 1976).
  - Bachelor of Science, with Honors in Banking & Finance.
  - Double Major: Finance & Economics.
  - Minor: Political Science (Soviet Economic System).

- Honors Thesis: "Industry Analysis of Nonferrous Metals," Advisor, Prof. Rolf E. Wubbles.
- Five-year accelerated BS/MBA degree program (Awarded MBA at age of 23).
- Recipient: Jules Bachman & Boris Kostelanetz Academic Scholarships - Economics.
- Beta Gamma Sigma & Phi Alpha Kappa, national academic honors societies.
- Student Athlete. NYU Men's Varsity Swimming Team.
- Vice President, NYU Finance Society.
- Member, Phi Gamma Delta.

COMMUNITY SERVICE ACTIVITIES (Partial)

- Active in sexual assault prevention initiatives and counseling young men. (On-going.)
- Active financial supporter, LA Catholic Good Shepard Shelter for Battered & Abused Women. (On-going).
- Active financial supporter, USC Women's Basketball. (On-going).
- Active financial supporter, Phi Gamma Delta Educational Scholarship Fund. (1980 to present).
- Passionate supporter of Title IX initiatives for women athletics. (1977-present).
- Past Member, City of Pasadena, "We Must Breathe Task Force," for police reform and underrepresented economic opportunity programs. Chaired by the late Council Member, John J. Kennedy. (2020).

MISCELLANEOUS AWARDS (Partial)

- "Man, of the Year," elected by the NYU Chapter. (1992).
- Nominated for "Who's Who in America." (2001, 2024).
- Nominated for "Who's Who in American Business." (2011, 2024).
- "Most Influential Graduate Brother of the Year." (2023).

BOARD MEMBERSHIPS

- Due to the potential for conflicts of interest and publicity, Michael restricts his for-profit board affiliations to private organizations.
- Past non-profit board affiliations include, but are not limited to:
    - NYU-Stern, Annual Alumni Fund. Co-Chairman. (1990-91).
    - NYU-Stern, Haskins Fund. Board Member. (1992).
    - NYU-Stern, Dean's Advisory Board. Board Member. (1988-1992).
    - NYU-Stern, New Building Fund Board. Fundraiser. (1990-1992).
    - Phi Gamma Delta Educational Foundation. Board Member. (1990-1994).
    - Gamma Phi House Corporation. Board Member. (1990-2001).

PERSONAL INTERESTS

- Lifetime Member: International Fraternity of Phi Gamma Delta. Member. (1973 – present).
- Interesting Fact: Former elite-level two-sport athlete. (1969-1975).
- Passions: Classic American muscle cars, Formula 1 racing, writing, American military history, architecture, classical music, weightlifting, boxing, developing consulting talent, and PSU & USC football.
- Most notable influences: NYU Profs. Alexander Melamid, Rolf. E. Wubbels, Wassily Leontief (Nobel Recipient), & Ed Altman; KPMG Partners CEO Larry D. Horner & Hilliard M. Eure-III; my incredible athletic coaches & trainers; and most of all, my mother, Jane and father, Albert.

LINKS

- https://www.linkedin.com/in/michael-a-mische-987b30a/
- https://www.youtube.com/watch?v=dC5lLcSK-1I&t=13s
- https://www.youtube.com/watch?v=HvP2ELGHdjQ
- https://www.youtube.com/watch?v=2Rv7l2qhCSw&t=12s

PROOF OF SERVICE

I, Josie Cisneros, declare:

I am employed in the County of Los Angeles, State of California. I am over the age of 18 and not a party to the within action. My business address is Alston & Bird LLP, 350 South Grand Avenue, 51st Floor, Los Angeles, CA 90071.

On July 7, 2025, I served the document(s) described as **DECLARATION OF MICHAEL A. MISCHE IN SUPPORT OF REAL PARTIES' OPPOSITION TO PRELIMINARY INJUNCTION** on the interested parties in this action by enclosing the document(s) in a sealed envelope addressed as follows: *See* Attached Service List.

☒ BY ELECTRONIC MAIL TRANSMISSION WITH ATTACHMENT: On this date, I transmitted the above-mentioned document by electronic mail transmission with attachment to the parties at the electronic mail transmission address set forth on the attached service list.

☒ [State] I declare under penalty of perjury under the laws of the State of California that the above is true and correct.

Executed on July 7, 2025, at Los Angeles, California.

/s/ Josie Cisneros

Josie Cisneros

SERVICE LIST

Julie Teel Simmons, Esq. David Pettit, Esq. Talia Nimmer, Esq. Center for Biological Diversity 2011 Franklin Street, Suite 375 Oakland, CA 94612	ATTORNEYS FOR PETITIONERS CENTER FOR BIOLOGICAL DIVERSITY and WISHTOYO FOUNDATION Tel.: (510) 844-7100 Fax: (510) 844-7150 Email: jteelsimmonds@biologicaldiversity.org dpettit@biologicaldiversity.org tnimmer@biologicaldiversity.org
Linda Krop, Esq. Jeremy M. Frankel, Esq. Tara C. Regnifo, Esq. ENVIRONMENTAL DEFENSE CENTER 906 Garden Street Santa Barbara, CA 93101 Phone: (805) 963-1622; Fax: (805) 962-3152	ATTORNEYS FOR PETITIONERS 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 Tel.: (510) 844-7100 Fax: (510) 844-7150 Email: lkrop@environmentaldefensecenter.org jfrankel@environmentaldefensecenter.org trengifo@environmentaldefensecenter.org
Michael S. Dorsi, Esq. California Attorney General's Office 55 Golden Gate Ave, Ste 11000, San Francisco, CA 94102	ATTORNEYS FOR RESPONDENTS/ DEFENDANTS California Department of Forestry and Fire Protection, Office of the State Fire Marshal; Daniel Berlant, in his official capacity as State Fire Marshal Tel.: (415) 510-3802 Email: Michael.dorsi@doj.ca.gov
Duncan Joseph Moore, Esq. Benjamin J. Hanelin, Esq. Natalie C. Rogers, Esq. PAUL HASTINGS LLP 1999 Avenue of the Stars, 27th Floor Century City, California, 90067	ATTORNEYS FOR REAL PARTIES IN INTEREST Sable Offshore Corp.; Pacific Pipeline Company Tel.: (310) 620-5879 Email: djmoore@paulhastings.com benjaminhanelin@paulhastings.com natalierogers@paulhastings.com
Trevor D. Large, Esq. FAUVER, LARGE, ARCHBALD & SPRAY LLP 820 State Street, 4th Floor Santa Barbara, CA 93101	ATTORNEYS FOR REAL PARTIES IN INTEREST Sable Offshore Corp.; Pacific Pipeline Company Tel.: (805) 966-7000 Email: TLarge@FLASllp.com

Attachment D:
S. Ellis, M. Mische, M. Ariza, "California Energy & Fuel Policies: A Clear and Present Threat to National Security and Force Readiness" (Oct. 21, 2025)

Not Classified. For Discussion Purposes Only

CALIFORNIA ENERGY & FUEL POLICIES: A CLEAR AND PRESENT THREAT TO NATIONAL SECURITY AND FORCE READINESS?

by

Stan Ellis, Member, California Assembly (1)

Michael Mische, University of Southern California (1)

Michael Ariza, Petroleum Professional & U.S. Navy Veteran (1)

Released October 21, 2025

Washington, D.C.

1600 Hours

EXECUTIVE SUMMARY

The purpose of this paper was to research and discuss the influence of California oil, fuels, and refining regulatory policies, statutory actions, and prevailing political attitudes on U.S. military force readiness and national security. Our analysis has identified and addressed **four** major points of California created and specific vulnerabilities which can compromise U.S. military force readiness and national security: 1- Refineries, 2- Distribution (Pipelines), 3- Production, and 4- Fuel Inventories.

1.0 Introduction

Arguably, California has the most severe restrictions regulating the oil, refining, and fuels industries in the world. California's energy policies and regulations have not only resulted in the highest gasoline prices in the nation, and the highest taxes and fees in the nation but have led to the closure of two major refineries which now threaten essential pipelines that provide crude oil and fuel supplies to California's surviving refineries, civilian markets, and military installations, as well as those in Arizona and Neveda.

The oil and gasoline industries in California account for around 8% of the state's GDP…but it is, critically, the first 8% of its overall GDP. Without oil and gasoline, the other 92% would be impossible to attain. Without petroleum, asphalt can't be made, and steel cannot be produced. Even in a state as environmentally conscious as California, fossil fuels still generate around 40% of all electricity. Without that 40%, there would be no Silicon Valley. Without gasoline and diesel fuels, California agricultural production would be a fraction of what it is today.

California was once a leading producer and exporter of oil and crude oil products in the world. Much of California's 20th-century economy was predicated on oil and gasoline production, which, in turn, provided the fuel to support its population growth, agricultural production, the defense industry, and later, the tech industries. Today, California is far from self-sufficient with respect to its energy needs. The state produces less than 23% of its own in-state petroleum needs, and imports over 65% of its crude oil from non-U.S. foreign sources, the largest of which was Iraq over the recent years.

As a result of California government policies and regulatory actions, as well as years of politicians demonizing refiners and producers as "price gougers" without economic proof, California is now facing a pending gasoline and aviation fuels crisis of potentially epic levels. In all planning scenarios, California will be increasingly dependent on non-U.S. foreign sources for gasoline. Rather than investing in its state's resources and employment, California's policies necessitate paying petrostates, such as Iraq and Saudi Arabia, over $60 million a day for crude oil imports. In addition to buying crude oil, the Golden State will now be paying for non-U.S. foreign gasoline, some of which may be made from Iranian and Russian oil. In this regard, and as a direct result of its political and regulatory policies, California will be knowingly financing and, perhaps to some extent, aiding and abetting America's potentially most menacing adversaries.

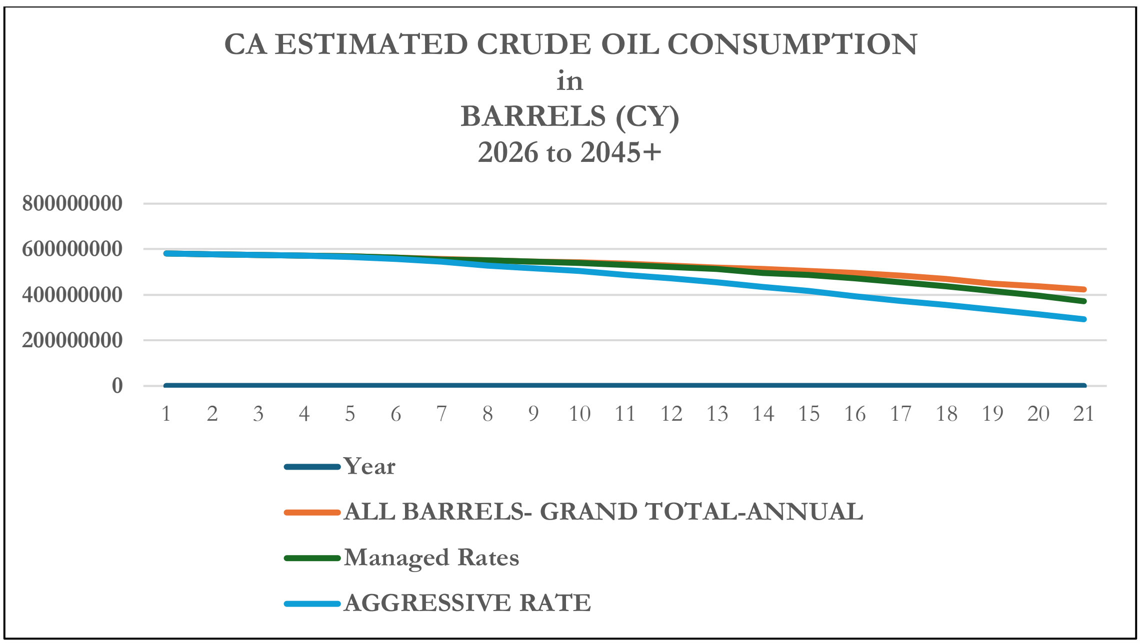
In our collective opinion, and after considerable study, we believe that California's policies as well as its recent demonstrated inability to effectively manage the current refinery closings and in-state oil production crisis contributes to increased vulnerabilities to military fuels disruption which, in turn, can compromise U.S. force readiness and national security.

2.0 California Oil & Gasoline Consumption

California consumes around 580 to 603 million barrels or 25 to 31 billion gallons of crude oil products annually. Of that amount, approximately 97.6 million barrels of crude or 16% is associated with aviation (jet fuel) consumption. Of the 97.6 million barrels of jet fuel consumed in 2024, around 10.0 million gallons are associated with "normal" military aviation. In times of military actions or national defense, that consumption is likely to be far higher…and California must have resiliency and redundancy in-situ; it does not. California refineries also produce aviation gasoline, commercial aviation fuel, diesel fuels, and gasoline for military consumption. As demonstrated in Operations Desert Shield and Desert Storm, military mobilization often involves personnel and material movement via commercial airliners and chartered flights, which use aviation jet fuel.

Despite having the 5th largest crude reserves in the U.S., California's in-state crude oil production has fallen over 68% since 1991. Consequently, California is the most heavily reliant of all U.S. states on non-U.S. crude oil sources, with non-U.S. oil imports comprising over 65% of California's needs. In 1981, California's imports from non-U.S. countries were less than 6%. While overall U.S. dependency on foreign oil has declined dramatically, California's dependency has increased. That overdependency on foreign oil providers and foreign-flagged oil tankers contributes to U.S. military readiness concerns, as well as the potential for compromised national security.

Overall gasoline consumption in California, despite political hyperbole surrounding EV adoption, has not materially changed since 2001. In fact, it's less than one percent annually. EV adoption rates have slowed and are far below the projections of the California Air Resources Board (CARB). Californians consumed over 317 million barrels of gasoline in 2024. Furthermore, California supplies 88% of its gasoline needs to Nevada and 33% of its needs to Arizona, or around 44.9 million barrels of gasoline annually. Furthermore, the largest growing segment of fuel consumption in California is jet fuel. As California is losing refinery capacity and, quite possibly, pipelines due to low volumes, California's energy policies and attitudes towards its oil, gas, and refinery operators creates force readiness concerns and potential conflicts in resource allocations.

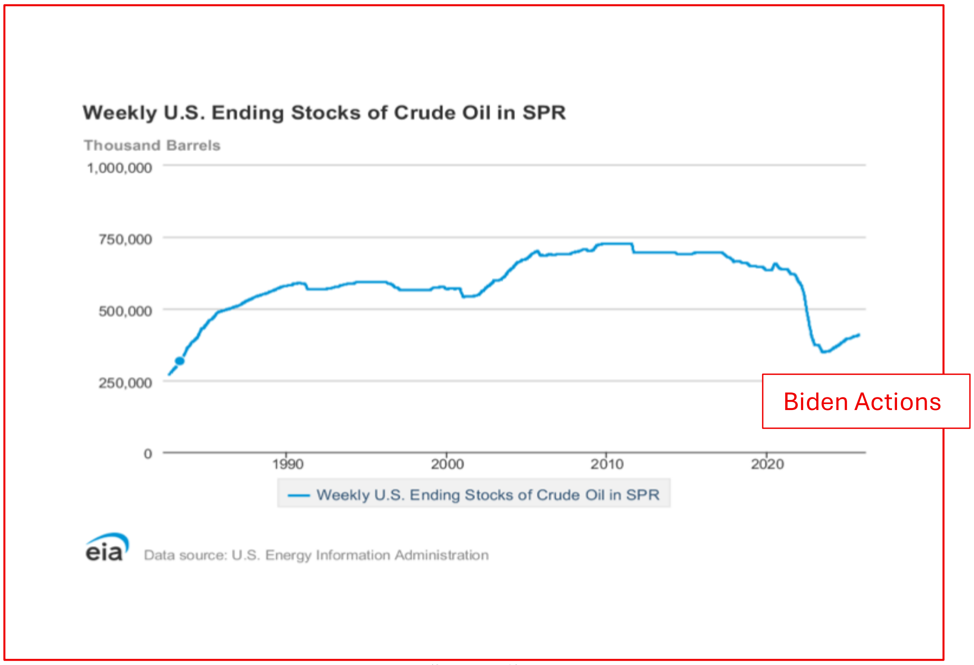


Source: M. A. Mische

3.0 California Refineries

Military aviation fuels are of the highest grades and standards and require specialized refining operations. F-18, F-22, and F-35 fighter jets, heavy bombers such as the B-52, B-1, and B-2, and drones all rely on advanced aviation jet fuels. When deployed in combat or on routine missions, America's war fighters require fuel. The logistics of resupply require precision planning and operations of the highest caliber. U.S. aircraft carriers, which exist for the sole purpose of launching military aircraft, must carry millions of gallons of jet and aviation fuels for the performance of their mission. California oil refineries and pipelines are the fountainhead of a long and complex military fuels supply chain. Any operational or policy failure along the logistical supply chain can and will compromise operations, the mission, and American lives.

Neither the U.S. nor California government own and operate oil fields or refineries. Contrary to common belief, the U.S. Strategic Petroleum Reserve (SPR), which was created in the 1970s and is located predominantly in America's southeast, does not store gasoline or jet fuels. The SPR stores crude oil. Alarmingly, the SPR, under President Joe Biden, was drained of crude, with days' supply plummeting 62% from 12/25/20 to 12/27/24.

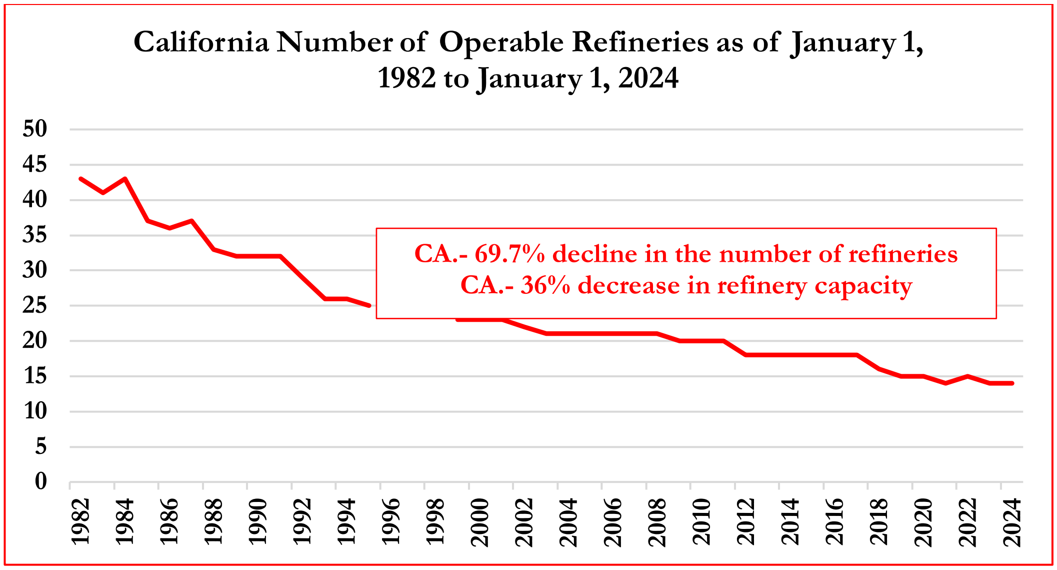


(Source: EIA)

Despite being the largest state in the Union and the 4th largest economy in the world, California has no inbound pipelines supplying crude oil, gasoline, or aviation fuels, which amplifies U.S. national security vulnerabilities. Astonishingly, over 95% of California's inbound crude and gasoline supplies are delivered by maritime tankers, the majority of which are not U.S.-flagged vessels, including tanker ships owned by Russia's SCF Group and China's Cosco Shipping Energy Transportation.

In 1991, there were over 40 refineries in California. As of October 16, 2025, there are eight refineries operating in California with a combined processing capacity of 1.467 million barrels of crude oil daily. That's down 68% in the number of refineries since 1991. As Chevron President Andy Walz recently noted in a Fox Business interview, "I think it's been a tyranny of about 25 years to get the refining business to leave California." Consequently, it was not, as some California politicians and agency "experts" assert, that it was by intentional desire or some industry conspiracy that created industry concentration and reduced the number of refineries in the state; it was state regulations and policies that drove the refiners out.

By April 2026, there will only be seven refineries surviving in California as a result of the two most recent refinery closures (Phillips 66 and Valero). In-state gasoline production will be reduced by at least 6.2 million gallons a day, with progressively worse-case estimates totaling 9.33 million gallons a day. In addition, jet fuel production from Valero will drop by 600,000 gallons a day. By 2035, California refinery production could decline by 35% or more, placing greater pressure on shrinking supplies, increasing consumer prices past $8.00 a gallon, and forcing greater dependency on non-U.S. suppliers for fuels and crude oils and foreign shippers.



Source: EIA & CEC

4.0 California: America's Asia-Pacific Military Vanguard

Since 1945, U.S. military doctrine has been founded on deterrence and "Peace Through Strength." California's military installations sit as the vanguard of U.S. forces with direct facing to potential nuclear adversaries such as North Korea, Russia, and the People's Republic of China (PRC), and transnational terrorist organizations in the Philippines, Malysia, and Middle East. California is home to some 50-plus U.S. military installations, which include, but are not limited to:

- The Pacific Fleet based in San Diego, Alameda, and Point Loma.
- United States Marines stationed at Camp Pendleton, Twenty-Nine Palms, Miramar, and Barstow.
- U.S. Coast Guard ports and stations located inland and along the state's 840-mile coastline, and from bases inland.
- U.S. Air Force bases, including Los Angeles, Edwards and Travis and missile bases such as Vandenberg.
- The U.S. Navy Post-Graduate College located in Monterey.

California's refinery capabilities extend to provide fuels to U.S. bases located in Arizona and Nevada. For example, California supplies Luke Air Force base, the USMC base in Yuma, and the Air National Guard based in Arizona. California also supplies fuels to Nellis and Clark Air Force bases in Nevada, as well as military testing, proving, and training areas, which are essential for war readiness, and are also located in Arizona and Nevada.

California-based military forces are under the command of U.S. Indo-Pacific Command (USINDOPACOM) and are capable of providing lethal forces, at strength and scale, as needed, anywhere in the world within 72 hours…assuming, of course, that those forces have sufficient fuel to reach the designated theaters and threats and can prosecute continuous war operations. To help put the U.S. commitment to the Asia-Pacific Theater, two of the largest U.S. military installations are located in Japan and South Korea. Total U.S. troop strength in the Asia-Pacific Command deployed to Japan and South Korea outnumbers that of Europe.

California's energy policies, political sentiments, and regulatory environment have become a direct threat to U.S. military force readiness on the West Coast. As has been documented in various U.S. war planning exercises and studies, America confronts a new axis of evil composed of China, Iran, North Korea, and Russia. These potential adversaries, along with the emergence of transglobal terrorism have presented the U.S. the considerable challenges for both 2.5 and 4+1 war planning scenarios. However, with diminishing refining capacity placing pressures on supply, and extreme reliance on non-U.S. crude and gasoline, as well as foreign tankers for supplies, California's policies appear not to align with nor support the concept of self-sufficiency, and the need for force readiness.

In any conflict scenario, U.S. force readiness and response plans require jet, diesel, and gasoline to prosecute war operations. As the vanguard to the Asia-Pacific Theater, the weight of U.S. Pacific readiness stands squarely on the shoulders of California and its refineries and gas and oil infrastructure. Given the current status and trajectory of California energy policy, it is not an issue of whether military fuel supplies will fail; that process has already begun. The larger and more concerning issue is that if left unaddressed, and if left to the whims of the California Legislature and the wisdom of Governor Newsom, California's apparent failure to fully comprehend and effectively address the current oil and gasoline crisis will only accelerate fuel, price, and supply insecurities, which could ultimately, compromise U.S. military force readiness and U.S. war doctrine.

Under Defense Fuel Support Point (DFSP) cover levels, as verified in DLA Energy Logistics Manual (3–5 days peacetime working stock and faster under surge demand), Pacific readiness begins degrading within ~72 hours. DFPS, which maintains only minimal day's supplies of fuel stocks, acquires its fuel from commercial refineries owned and operated by for-profit corporations and predominantly uses commercially available pipelines for the delivery of its fuel supplies. In practical terms, this means that if fuel deliveries stop, California and its neighbors begin running dry almost immediately, imperiling both civilian mobility and military operations.

The collective effect of California's policies and regulations has created vulnerabilities to America's war readiness, which are, undoubtedly, well-studied and well-known to our adversaries. California's central role in National Defense extends beyond its borders and neighboring states. For example, the closure of the Red Hill Bulk Fuel Storage Facility in Hawaii eliminated the Pacific's only hardened strategic reserve, forcing the U.S Indo-Pacific Command to adopt a dispersed fuel posture. Fuel once stored under a mountain at Red Hill is now distributed among new and expanded bulk sites in Australia (Darwin ~ 80 million gallons), Guam, Japan, Korea, and the Philippines. While this distributed model improves survivability, it multiplies dependence on California's refinery output and tanker lift capacity to sustain forward forces. Analysts estimate that roughly 86 tankers would be required to maintain continuous supply during a major Pacific contingency; several dozen more than the U.S. fleet now controls. Every gallon that fails to leave California on schedule compresses the ~72-hour readiness window described in this report. In effect, California's fuel network is not just a state vulnerability; it is the starting point of America's forward defense posture, and its failure would ripple through every Pacific operational node within days.

Other than increasing reliance on oil and gasoline from non-U.S. suppliers and foreign-owned tankers for transport, California's government and leadership have no real plan to address its pending gasoline and aviation fuels crisis. More importantly, California leadership has woefully underestimated the implications of its actions on overall U.S. national security. For example:

- The Phillips 66 Rodeo refinery, formerly a 120 kbpd crude facility, has already transitioned to renewable diesel and no longer contributes CARB-compliant gasoline or jet fuel to the state supply. With no local reserves and only working stocks at DFSPs, every disruption must be absorbed in real time by an already strained supply chain.

- Recent incidents further illustrate the magnitude of capacity attrition. PBF Martinez sustained a maintenance fire on February 1, 2025, forcing the refinery offline until late April. It did not return to full restoration until the third quarter of 2025.

- Marathon Martinez, a 161,000 BPD refinery, was idled by a fire on November 19, 2023, and has yet to resume full crude operations and continues producing about 17,000 BPD of renewable diesel, effectively removing roughly 160,000 BPD of crude-mode capacity from the state's system.

EIA data indicates that California and the broader West Coast have no strategic refined-fuel reserve. At any given time, the total volume of transportation fuel in transit or storage across the region equals only about two to three weeks of normal demand—roughly fourteen to twenty-one days of supply. In a national emergency, the federal government could requisition commercial fuel stocks for military-priority use, but without active resupply, even those operational reserves would be exhausted within roughly two weeks. Replenishment would rely on long-distance imports that take additional weeks to arrive, especially as in-state production continues to shrink.

The U.S. military consumes over an estimated 100 million barrels of oil annually. The U.S. Air Force is the largest consumer of crude among the branches…Navy is second and Marines are third. To help put military consumption in perspective, according to various estimates, the USS Ronald Reagan, a Nimitz-class carrier, which posts F/A-18 Super Hornets airwings and other aircraft, maintains at least 3.4 million gallons of jet fuel as inventory to support airwing operations. An F/A-18 fighter jet carrier-based airwing is composed of 35 to 43 aircraft and consumes up to 800,000 gallons a day if operating in combat conditions and depending on fuel density and aircraft efficiencies. A single F/A-18 Super Hornet alone can burn upwards of 1,100 gallons per hour and around 72,000 pounds per hour with full afterburners. A 2020 analysis of F/A-18F fuel consumption based on over 400,000 sorties indicated that the average fuel consumption for Asia-Pacific is 13,396.9 lbs. per sortie or about 2,000 gallons. The U.S. Air Force's B-2 bomber holds 172,000 lbs. of fuel and burns 3,300 lbs. per hour, and America's "The Bone" B-1 supersonic bomber carries 265,274 lbs. For comparative purposes, a Boeing 747-Bi used for commercial flight and charter transport of military personnel carries around 63,000 lbs. of fuel.

5.0 California Pipelines

California has an extensive network of pipelines <u>within</u> the state. However, California's gasoline dilemma is further exasperated by the absence of any <u>inbound</u> pipelines from other states for oil or gasoline. As a result, California is isolated and has become increasingly dependent on foreign oil imported mostly by large maritime tankers and, to a lesser extent, rail and truck transports. Consequently, 98% of all foreign-sourced inbound crude oil is supplied to California via maritime vessels. The lack of inbound pipelines from other states isolates California from U.S. and Canadian sources and places the State in a vulnerable position with respect to oil and gasoline supplies.

California's immediate concern is related to its major northbound pipeline which has a capacity of around 300,000 barrels of throughput daily. Since assuming office in January 2019, new oil drilling permits under Governor Newsom fell by 95%. The reduction in new drilling permits and California's long-standing policies, which have crippled California's in-state onshore oil production and have prohibited offshore producers from using existing pipelines to move production onshore, the northbound pipelines are susceptible to imminent closure as they require 90,000 barrels a day in production to remain operationally and economically viable. Currently, they are operating at around 17% of capacity or 50,000 barrels a day, and the owner/operators are experiencing financial losses of around $2.0 million a month. In reaction, California passed SB 237, which is intended to provide additional in-state oil production from Kern County, ostensibly to address the potential of pipeline closures. Initial research indicates that SB 237 alone will not provide sufficient production to meet California's needs, and at prevailing lower Brent crude prices, it is questionable whether any new production will come online in time to make the northbound pipeline system economically sustainable. Stated differently, SB 237 still leaves California short in in-state oil production.

The closure of the northbound pipelines presents a direct threat to U.S. force readiness and represents a profound vulnerability in national security. For example, a technical weakness in California's fuel network directly translates into a potential military vulnerability. If a major pipeline or terminal disruption halts deliveries of JP-8 jet fuel or diesel to regional bases, the ability of U.S. forces to project power is immediately constrained. Fighter and transport aircraft cannot launch, and Army or Marine convoys cannot deploy without JP-5, JP-8, or diesel in their tanks. The interdependence is absolute: every service branch operating in the western United States relies on the same California-linked logistics chain for refined fuels, and any disruption or interruption can compromise military mission readiness.

<u>For any Asia-Pacific operation, California's refinery and in-state oil production will be essential to the fighting effectiveness of U.S. forces, and any further losses will compromise U.S. force readiness</u>. To compensate for California's actions, the American Taxpayer will have to pay additional costs and fees to acquire, transport, and store the fuels that were once produced in California. As it currently stands, California has lost a significant portion of its gasoline production from the October 16, 2025, closure of the Los Angeles area Phillips 66 refinery. In addition, California will lose another 145,000 barrels a day of production with the closure of the Valero refinery in Northern California. Between 2023 and April 2025, California refinery production will have cumulatively dropped

by almost 22%. Any further loss in in-state oil production will most likely result in the loss of the north-south pipeline system. The loss of the pipelines will necessitate hundreds of additional trucks to be used on California's roads to transport both crude oil and fuels predominantly to the few surviving northern refineries. Although the roads may be able to accommodate massive increases in the volume of truck traffic, the originating and receiving ports for the transported cargo have physical limitations, and road blockages, accidents, and equipment failures, will create the inevitable back-ups and delays in supplies. In the event of military mobilization, at any scale, those self-imposed California limitations will become liabilities.

Travis Air Force Base provides a simple hypothetical example of how reduced refinery capacity and pipeline disruption can influence readiness risk. The base's resupply threshold triggers when on-hand inventory falls below roughly 8–9 million gallons, at which point Valero dispatches a jet-fuel batch from Benicia. The refinery maintains three jet-fuel storage tanks totaling about 290,000 barrels (~ 12.2 million gallons). During standard peacetime operations, Travis issues around 200,000 gallons per day, equivalent to roughly one week of cover. Under surge or contingency conditions, when heavy- lift and tanker sorties increase sharply, that stock would last fewer than three days. For example, during mobilization and extensive operations, tanker sorties increase sharply, thereby increasing overall Travis consumption to over 1.0 million gallons per day or less than three days of fuel supplies in on-hand inventory.

Travis receives its jet fuel from a private pipeline from a northern California refinery, predominantly Valero. The disruption of the pipeline and/or the closure of the refinery supplying the base would require replenishment, most likely by truck. Based on approved capacities, that would require approximately 21 trucks per day, seven days a week, 365 days a year, just to compensate for equivalent amounts lost due to refinery and pipeline closures. Looking at it differently and assuming that California will lose more refineries, and or lose the major north-south pipeline system, which has a capacity of around 300,000 barrels a day, the state would require an additional <u>1,333 tanker trucks per day</u> to transport fuels and crude oil. California's road system, bridges, and loading and receiving terminals would be overloaded and flooded with traffic and incapable of processing such volume on a daily basis. Using railroad tankers would require at least 44 more cars per day, which would still need truck support.

6.0 War Planning: Understanding The Stress Case (Multi-Point Failure

War planning is a complex and sophisticated process. Multiple scenarios and an endless list of permutations and combinations are possible. For purposes of this study, we focused on a "worst-case" scenario involving multi-point failures. Specifically, and for example and discussion purposes only, a concurrent disruption, such as a major refinery casualty combined with a CalNev/SFPP East pipeline shutdown and temporary marine-terminal outage, would eliminate 70–90 percent of refined-product inflow across California and the interior Southwest for at least one week.

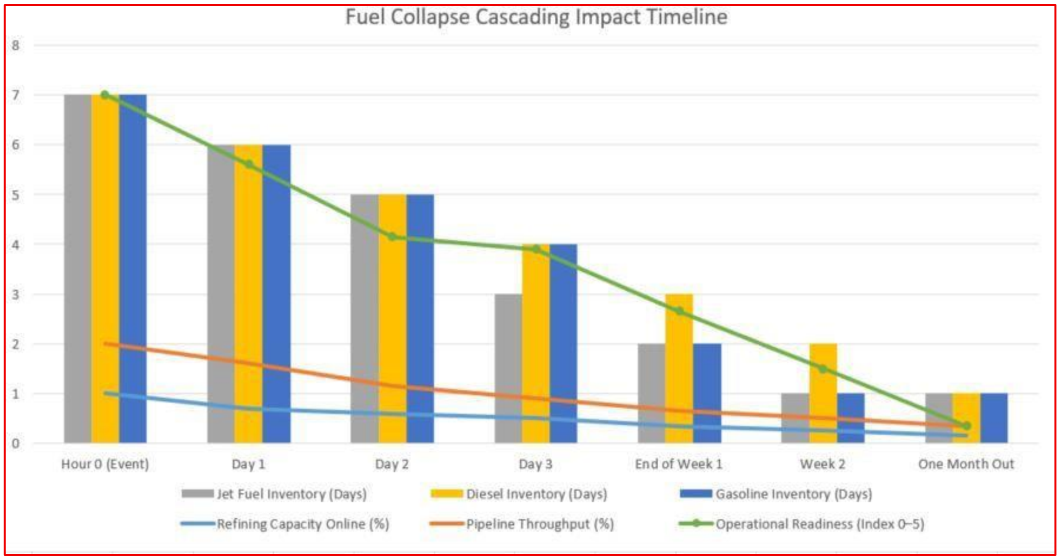
- Day 1: Within the first 24 hours, refineries and terminals exhaust operational buffers and activate allocation orders. DFSPs suspend all non-mission fuel activity and re-route limited deliveries to priority installations.

- Days 2 & 3: Regional airports, including LAX and Phoenix, begin rationing jet fuel; interior corridors such as Las Vegas approach critical supply. Retail shortages expand rapidly, forcing fuel-priority declarations for emergency services.

- Days 4 to 7: Routine flight training ceases entirely to preserve JP-8/JP-5, hospitals and water utilities will near diesel exhaustion, and consumer panic drives queueing and sporadic unrest.

Without rapid restoration, regional readiness degrades sharply by the end of the first week. The initial marine backfill arrives only after three to six weeks (average Asia–California voyage plus terminal delay), confirming that import cadence cannot stabilize inventories before collapse. Under this stress test, a two- to four-week period of severe operational degradation emerges—a pattern consistent with DOE CESER and RAND interdependency models and observed colonial-scale disruptions. While the probability of simultaneous multi-node failure is low, correlation rises sharply under major seismic events, coordinated cyber intrusion, or deliberate sabotage. This scenario, therefore, defines the upper bound of regional vulnerability and validates the trigger thresholds established in Eq. E10 (days-of-supply < 5, pipeline outage > 24 hours, or refinery unit loss > 40 kbpd) are the points at which immediate federal allocation, waiver, and unified-command actions must initiate.

The chart below illustrates the sequential decline of refining capacity, pipeline throughput, and fuel inventories following a multi-node outage. As illustrated, jet fuel would collapse first, which would reduce operational readiness within 72 hours. By Week 2, operational readiness falls below 40% of baseline, confirming that cascading logistics failures drive exponential loss of capability and are not linear. In this scenario, the loss will most likely accelerate, exasperating U.S. operational efficacy.



Source: Eq. E1 (Inventory with Transport Lags), Eq. E9 (Economic Loss from Shortages); EIA PADD 5 2024; CEC Petroleum Watch 2024; DLA Energy Dat

7.0. Call for Presidential Action & Immediate Relief

Californians pay the highest gasoline prices and are burdened with the highest taxes and environmental program costs in the nation. Consequently, California consumers suffer at the pump. Furthermore, California, through its history of legislative actions and the consequential implications leading to the loss of in-state oil production, pipeline capacities, and refinery losses, has demonstrated its incapability to recognize and inability to preserve the national security interests of the nation, as well as the economic interests of neighboring states, with respect to energy production.

Although it was not the objective of this paper to determine the legal and political remedies to the California energy crisis and its contagion effect on the broader national interests, there are some intuitive actions that may provide POTUS with several options to mitigate the actions of California and protect the security interests of the U.S. as related to California as related to petroleum and refinery assets.

The most direct method may be for POTUS to declare California oil production pipelines, terminals, ports, refineries, and all related infrastructure as essential assets and invoke the Defense Protection Act (DPA) as provided under DPA Titles I and III, and DoD (now DoW) Directive 3020.40. This would have the effect of allowing POTUS to preserve and protect California oil production and refining assets essential to national defense. Secondly, POTUS may be able to avail himself of the national Emergencies Act to provide temporary relief to California producers, operators, and refiners. Finally, as a critical and essential national security asset, POTUS may have constitutional powers for protecting California gasoline production and other petroleum assets, potentially through operation of the Supremacy Clause of the U.S. Constitution.

California and the nation can ill afford a self-engineered and created California gasoline and aviation fuel crisis. Both the economic and national security interests are profoundly influenced, and sadly, compromised by California's political sentiment and legislative actions related to refinery operations and oil production.

The need for action is now, and the potential for a crisis caused by California's selfish policies creating a contagion effect on U.S. force readiness is imminent. It's time for Presidential intervention and national oversight.

For Additional Information, please contact:

Mr. Stan Ellis, Member of the California Assembly
Email: sellis@bak.rr.com

Professor Michael Mische, University of Southern California
Email: mische@marshall.usc.edu

<End of document>

Attachment E:
J. Silvi, J. Rector, M. Mische, "A Study of SB 237 to Stabilize Oil Production in California"

A STUDY OF SB 237 TO STABILIZE OIL PRODUCTION IN CALIFORNIA

Joseph B. Silvi
University of California, Berkeley

James W. Rector
University of California, Berkeley

Michael A. Mische
University of Southern California

Disclaimer & Statement of Independence

This paper solely represents the independent work, analysis, perspectives, representations, and opinions of the authors. It does not, in any manner, explicitly or implicitly, reflect, represent, or describe the views, opinions, policies, and positions of the University of California, or the University of Southern California, and their respective faculty, employees, administration, or students.

In creating and presenting this work, the authors have made all reasonable attempts to ensure the accuracy and consistency of the data, attribution to data sources, analysis, and calculations. Nonetheless, variances in data and presentation may exist to some degree. In the authors' opinion, such variances will not materially change the tenor, trajectories, impressions, interpretations, conclusions, or possible implications associated with the data, data sources, and related analysis.

The work presented herein is provided for informational, research, discussion, policy, and educational purposes. In performing this work, the authors have not received any special compensation and have no promise or anticipation of any compensation for the work presented herein. This work and the authors are entirely independent and not affiliated with, in any form, and are not advocating on behalf of or representing any petroleum company, organization, or foreign entity.

Data Sources and Methods

For this research effort, a series of critical questions were developed, and data related to addressing those critical questions were identified, obtained, organized, and analyzed. The research involved in this work is widely available and includes but is not limited to verifiable sources such the California Energy Commission, U.S. Energy Information Agency, Bloomberg, U.S. Department of Energy, SEC filings, International Energy Agency, Oil & Gas Journal, American Petroleum Institute, the California Department of Tax and Fee Administration, the U.S. EPA, California Air Resources Board, Statista, California Attorney General's Office, California Legislative Analyst's Office, U.S. Department of Interior, Bureau of Labor Statistics, California DMV, California Geologic Energy Management Division, and the U.S. Oil and Gas Association. Readers are strongly encouraged to avail themselves to the many sources and authorities footnoted herein.

A STUDY OF SB 237 TO STABILIZE OIL PRODUCTION IN CALIFORNIA

TABLE OF CONTENTS

1.0 Executive Summary

The objective of this paper was to examine the potential implications of SB 237 in the broader context of California's refinery closures, oil and gasoline consumption, imports, pipeline capacities, product imports, and environmental impacts.

At one time, California was the leading producer of crude oil in the world, yet today, the Golden State is facing a potential gasoline supply crisis. Long-standing policies and an adverse political and regulatory attitude have resulted in a steady reduction in both California's in-state oil production and refinery capacity, leading to increased dependency on oil and, potentially, more gasoline from foreign sources, such as Iraq, Ecuador, Brazil, and, at times, Russia, Iran, and Venezuela. Already saddled with the highest regulatory costs and taxes in the nation, retail gasoline prices in California are over 50% higher than the U.S. average.[1] [2] With the imminent closure of two refineries and the loss of at least 20% of its in-state refinery capacity to produce gasoline, or around 6.5 million gallons a day, as well as the potential loss of California's largest inland pipeline which supplies crude oil to Northern California, California could be confronting double-digit gasoline price increases, and worse, gasoline shortages and lines at the pump.

In response to the growing potential crisis, Governor Newsom and the California Legislature reversed years of anti-oil policy and passed SB 237. In a stunning contradiction to the stated viewpoint that <u>"increasing CA oil production will not change gasoline production capacity and may only marginally change production costs,"</u>[3] SB 237 was enacted and signed by the Governor with the intent of allowing up to 2,000 new oil drilling permits annually within Kern County as the means to increase California's oil production and stabilize its pipeline and refining infrastructure. However, while this policy change is well-intentioned, it is likely <u>not sufficient</u> to stabilize the state's pipeline and refining infrastructure.

Moreover, while SB 237 attempts to address production and supply concerns, California's energy policy must also consider climate impacts, environmental protection, and social justice. Producing crude oil in-state must meet the most rigorous environmental standards in the world and is subject to emissions mitigation programs, reducing methane, volatile organic compounds (VOCs), and other pollutants compared with production in countries with weaker oversight. Local production can also help reduce toxic emissions from natural oil and gas seeps, which are a significant source of methane and air pollution in regions like the Los Angeles Basin and Santa Barbara Channel. By capturing and responsibly managing these emissions, California can improve air quality, protect community health, and limit environmental degradation. Conversely, relying on foreign crude transfers environmental and social impacts overseas and can increase global greenhouse gas emissions, pollution, and environmental destruction. By prioritizing responsible in-state production alongside careful regulatory oversight, California can strengthen energy security, reduce both local and global pollution, bolster its economy, and serve as a model for balancing economic, environmental, and social priorities.

---

[1] CA's regulatory costs, including taxes, are around $1.44 a gallon or about 30% of today's AAA price of gas of $4.655.
[2] https://gasprices.aaa.com/state-gas-price-averages/
[3] Brandon Richards, Deputy Director, Office of the Governor, State of California, May 7, 2025.

1.1 Findings

Using data from the California Energy Commission (CEC), the California Geologic Energy Management Division (CalGEM), the U.S. Energy Information Administration (EIA), California Department of Tax and Fee Administration (CDFTA) and other public and validated sources, the authors performed multiple analyses and built several complex models. Our findings indicate:

1. California requires around 578,000,000 to 581,000,000 barrels of crude oil-derived transportation fuels and products (such as road asphalt) annually to support its economy and to partially supply neighboring states with said fuels and products.

2. California's consumption of crude oil and gasoline has declined moderately but not significantly over the 2001 to 2024 period. The annual rate of decline has averaged less than one percent, and consumption has increased by nearly 7% since the all-time low in 2021 during the pandemic. The 2001 to 2024 decline trend is consistent with the observations of Stillwater Associates.

3. There is no indication that the consumption of gasoline and other transportation fuels in California will decline at any significant rate for the foreseeable future. Note, California's fastest growing fuel segment is aviation jet fuel.

4. Since 2001, the number of California refineries producing California compliant gasoline has fallen by almost 70%, inclusive of planned closures of two major refineries.

5. California's in-state oil refinery capacity for producing California fuels will have declined by 21% from 2023 to 2026, resulting in a net loss of 6.2 million gallons of in-state produced gasoline per day. It would be unrealistic to expect that demand will fall by that amount by April 2026 when the Valero refinery in the San Francisco Bay Area is set to shut down.

6. Based on CEC data, California sourced crude supplies (in-state production) have declined by 65.3% from 2001 to 2024, while dependency on foreign oil has increased by 69% for the same period to over 324 million barrels per year.

7. The passing of SB 237 and the drilling of new wells in Kern County will add an estimated 10,125 barrels of oil per day (bopd) each year through 2030. However, California's statewide oil production is currently declining at a rate of about 18,000 bopd annually, meaning that even with SB 237, **California production will still experience an annual decline at the rate of approximately 7,875 bopd**.

8. The only way to stabilize in-state production is to drill and produce oil in other parts of California in addition to Kern County such as the Santa Barbara Channel and the Los Angeles Basin (LA Basin) which have several billion barrels of recoverable oil resources. These actions, along with a return to historical procedures for well operations and oil producers by CalGEM, can stabilize in-state production and prices while reducing highly pollutive foreign oil imports.

9. SB 237 could partially support the continuing operation of the in-state northbound pipeline system. Based on our estimates of SB 237 production, with an estimated pipeline capacity of 300,000 bopd, and a minimum of 30% capacity utilization required for operational and financial breakeven (90,000 bopd).

10. The demand for the northbound pipeline complex capacity (300,000 bopd) will be reduced by the closure of the Valero refinery and the loss of 149,000 barrels of daily refining capacity.

1.2 Conclusions

The additional wells allowed under SB 237 will not stabilize in-state production, and as a result, in-state production will continue to decline as it is more than likely that producers will not drill 2,000 wells annually. Thus, it will not sufficiently address California's crude oil and gasoline needs and will not provide the much-needed stabilization of production to ensure California's oil and gas infrastructure and energy security in the near and midterm. The only way to stabilize production is to allow drilling in other regions of California like the LA Basin and the Santa Barbara Channel alongside minor, practical changes to regulations and policies which are restricting in-state production.

Furthermore, due to the imminent loss of two and potentially up to four refineries, California will be increasingly dependent on foreign sourced gasoline from suppliers such as India, South Korea, Saudi Arabia, Singapore, and, perhaps, China. India receives 40% of its crude oil from Russia, while China receives a significant portion of its crude stock for gasoline from Iran, Russia, and Venezuela.

Irrespective of SB 237, and as a consequence of market factors, California regulatory and political policies, the naturally occurring declines in crude oil production and significantly diminished refinery capacities, California will need to import gasoline from foreign sources. Therefore, we anticipate significant increases in fuel prices based on various crude oil price assumptions and supply stability.

For the foreseeable 20-year future and based on current estimates, economic and political assumptions and crude oil prices, a realistic estimate of the California's total crude oil demand indicates that it may fall by around 27% to 36%. More aggressive actions and advanced technologies may accelerate the decrease in crude consumption by around 49%.

1.3 Background

The California Energy Commission (CEC) has identified that annual production of 125 million barrels of oil, or approximately 343,000 barrels of oil per day (bopd), is required to stabilize California's petroleum infrastructure, including its pipelines and refineries.[4] Furthermore, the CEC notes that this level of production is necessary to prevent price spikes at the pump. Southern California has ample supplies of recoverable crude oil that, if properly produced, could provide the needed in-state

[4] *JOINT OVERSIGHT HEARING - California's Transportation Fuels Transition* (2025, August 20). https://autl.assembly.ca.gov/system/files/2025-08/08.20.2025_joint-oil-oversight-hearing-background.pdf

production and more. However, Sacramento has, through policies and new laws, intentionally stopped nearly all new oil and gas development in California since 2022.[5] This has accelerated current and future production decline in the state, which now stands at over 6% per year as shown by the yellow curve in Figure 1. Less than 10 years ago, California was the third-largest oil producing state, producing well over 500,000 bopd, however, production stands at about half the amount.[6] Recent legislation, namely SB 237, which will enable Kern County to permit 2,000 wells annually in unincorporated parts of the county, is regarded as the solution to increasing California's oil production to a stable level.[7]

The dotted horizontal line in Figure 1 is the CEC's objective for stable production at 343,000 bopd. Anything under this level increases gasoline prices at the pump, severely increases the risk of gasoline shortages, and requires more imports of crude oil and gasoline, most likely from non-U.S. sources. California already imports the greatest amount of crude oil from sources such as Iraq, Ecuador and Brazil than any other state in the U.S. For example, in 2025, California is expected to import over 67% of its crude oil needs from non-U.S. suppliers, sending roughly $60 million a day of Californians' money overseas in payment. Adding insult to injury, California's increased reliance on non-U.S. suppliers further supports appalling social injustices and severe environmental destruction caused by largely unregulated crude oil extraction as is occurring today in Iraq and Ecuador.[8] [9] [10] These countries have historically been California's largest sources of imported crude oil.[11]

Of critical note, California is already well under the CEC's 343,000 bopd minimum level for stabilization, currently standing at approximately 285,000 bopd as of August 2025 according to data from the California Geologic Energy Management Division (CalGEM), which tracks all oil, gas, and geothermal drilling and production data in California. The "gap" between current level and the CEC's stabilization objective is further accentuated by the substantial in-state consumer demand for crude oil derived transportation fuels and products. There is no evidence that demand has dropped significantly since the pandemic, and only the one-time increase in remote work due to the pandemic in 2020/2021 (instantaneously reducing demand by 10%) has changed demand in the past decade. The most likely estimate is that demand will be substantial for the foreseeable future and that declines in consumption will be minimal in accordance with historical rates. The CEC posits that additional drilling in Kern County, spurred on by SB 237, will be sufficient to increase production; however, this is an unrealistic assumption, the reasons for which are detailed in the following sections.

---

[5] *Law limiting new oil wells in California set to take effect after industry withdraws referendum*. (2024, June 27). Cbsnews.com; CBS Sacramento. https://www.cbsnews.com/sacramento/news/law-limiting-new-oil-wells-in-california-set-to-take-effect/

[6] California Department of Conservation Geologic Energy Management. *WellSTAR Data Dashboard* https://app.powerbigov.us/view?r=eyJrIjoiNGQzZWU1N2QtNjNmYy00ODQyLWJlNDUtODBiYjg2MjYyYzIzIiwidCI6IjRjNTk4OGFlLTVhMDAtNDBlOC1iMDY1LWEwMTdmOWM5OTQ5NCJ9&pageName=ReportSectionf17b88a6302e7136a0b1

[7] *Bill Text - SB-237 Oil spill prevention: gasoline specifications: suspension: California Environmental Quality Act: exemptions: County of Kern: transportation fuels assessment: coastal resources*. (2025). Ca.gov. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202520260SB237

[8] Sandler Clarke, J. (2022, September 29). *Big Oil's dirty secret in Iraq*. Unearthed (Greenpeace U.K.). https://projects.unearthed.greenpeace.org/big-oil-iraq/

[9] Business & Human Rights Resource Centre. (2020, December 11). Ecuador: Indigenous Waorani file lawsuit against Chinese oil company PetroOriental, claiming gas flaring is contaminating their ancestral lands & threatening their survival. https://www.business-humanrights.org/en/latest-news/ecuador-indigenous-waorani-file-lawsuit-against-chinese-oil-company-petrooriental-claiming-flaring-is-contaminating-their-ancestral-lands-threatening-their-survival/

[10] Fernández Aguilar, C. (2023, September 12). *Hundreds of oil spill sites threaten Amazon Indigenous lands, protected areas*. Mongabay. https://news.mongabay.com/2023/09/hundreds-of-oil-spill-sites-threaten-amazon-indigenous-lands-protected-areas/

[11] California Energy Commission. (n.d.). *Foreign sources of crude oil imports to California* https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/foreign-sources-crude-oil-imports

2.0 California Oil Supply Forecasts with SB 237

2.1 CEC Forecast

The CEC has proposed that the additional crude oil production from Kern County alone, resulting from the codification of the Kern EIR and SB 237, will enable a ramp up in oil production to meet stabilization requirements within four years, as shown by their green curve in Figure 1. This would require a net <u>increase</u> in crude oil production of approximately 15,500 bopd annually from 2026 to 2030 to meet the CEC's estimate. However, California's statewide oil production is currently <u>declining</u> at a rate of about 18,000 bopd annually. As a result, approximately <u>33,500 bopd of new production, or 12,227,500 total barrels of new crude production</u> will need to be added annually to both overcome ongoing decline and achieve a net increase in oil production to reach the CEC's objective of 125 million barrels of in-state annual oil production by 2030.

We believe the CEC's reasoning and estimates are highly unrealistic. First, the new well production rates assumed by the CEC are not supported by data from CalGEM. The CEC stated that average new wells in Kern County will produce 30 bopd with a 7% annual decline rate.[12] However, and to the contrary, a recent analysis of CalGEM data has revealed that the average new well drilled in Kern County produces only about 13.5 bopd and has an average decline of 15.5% annually for the first five years of production.[13] Second, even when regulations were friendlier and inflation-adjusted oil prices were over $150 per barrel in 2013 and 2014, additional drilling in Kern County did not increase production to the levels forecasted by the CEC. Kern County only experienced an average net increase of about 10,000 bopd in both 2013 and 2014, a significant portion of which resulted from well stimulation treatments, which are now banned.[14] Third, around 70% of Kern County's production is of heavy oil, which requires steam flooding.[15] This process is more expensive today than in 2014 due in part to increased Cap-and-Trade fees and Low Carbon Fuel Standard costs.

2.2 Realistic Forecast

An average new well in Kern County costs around $500,000 and will return capital in around four to five years with current oil prices. While there are some projects with more attractive economics, the average new well in Kern County is only marginally economically viable today, as is the case with many oil producing basins in the United States.

---

[12] *JOINT OVERSIGHT HEARING - California's Transportation Fuels Transition* (2025, August 20). https://autl.assembly.ca.gov/system/files/2025-08/08.20.2025_joint-oil-oversight-hearing-background.pdf

[13] Ferrar, K. (2025, August 26). *California Oil Wells: Data Shows 13.5 Barrels/Day vs. 30 Claimed - FracTracker Alliance*. FracTracker Alliance. https://www.fractracker.org/2025/08/californias-new-oil-wells-average-13-5-barrels-day

[14] California Department of Conservation Geologic Energy Management. *WellSTAR Data Dashboard* https://app.powerbigov.us/view?r=eyJrIjoiNGQzZWU1N2QtNjNmYy00ODQyLWJlNDUtODBiYjg2MjYyYzIzIiwidCI6IjRjNTk4OGFlLTVhMDAtNDBlOC1iMDY1LWEwMTdmOWM5OTQ5NCJ9&pageName=ReportSectionf17b88a6302e7136a0b1

[15] *Gasoline Retail Prices by Brand Diesel Retail Prices by Region Counties With Thermal EOR Oil Fields Kern County Thermal EOR Oil Fields Kern County Thermal EOR Wells in 2020 Thermal EOR Wells Outside of Kern County in 2020 CHP Locations and Capacity CHP Facility Count, Capacity, Generation, and Grid Sales Featured Topic: California Oil Fields With Thermal Enhanced Oil Recovery PETROLEUM WATCH REFINERY NEWS INSIDE CALIFORNIA DIESEL RETAIL PRICES BY REGION CALIFORNIA GASOLINE RETAIL PRICES BY BRAND*. (2021). https://www.energy.ca.gov/sites/default/files/2021-12/2021-12_Petroleum_Watch_ADA.pdfm

The largest producer in the state, California Resources Corporation (CRC), produces roughly 47% of the oil in Kern County (about 100,000 bopd), while Chevron produces about 35%. The remaining 18% is from smaller independent producers.[16] We do not believe that these producers will come remotely close to drilling 2,000 wells every year, which would require spending approximately $1 billion in drilling capital annually. Specifically:

1. Drilling by the smaller producers will likely return to pre-pandemic drilling levels, with low oil price years. Consequently, we do not expect more than 250 new wells from this group. Conversations with smaller Kern County producers have indicated that oil prices consistently above $80 are needed to economically develop new heavy oil projects. At current Brent crude prices of $60 to $65 per barrel, crude oil prices will have to increase by 25% to 35% to make drilling economically attractive.

2. SB 1137 enables limitations and prohibitions on new drilling. For example, some of Chevron's production in the large Kern River oilfield is in a Health Protection Zone (HPZ) with CalGEM administration and subject to SB 1137 setback rules. Therefore, it is unlikely that new well drilling will be permitted withing the HPZ. An additional business decision is that the economics do not support a large drilling budget, and capital allocation. It is well-known that Chevron is moving its corporate functions from California in favor of Texas and is actively increasing its drilling in the Permian Basin to 1 million barrels a day, which have comparable costs to Kern County.[17] [18] Furthermore, a considerable portion of Chevron's California assets are in the Lost Hills oilfield, which requires now banned well stimulation treatments to recover light oil from the Diatomite formation. Therefore, based on our data and observations, we estimate that Chevron will drill no more than 150-200 new wells annually in California.

3. CRC expects to have free cash flow (after dividend payment) of approximately $360 million this year.[19] If 80% were allocated to new drilling, at most, around 580 new wells could be drilled. Given the weak economics of new drilling, we do not believe CRC will or could drill this many wells in 2026. Unless oil prices increase substantially, we do not believe they will do so in the future. Consequently, we are quite confident, barring any dramatic rise in oil prices or geopolitical events that disrupt production and supply chains, that the impact of SB 237, as shown by the red shaded zone in Figure 1, will be far less than that projected by the CEC.

---

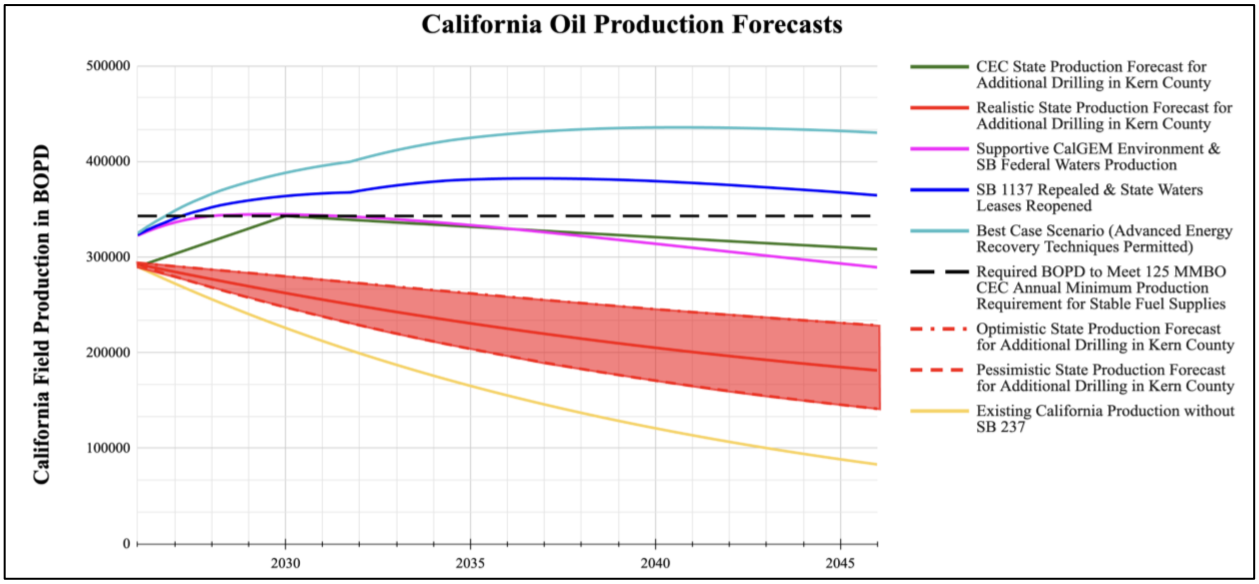
[16] California Department of Conservation Geologic Energy Management. *WellSTAR Data Dashboard* https://app.powerbigov.us/view?r=eyJrIjoiNGQzZWU1N2QtNjNmYy00ODQyLWJlNDUtODBiYjg2MjYyYzIzIiwidCI6IjRjNTk4OGFlLTVhMDAtNDBlOC1iMDY1LWEwMTdmOWM5OTQ5NCJ9&pageName=ReportSectionf17b88a6302e7136a0b1

[17] Chevron Policy, Government and Public Affairs. (2024, September 20). *Chevron announces headquarters relocation and senior leadership changes*. chevron.com. https://www.chevron.com/newsroom/2024/q3/chevron-announces-headquarters-relocation-and-senior-leadership-changes#:~:text=The%20company's%20headquarters%20will%20move,1%2C800%20retail%20stations%20in%20California.

[18] De Lombaerde, G. (n.d.). *Chevron's Permian production tops 1 MMboe/d, executives shift focus to cash flow*. https://www.ogj.com/general-interest/companies/article/55307192/as-chevrons-permian-production-tops-1-million-boe-d-executives-shift-focus-to-cash-flow

[19] https://www.crc.com/static-files/e50659b6-eee5-460f-858d-05b215ccede1

Figure 1



(Source: Data from CEC and CalGEM. Calculations by authors.)

Specifically, as indicated in Figure 1, we have generated various production scenarios, with concentrations on three potential outcomes shown within the red shaded area:

- Optimistic: 1,000 wells per year having an average initial production in years 1-5 of 15 bopd with an average 15.5% annual decline on top of California's current terminal 6.2% decline for existing production.

- Most likely: 750 wells per year having an average initial production in years 1-5 of 13.5 bopd with an average 15.5% annual decline on top of California's current terminal 6.2% decline for existing production.

- Pessimistic: 500 wells per year having an average initial production in years 1-5 of 12 bopd with an average 15.5% annual decline on top of California's current terminal 6.2% decline for existing production.

Clearly, SB 237, which effectively makes much of rural Kern County an oil and gas regulatory island within the state, provides additional sorely-needed oil production and is a step in the right direction. However, as structured, SB 237 does not remotely come close to meeting the state's stabilization requirements, leaving California still severely short on in-state production as shown in Figure 2.

Figure 2

Estimated In-State Oil Production Shortages

Year	2026	2030	2035	2040	2045
Production Shortage in bopd	52,100	70,800	92,700	111,700	127,500
Annual Production Shortage (bbls)	19,017,000	25,842,000	33,836,000	40,771,000	46,538,000

(Source: Data from CalGEM. Calculations by authors.)

2.3 Other Scenarios

The magenta curve in Figure 1 shows projected production assuming our most likely estimates for new production in Kern County resulting from SB 237 in addition to the following:

1. Restarting the oil platforms in federal waters off Santa Barbara (namely the Santa Ynez Unit) in a proper manner that is consistent with California's environmental policies and regulations, beginning in 2026.

2. That CalGEM and the State Water Board immediately return to using historical, well-accepted criteria for actions such as creating aquifer exemptions for zones with non-potable and/or naturally contaminated water, setting historically consistent and safe water injection rates, and permitting workovers on existing wells throughout the state (these state agencies have recently adopted rules that are often arbitrary and unscientific). This would enable additional production from existing infrastructure and equipment that is otherwise held back by various recent regulations.

The dark blue curve represents the magenta curve as well as additional action of repealing SB 1137 and responsibly restarting production in the South Ellwood Field (offshore from UC Santa Barbara), which would allow development of high rate, low per barrel cost wells in the Santa Barbara Channel within the next five years. It would also enable considerable production via wells drilled from existing drilling islands in the LA Basin even sooner. Unlike Kern County, where breakeven costs of new wells are above $45 per barrel, these areas have breakeven costs of under $20. Even in a low crude oil price environment, these wells are highly productive and very economical. Thirty new wells drilled in the Santa Barbara Channel would do more than all the Kern County drilling toward stabilizing production.

While this scenario may seem politically formidable, we believe that some new wells may not require the repeal of SB 1137, since they benefit the environment and human health by reducing toxic local seep emissions, which are particularly severe in the Santa Barbara Channel and in parts of Los Angeles.[20] [21] This is an important nuance and one which must be communicated to all stakeholders, where, hopefully, climate, environmental, and social justice will prevail.

Production from the South Ellwood Field, in particular, would be uniquely beneficial to the state because it is located in state waters. Thus, in addition to normal tax revenues, the state enjoys a 16.67% royalty on every barrel produced, which collectively would amount to around $6 billion over 20 years.

Finally, the light blue curve represents a best-case scenario where provisions from the dark blue curve are kept and well stimulation treatments and enhanced oil recovery with carbon dioxide are allowed to proceed in a commonsense manner that still protects the environment. Before they were banned,

---

[20] USGS. *California State Waters Map Series—Offshore of Coal Oil Point, California* (2014, August 7). https://pubs.usgs.gov/sim/3302/

[21] Etiope, G., Doezema, L. A., & Pacheco, C. (2017). *Emission of Methane and Heavier Alkanes from the La Brea Tar Pits Seepage Area, Los Angeles* https://agupubs.onlinelibrary.wiley.com/doi/full/10.1002/2017JD027675

well stimulation treatments accounted for approximately 35% of new production in Kern County annually. While Kern county's production today is predominantly of heavy crude oil, well stimulation treatments and enhanced oil recovery using carbon dioxide could enable substantial production of light crude oil while also storing and sequestering carbon emissions. Several oilfields in Kern county such as North Belridge, South Belridge, Lost Hills, Elk Hills, and Buena Vista contain substantial of light oil resources—the first four of which hold approximately 2.8 billion barrels of oil that is recoverable with these technologies within their Diatomite and deep Stevens/Monterey reservoirs.[22] However, these considerable oil resources are not producible today, even under SB 237, because these advanced energy recovery techniques, which required to recover this oil, are still prohibited.

While well stimulation itself is not responsible for severe environmental impacts, the careless disposal of wastewater has been responsible for issues like groundwater contamination and induced seismicity across the United States, especially in regions of Oklahoma and Texas.[23] In California, however, a state-commissioned study by the California Council on Science & Technology (CCST) concluded that well stimulation practices in California oil fields differ significantly from those in the rest of the country and generally pose minimal-to-no risk.[24] For instance, far less water is used due to the smaller subsurface footprint of stimulated wells. No groundwater contamination due to well stimulation in California was found and the potential for future groundwater contamination is also nearly absent as the majority of wells that have been stimulated in California are located within existing oilfields in remote regions in the westside of the San Joaquin Valley where no freshwater aquifers exist.[25] The CCST study also found that oil produced from stimulated wells in California has the added benefit of having a low carbon-intensity score. Still, if well stimulation operations were allowed to resume in California, proper and commonsense oversight should be put into place to ensure people and the environment are protected.

There is a general belief that oil production is polluting. While that may have been true even two decades ago, it is not an accurate representation of modern crude production today–at least not in the LA Basin and in Santa Barbara and Ventura Counties. Successful emissions reductions programs administered by the state have helped to considerably mitigate and eliminate emissions from oilfield equipment, and there have been no major spills for over 10 years. While spills are harmful for the environment and should be avoided, <u>the spills that have happened are small compared to natural seeps in the area, which create the equivalent of a major man-made spill every week</u>. These natural seeps are responsible for the lion's share of the air and ocean pollution in the Santa Barbara area, and likely impact human health near oil fields in the LA Basin, as well. These seeps have been documented to emit *10-100 times* more methane and VOCs into the atmosphere in the LA Basin than crude oil production operations. In the Santa Barbara Channel, natural seeps are estimated to leak between 300-

---

[22] USGS (2012, April 12). *Assessment of Remaining Recoverable Oil in Selected Major Oil Fields of the San Joaquin Basin, California.* https://pubs.usgs.gov/fs/2012/3050/fs2012-3050.pdf

[23] Skoumal, R. J., & Trugman, D. T. (2021). *The proliferation of induced seismicity in the Permian Basin, Texas.* Journal of Geophysical Research: Solid Earth, 126, e2021JB021921. https://doi.org/10.1029/2021JB021921

[24] California Council on Science & Technology. (2015). *Summary of SB 4: Well stimulation technologies — hydraulic fracturing and other well stimulation.* https://ccst.us/wp-content/uploads/2015SB4summary.pdf

[25] Metzger, L. F., & Landon, M. K. (2018). *Preliminary groundwater salinity mapping near selected oil fields using historical water-sample data, central and southern California* (U.S. Geological Survey Scientific Investigations Report 2018-5082). https://doi.org/10.3133/sir20185082

400 barrels daily, with about half that amount coming from the Coal Oil Point seep field near UC Santa Barbara.[26] The seeps are sourced directly by underlying oil and gas fields. It has been conclusively shown that, over the long term, producing this oil and gas reduces and often eliminates natural seepage in seep-prone California oilfields.[27] By considering the role of natural seeps in local emissions, policymakers in Sacramento and environmental organizations could play a key role in supporting responsible oil production practices that help reduce methane, oil, and VOC releases in these regions.

2.4 Oil and Gasoline Consumption

Gasoline prices are largely formed by the price of crude oil, the supply of crude oil, and the demand for gasoline, or consumption. In California, state mandated taxes and costs for programs such as Cap & Trade, which support the California Highspeed Rail Project, alongside additional taxes and regulatory costs, represent 27% to 30% of the current retail price of $4.66 per gallon.

Despite various claims of significantly reduced consumption, there is no indication that California gasoline consumption has or will decline at any material rate for the foreseeable future. In fact, the data is to the contrary. Consumption based on California Department of Tax and Fee Administration (CDFTA) data for the 2001 to 2024 period indicates that gasoline consumption declined 11.01%, or less than one percent annually. The 10-year average annual gasoline consumption, based on calendar year and CDFTA data, is 14.406 billion barrels of gasoline per day.[28] On average, California consumes between 36 and 40 million gallons of gasoline per day, or 13.1 to 14.6 billion gallons of gasoline annually.[29] CDFTA data for 2024 indicates that California consumed approximately 36.2 million gallons of gasoline per day. The CEC reported that California also consumed around 11.51 million gallons per day, or about 4.2 billion gallons annually of aviation jet fuel in 2024.[30] The CEC also predicts that jet fuel consumption will increase relatively linearly by 20% through 2040, and likely by over 25% through 2045. This would mean California could be consuming approximately 14.38 million gallons per day of jet fuel, or around 5.25 billion gallons per year by 2045. In terms of barrels, this would amount to approximately 125 million barrels of jet fuel consumed annually in California.

Our forecasts do not agree with either the CEC or California Air Resources Board (CARB) estimates as to overall decreases in consumption and the rates of decline of transportation fuel and crude oil consumption as the data simply does not support it. Additionally, due to the Federal recissions for the subsidies for the purchase of EVs, adoption rates for those vehicles are expected to continue to slow.

---

[26] Lorenson, T. D., Leifer, I., Wong, F. L., Rosenbauer, R. J., & others. (2011). *Biomarker chemistry and flux quantification methods for natural petroleum seeps and produced oils, offshore southern California* (USGS Scientific Investigations Report 2011–5210). U.S. Geological Survey. https://pubs.usgs.gov/sir/2011/5210/sir2011-5210_text.pdf

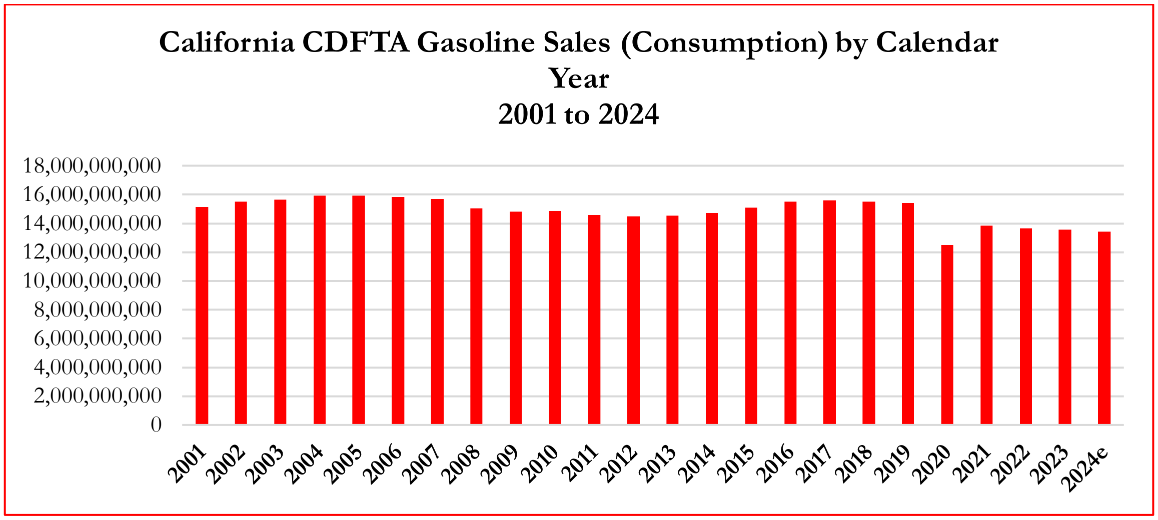
[27] Boles, J. R., Garven, G., & Peltonen, C. (2023). *Hydrocarbon production reduces natural methane seeps in the Santa Barbara Channel*. Marine and Petroleum Geology, 151, Article 106187. https://doi.org/10.1016/j.marpetgeo.2023.106187

[28] *Fuel Taxes Division Statistics & Reports – 2010*. (2025). Ca.gov. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts10.htm

[29] Various including CEC and EIA and authors.

[30] California Energy Commission. (2024, November 7). *Transportation Energy Demand Forecast: Major Updates and Results* (Prepared by A. Freeman, N. Saxena, & F. Kabir; TN No. 259930). 2024 Integrated Energy Policy Report Update, Docket No. 24-IEPR-03. https://efiling.energy.ca.gov/getdocument.aspx?tn=259930

Figure 3



(Source: CDFTA)

The largest drop in California gasoline consumption since the 1980s came during the pandemic years of 2020 to 2021, when demand fell 19%. Since the pandemic trough of 2020, California's GDP increased by 13%, while gasoline consumption has rebounded by 6.8%.[31] For 2024, CDFTA consumption data indicates a slight decline of 0.945% from 37,163,227 gallons per day in 2023 to 36,812,038 per day. For 2025, gasoline consumption is expected to remain about the same as 2024, perhaps slightly less but not materially lower, especially with the plateauing of EV sales in California and the revocation of federal subsidies and tax credits.[32] Notably, in California, consumer demand for aviation fuel increased 113% from 2001 to 2022. For the 2015 to 2024 period, CDFTA data indicates that jet fuel consumption in California, which is the fastest growing fuel product category in the state, increased by 31%.[33] Based on current assumptions, California will require approximately 578,000,000 to 581,000,000 barrels of petroleum annually to support its current economic activity, as well as its exports to Arizona and Nevada. In terms of gasoline consumption, California, alongside the fuel it supplies to Nevada and Arizona, is estimated to require between 14.2 to 15.5 billion gallons of gasoline per year, or about 38,900,000 to 42,470,000 gallons per day.

This estimate is based on historical consumption behavior as adjusted for natural and incentivized declines for gasoline consumption, as well as consumer preferences. If economic activity slows or there is a significant disruption to crude and gasoline supply chains, consumption generally declines. In contrast, increases in aggregate economic activity are usually accompanied by increases in crude oil and gasoline consumption. If consumption remains relative stable or declines only slightly while supplies drop, prices will increase. California is confronting a severe decline of its in-state production and will, most likely, be increasingly dependent on foreign suppliers of gasoline and complex supply

---

31 *Fuel Taxes Statistics & Reports*. (2020). Ca.gov. https://cdtfa.ca.gov/taxes-and-fees/spftrpts.htm

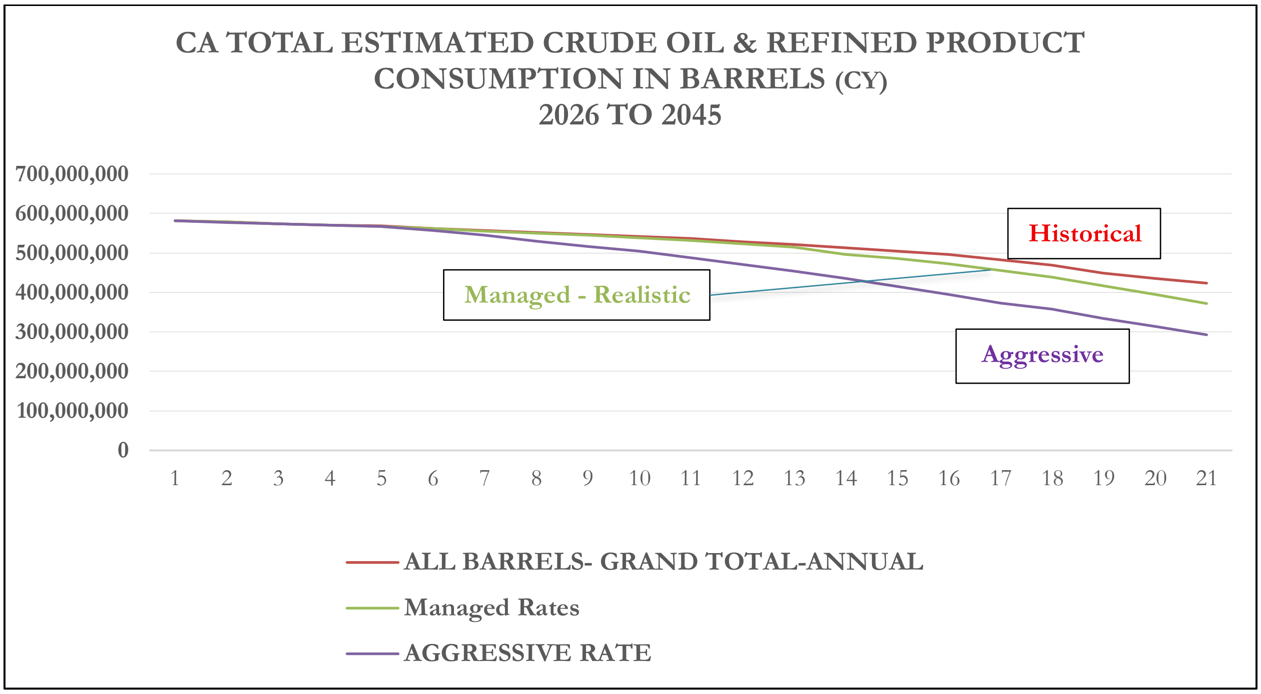
32 CARB's estimate of 35% adoption rates for EVs in 2026 exceed actual DMV data which shows a 9.6% decline to 22.6% in EV registrations for the first half of 2025. Furthermore, adoption rates appear to have plateaued, for the time being, at 25.03% in 2023, and 25.01% in 2024. Federal subsidies and tax credits were also rescinded on October 1, 2025.

33 *Fuel Taxes Statistics & Reports*. (2020). Ca.gov. https://cdtfa.ca.gov/taxes-and-fees/spftrpts.htm

chains, leading to supply instability and increased consumer prices for gasoline. The CEC has estimated that 125,000,000 barrels of crude oil in-state production is required to "stabilize" California's energy needs and infrastructure. Accordingly, California will need to import upwards of 453,000,000 barrels of crude oil and refined products annually, predominantly from non-U.S. suppliers. This equates to roughly 4% more crude than 2024 levels from petrostates such as Iraq, Ecuador, and Brazil to equalize supply and demand, assuming, of course, that SB 237 results in an expeditious increase of in-state oil production…but that is, as demonstrated in this study, an ambitious assumption. Furthermore, the CEC estimate of 343,000 bopd as to the amount of in-state crude production necessary to stabilize California's fuel supplies still maintains California's long-term dependency on generally unregulated and highly pollutive non-U.S. crude oil and foreign-sourced gasoline.

Illustrated in the following chart are three scenarios, each depicting estimated changes in California petroleum consumption.

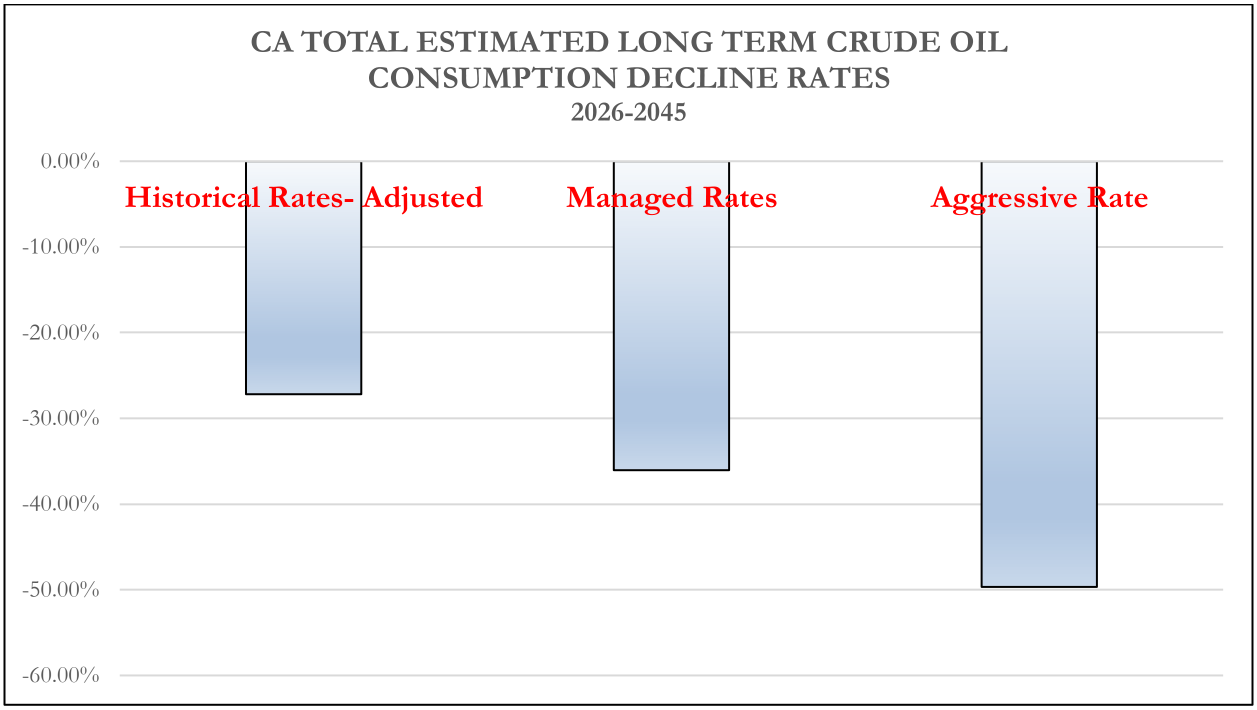
Figure 4



(Source: Data from CEC and CDFTA. Calculations by authors.)

At this time, there are no indications that consumption will decline faster or further, ceteris paribus, than historical averages. As provided in Figure 4 and based on assumptions and estimates as to aggregate economic activity, the most realistic decline in consumption of crude derived fuels and products is associated with historical behaviors, which indicate a 27.18% decline in consumption from 2026 to 2045. A more managed, moderately aggressive approach indicates a 36.05% decline in consumption. The most aggressive approach yields a 49.67% decline, but is currently impractical and not economically feasible. In all scenarios, SB 237 fails to adequately address California's petroleum needs without substantial and likely infeasible increases in imports of non-U.S. crude oil and gasoline.

Figure 5



(Source: Data from CEC and CDFTA. Calculations by authors.)

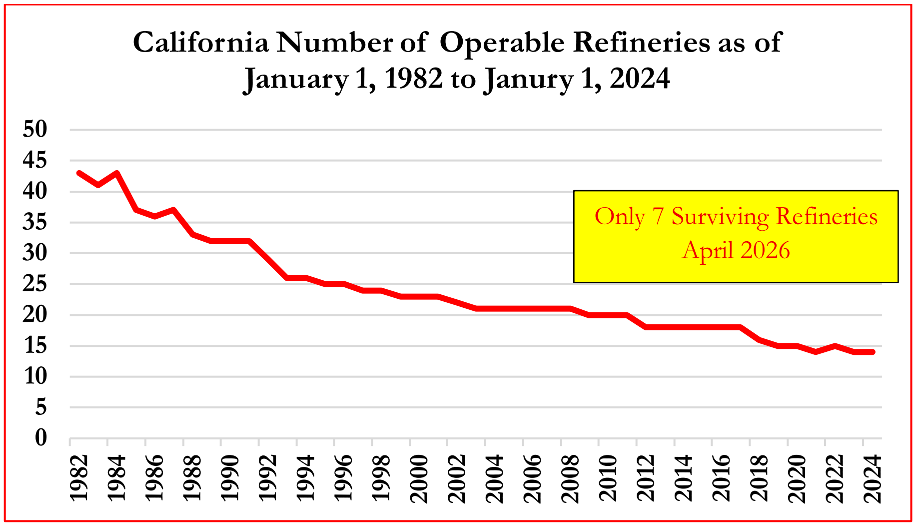
Complicating California's oil production dilemma is the long-term decline and degradation of in-state refineries. As indicated below, the number of refineries in the state has fallen by over 60%. Currently, California is down to just 8 capable of producing gasoline for the state. By April 30, 2026, California will be down to 7 operating refineries capable of producing California compliant fuels.

As indicated in a previous study, California is set to lose between 6.2 to 9.7 million gallons of in-state gasoline production per day.[34] This loss, without a corresponding decrease in demand, will most likely be made up by imports of foreign sourced gasoline. The importation of such quantities of gasoline will create logistical issues which are exponentially more complex than in-state production and pipeline usage. For example, both port and road congestion are expected to increase, the number of maritime shipments is expected to increase significantly, thus increasing spill risk, greenhouse emissions and air pollution. Furthermore, fuel barges will be needed to transport both crude and gasoline to refineries and converted gasoline storage facilities that do not have maritime access. This will also lead to presently air pollution-burden port communities in California experiencing up to a fivefold increase in the number and frequency of pollutive maritime vessels to facilitate this risky and piecemeal solution to adequately supply California with fuel per CARB's own analysis.[35] In all instances, the cost of fuel will increase, and any disruption in the supply chains will adversely impact prices and fuel availability.

[34] Mische, Michael A. *ENSURING CALIFORNIA-(5-5-25)*. (2025, May). Google Docs. https://drive.google.com/file/d/1CVsBHQ0s4FX57xQD2iy0ZD1V_MlKJMZX/view

[35] California Air Resources Board. (2022, December). *2022 Scoping Plan for Achieving Carbon Neutrality*. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

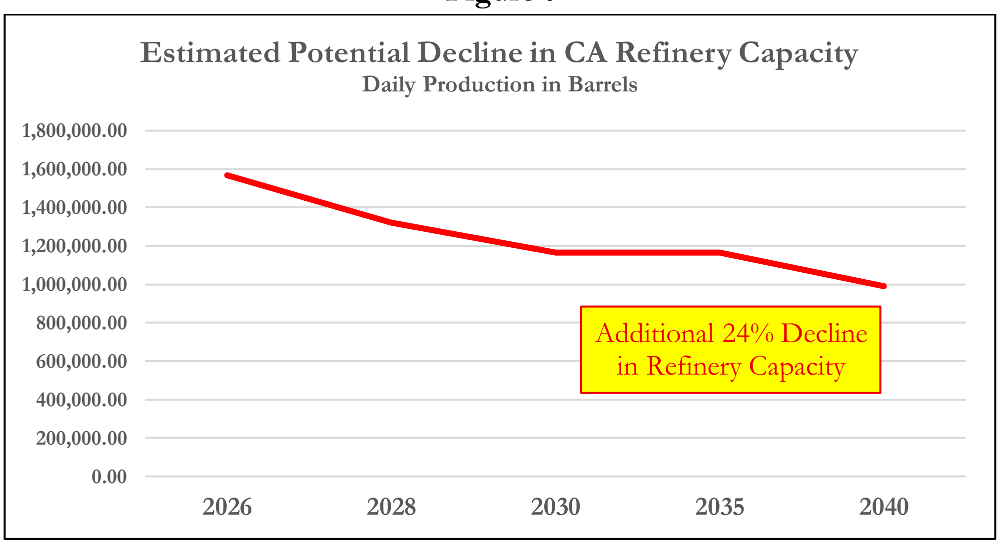
Figure 6



(Source- https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=8_NA_8O0_SCA_C&f=A)

Since 2023, California refinery processing capacity has dropped by a collective 21%.[36] Projecting forward, given the current regulatory environment and high operating costs, California could experience additional refinery closures. This would exacerbate fuel supplies and drive prices higher. Below is a chart depicting the potential loss in California refinery processing capacity over the forthcoming years. The estimated losses would be accelerated by the closure of the major northbound pipeline system and, despite SB 237, reduced in-state production of crude oil.

Figure 7



(Source: Data from CEC. Calculations by authors.)

[36] CY 2023 to April 2026.

2.5 Impact on Retail Gasoline Prices

Multiple factors inform gasoline prices. Based on our analysis of varying supply levels, most probable fuels consumption, and the impact of losing two or more refineries, California retail gasoline prices will increase, irrespective of SB 237. The increase is attributed to reduced refining capacity, increased cost associated with the importing of gasoline, increased transportation costs, declining in-state production, and relatively constant demand. The worst scenario for consumer gasoline prices would be the continued loss of in-state refinery capacity and the loss of the primary northbound pipeline system due to a lack of sufficient in-state crude oil production. The combination of these two events would potentially be catastrophic to the California economy. Furthermore, the loss of pipeline infrastructure could result in an armada of crude oil tanker trucks transiting on Interstate Highway 5 as some of the crude oil from the San Joaquin valley would have to be shipped via tanker truck once the pipeline is shut down. Collectively, these factors and events could potentially drive consumer prices, at relatively constant demand, towards $12 a gallon or more. The chart below summarizes the possible prices that California could be confronting based on the various scenarios of SB 237, as well as assumptions for Brent crude oil prices, wholesale prices, pipeline availability, refinery capacities, foreign sources of gasoline, transportation costs, and increasing regulatory costs associated with Cap & Trade, state excise tax, plus other state and local regulatory costs.

Figure 8

CALIFORNIA GASOLINE PRICE RANGE ESTIMATES UNDER SB 237				
Possible Retail Price Implications Under Various Production, Supply & Pipeline Utilization Rates				
Current (Base)	Optimistic	Most Likely	Pessimistic	Worst
4.62 - 5.77	5.91-7.66	6.26-7.78	8.46 - 10.00+	10.00 - 12.18

(Source: Calculations by authors.)

3.0 Summary

SB 237 is a step in the right direction, but it will not, by itself, stabilize in-state oil production. Depending on the price of crude oil and supply stability, gasoline prices are expected to increase by $0.50 to more than $1.00 per gallon in the next year. If in-state crude oil output, pipeline infrastructure, and refinery production are not stabilized, California will be become increasingly susceptible to extreme price shocks during times of geopolitical unrest and supply chain disruptions. Additional refinery closures would likely also result.

To stabilize production and provide the necessary stabilization to ensure California's energy security, California needs to suspend and reverse the recent procedural changes within CalGEM and the State Water Board designed to stop oil production. California also must encourage and incentivize oil and gas production in other areas of the state besides Kern County, particularly in the Santa Barbara Channel and in the LA Basin. In these areas, new oil supplies can come online quickly, while also reducing local pollution and greenhouse gas emissions, thereby contributing to climate and environmental justice. Moreover, the profitability of these activities is typically considerably higher than in Kern County, resulting in far greater revenue to the state.

<u>The additional production enabled by SB 237 will be insufficient to have any material influence on long term prices and will fail to provide an adequate supply of in-state crude oil</u>; but, the passage of SB 237 is an important first step and a public acknowledgement by Governor Newsom and the State Legislature that increasing in-state crude oil production is essential to the California's economic vitality and stability. At best, SB 237 will help to slightly curb inevitable increases in consumer prices, but alone, will neither reduce nor reverse them. Furthermore, the regulatory components of consumer gasoline prices such as Cap & Trade, Low Carbon Fuel Standard, the state excise tax, and local state taxes are expected to <u>increase annually</u>, thus contributing to higher consumer gasoline prices.

As we have demonstrated by our analysis, SB 237 alone will not ensure adequate supplies and stability. Our analysis indicates that what is required to sustain California's surviving refineries and pipeline infrastructure is a <u>comprehensive plan</u> to create a more hospitable operating environment and statutory assurances allowing additional crude oil production from both onshore and offshore California producers, as well as extended use of existing and rehabilitated pipelines. California's energy stability objectives would be well served by revisiting the extent and limitations imposed by recent legislation such as SB 1137, AB 1167, AB 3233, and the various powers of regulatory agencies such as the California Coastal Commission, State Water Board, and CARB.

California now has the opportunity to demonstrate that environmental responsibility and energy security are not mutually exclusive. Facilitating efficient permitting and responsible production alongside well-informed, commonsense regulations will ensure California's ecosystems and communities are safeguarded while oil production is concurrently increased in a conscientious and environmentally sound manner. Policies which reduce and restrict in-state production are counterproductive as they do not reduce California's demand for crude oil. Instead, they lead to the outsourcing of California's oil supply to oil producing regions with minimal labor and environmental regulations. This, in turn, ultimately increases emissions and pollution levels worldwide while also reinforcing California's support for human rights injustices and environmental destruction abroad by purchasing and using foreign sources of crude oil. Considering this reality, California can lessen its overall climate and environmental impact by producing oil in California responsibly, using additional in-state production to replace pollutive, foreign-sourced oil imports. This will ensure that, as the state moves toward alternative energy sources, the crude oil consumed within California is sourced under strict environmental oversight and benefits the state socially and economically.

It is also essential to recognize that, while there have historically been cases of negligent producers in California, today, the state hosts producers who comply with strict environmental and safety regulations, distinguishing the state from other regions such as Texas where regulations are often lacking and environmental issues persist. These modern California producers demonstrate that environmental and climate goals can coexist with oil and gas production. California can set an example for environmental leadership by establishing a straightforward regulatory framework that incentivizes responsible producers and upholds accountability while still appropriately punishing irresponsible and reckless producers. The state can set an example both at home and abroad by demonstrating that energy security, economic stability, environmental preservation, and social wellbeing can all be maintained. In doing so, California can create a future for itself where communities are protected, emissions are mitigated, pollution is reduced, and the energy transition is managed equitably and responsibly. This would demonstrate to the rest of the world that environmental leadership, economic health, and responsible oil production can occur simultaneously, beginning right here in California.

For the Golden State, there is extreme urgency. Failure to act and reform policies now will only lead to higher fuel prices, more pollution, additional emissions, further support for injustices abroad, and contribute to additional instability in California's energy markets as more producers and refiners voluntarily exit the state for more attractive and economically superior environments. Ultimately, a lack of action will also cause additional socioeconomic and environmental inequities in California wherein the least fortunate and most vulnerable individuals, families, and communities will disproportionately fall victim to higher prices, pollution, and a lack of affordable and reliable energy, further driving socioeconomic disparities and reinforcing cycles of poverty as they are the least able to absorb higher costs. Without meaningful and practical policy changes that prioritize both energy security and real environmental progress, California risks sacrificing its own prosperity, climate goals, and environmental leadership, while failing to achieve the social equity and sustainability milestones its people deserve, undermining California's broader goals of environmental justice and economic opportunity for all its residents.

Attachment F:
M. Mische, J. Rector, J. Silvi, "California's Oil and Gasoline Conundrum: A Blueprint to Address California's Gasoline Insecurity, High Prices and Avert More Pipeline & Refinery Closures" (Dec. 1, 2025).

CALIFORNIA'S OIL AND GASOLINE CONUNDRUM:

A BLUEPRINT TO ADDRESS CALIFORNIA'S GASOLINE INSECURITY, HIGH PRICES AND AVERT MORE PIPELINE & REFINERY CLOSURES

December 1, 2025
Embargoed until 0600 Pacific Time
For Release to Media

Michael A. Mische
University of Southern California

James W. Rector
University of California, Berkeley

Joseph B. Silvi
University of California, Berkeley

Disclaimer & Statement of Independence

This paper represents the independent work, analysis, perspectives, representations, and opinions of the authors. It does not, in any manner, explicitly or implicitly, reflect, represent, or describe the views, opinions, policies, and/or positions of the University of California, or the University of Southern California, and their respective faculty, employees, administration, or students.

In creating and presenting this work, the authors have made all reasonable attempts to ensure the accuracy and consistency of the data, attribution to data sources, analysis, and calculations. Nonetheless, variances in data and presentation may exist to some degree. In the authors' opinion, such variances will not materially change the tenor, trajectories, impressions, interpretations, conclusions, or possible implications associated with the data, data sources, and related analysis herein.

The work presented herein is provided for informational, research, discussion, policy, and educational purposes. In performing this work, the authors have not received any special compensation and have no promise or anticipation of any compensation for the work presented herein. This work and the authors are entirely independent and not affiliated with, in any form, and are not advocating on behalf of or representing any petroleum company, organization, or foreign entity. No funding from any external sources, entities, agents, or associations was received, advanced, promised or granted for the work presented herein. No funding for this study was provided by the University of Southern California or the University of California, Berkeley. This study is entirely self-financed by the authors.

Data Sources and Methods

For this research effort, a series of critical questions were developed, and data related to addressing those critical questions were identified, obtained, organized, and analyzed. The research involved in this work is widely available and includes but is not limited to verifiable sources such the California Energy Commission, U.S. Energy Information Agency, Bloomberg, U.S. Department of Energy, SEC filings, International Energy Agency, Oil & Gas Journal, American Petroleum Institute, the California Department of Tax and Fee Administration, the U.S. EPA, California Air Resources Board, Statista, California Attorney General's Office, California Legislative Analyst's Office, U.S. Department of Interior, Bureau of Labor Statistics, California DMV, California Geologic Energy Management Division, and the U.S. Oil and Gas Association. Readers are strongly encouraged to avail themselves to the many sources and authorities footnoted herein.

For additional information or inquiries, please contact:

Professor Michael A. Mische, USC-Marshall
Email: mische@marshall.usc.edu

Professor James W. Rector, UC-Berkeley
Email: jwrector@berkeley.edu

Executive Summary

California faces immediate risks to gasoline supply due to declining in-state production, refinery closures, and an imminent northbound pipeline collapse. In this study, we demonstrate how increasing crude oil production in certain regions in California will preserve and sustain both refineries and pipelines and avert severe price shocks in the consumer fuel market. With the AAA price of gasoline in California 51% higher than the national average, Californians are already paying the highest price in the U.S. [1] The impending loss of two refineries and the collapse of the only remaining northern pipeline, together with increasing dependency on non-U.S. gasoline sources to California could drive the price of gasoline to double that of the national average by calendar year end 2026.

After years of tearing down California's in-state oil and gasoline production, Governor Newsom and the California legislature have done a stunningly abrupt about-face in 2025 and conceded that California's oil production and gasoline refinery infrastructures are still essential to its economy and that new production is needed. SB 237, which allows for up to 2,000 new drilling permits a year in Kern County, and AB 30 that allows for the sale of E15 gasoline, form the centerpieces of Governor Newsom's and the Legislature's plan to alleviate gasoline supply insecurity, moderate consumer prices and stabilize the markets. Unfortunately, SB 237 is too little and too late, and AB 30 is overly optimistic. <u>New Kern production stimulated by SB 237 will not be enough</u> to stem the natural decline of Kern County oil production in the current low crude price and regulatory environment. Furthermore, <u>it is highly unlikely that AB 30 will universally reduce gasoline prices by $0.20 a gallon</u> across the state as proclaimed by the Governor. Inevitably, in state crude oil production will continue to decline unabated and lead to further pipeline and refinery shutdowns over the next few years, increasing supply instability and prices.

Years of over regulation and industry demonization have now left California with limited choices and a critical call to action. Our analysis indicates that <u>California can navigate its way out of this government-created crisis</u> and avoid supply vulnerabilities and escalating consumer prices by implementing the following action steps:

1. California's most immediate, viable and sustainable option is to increase in-state crude oil production. <u>The best, and essentially only way to achieve and sustain this benefit is to reopen the Las Flores Canyon pipeline system</u> on the Central Coast and safely increase offshore crude oil production in the Santa Ynez Unit (SYU).

2. Restoring production in this region would immediately provide <u>45,000 barrels per day</u> of clean, low-decline California crude suited for SoCal refinery configurations. Up to <u>100,000 barrels per day</u> could be produced from the Santa Barbara channel. This oil can be directed south to the Los Angeles area refineries thereby freeing up tens of thousands of barrels of Kern County oil compatible with Northern California refineries to be redirected north to the surviving PBF-Martinez refinery Additionally, <u>350,000 barrels of SYU crude oil is currently in onshore storage tanks</u> which could be delivered into the California system within a few days' notice upon reopening the Las Flores Canyon pipeline system.

Failure to act and failure to increase in-state crude oil production will only accelerate the exit of California refineries from the state, increase global GHG emissions, further California's contributions to environmental destruction, force greater reliance on foreign suppliers, increase consumer prices, and diminish U.S. national security.

[1] As of 11/28/25. https://gasprices.aaa.com/?state=CA

CALIFORNIA'S OIL AND GASOLINE CONUNDRUM:

A BLUEPRINT TO ADDRESS CALIFORNIA'S GASOLINE INSECURITY, HIGH PRICES AND AVERT MORE PIPELINE & REFINERY CLOSURES

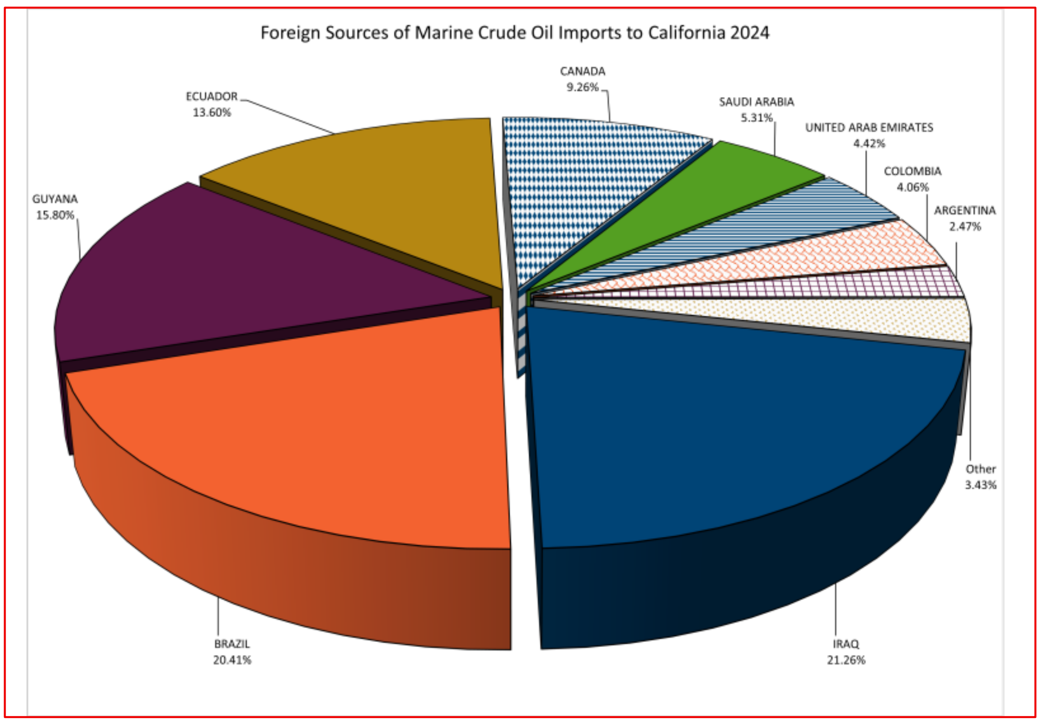
Table of Contents

1.0 California's Oil Conundrum and Reliance on Foreign Suppliers

It is well-documented that California is an oil supply island. There are no in-bound crude oil or gasoline pipelines from anywhere in North America into California and there never have been any. Since the 1860s and throughout the twentieth century, California produced and refined enough in-state oil to provide the lion's share of the gasoline it needed. At one time, California was the world's largest exporter of oil. Crude oil production in California provided fuel to U.S. military forces during World War-II, the Korean War, Vietnam War, and supported the state's rapid population and economic expansion that began in the 1950's and continues today. Fossil fuels provide around 38% of California's electrical generation.[2] Today, the oil and gas industry in California accounts for 8% of the state's GDP, and significantly, it is the first 8%. Without oil and gas, the remaining 92% would be unattainable.

Just 25 years ago, California produced roughly half of the oil it consumed. Today, California only produces around 20% of its needed crude oil and imports over 65% of its oil needs from non-U.S. sources, via highly pollutive maritime tankers which are predominantly owned and operated by foreign-flagged carries. For 2024, the majority of California's foreign oil came from Iraq (21%), Brazil (20%), Guyana (16%), and Ecuador (14%).[3]

Exhibit 1.0



(Source: CEC)

In addition to crude oil, California has become increasingly reliant on non-U.S. imports of refined products to meet its demand for gasoline, diesel, and jet fuel. In fact, despite having the 5th largest oil reserves in the nation, of all 50 states, California is the most heavily dependent on non-U.S. produced

[2] California Energy Commission. (2025). *2024 total system electric generation.* https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2024-total-system-electric-generation

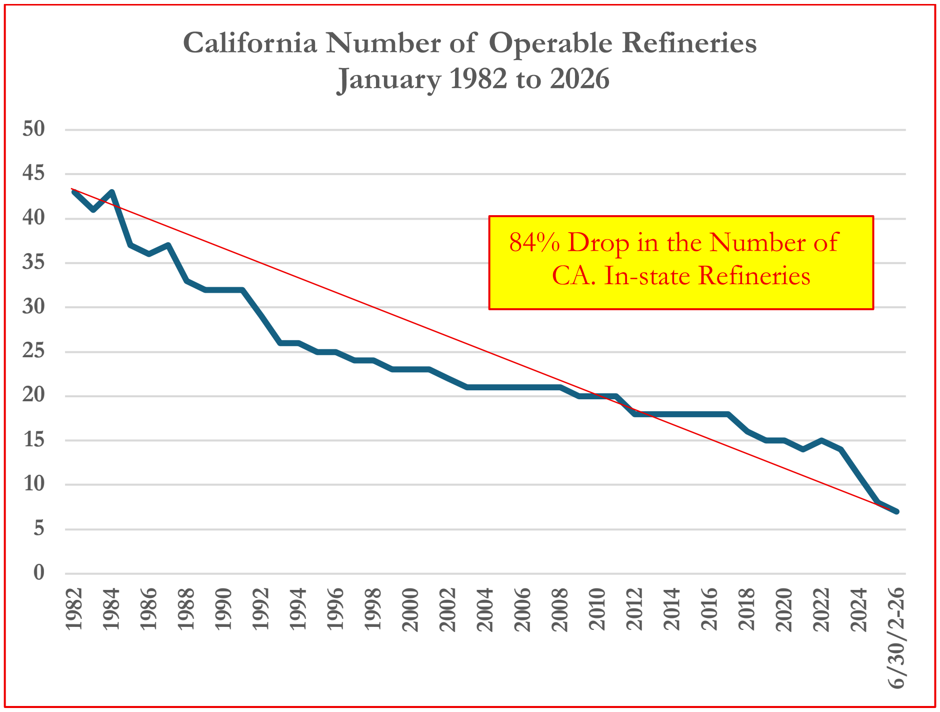
[3] California Energy Commission. (2025). *Foreign sources of crude oil imports to California.* https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/foreign-sources-crude-oil-imports

oil imports. These imports are necessary because there is not enough in-state crude oil production and refinery capacity to reliably meet demand and supply California with refined products.

2.0 Disappearing California Refineries

At one time California was home to over 40 operating refineries. However, due to high operating and regulatory compliance costs, a harsh political environment, conversions to bio and renewable fuels, and Governor Newsom's 2020 directive banning the sale of new internal combustion vehicles in the state, the number of refiners has declined by 84% from 43 in 1982 to just 7 survivors in 2026 (estimated). As Chevron Upstream President Andy Walz noted, "I think it's been a tyranny of about 25 years to get the refining business to leave California."[4] If left uncorrected, more refinery closures are likely to follow for the 2027 to 2031 period.

Exhibit 2.0



(Source: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=8_NA_8O0_SCA_C&f=A)

California refineries were designed to process the state's predominantly heavy crude oil and are configured to produce the state-specific CARBOB gasoline and ultra-low-sulfur diesel fuel. CARBOB and ultra-low sulfur diesel fuels (CARB ULSD) are the result of California's regulatory-mandated air quality mandates, which are the strictest in the world. Because of their unique formulations most out-of-state refineries cannot produce CARBOB or CARB ULSD without costly retrofits and retrofits. Because of California's mandated special gasoline formula, there are only a handful of refineries outside of California in the world that can or will produce it.

[4] U.S. News & World Report. (2025, September 23). *California trying to keep oil and gas firms from leaving the state.* Fox Business. https://www.foxbusiness.com/economy/california-trying-keep-oil-gas-firms-from-leaving-state

Exhibit 3.0

CALIFORNIA REFINEIRES		Existing	Projected 2026
CA Refinery Capacity- CARBOB Fuels Only	**Location**	**2025**	**2026**
Southern California Refineries			
Marathon Petroleum Corp., Los Angeles Refinery*	Los Angeles	365,000	365,000
Chevron U.S.A. Inc., El Segundo Refinery	Los Angeles	285,000	285,000
PBF Energy, Torrance Refinery	Los Angeles	160,000	160,000
Phillips 66, Los Angeles Refinery**	Los Angeles	100,000	0
Valero Energy, Wilmington Refinery	Los Angeles	85,000	85,000
Sub-total:		**995,000**	**895,000**
Northern California Refineries			
Chevron U.S.A. Inc., Richmond Refinery	NorCal	245,271	245,271
PBF Energy, Martinez Refinery	NorCal	156,400	156,400
Valero Energy, Benicia Refinery	NorCal	145,000	0
Kern Energy, Bakersfield Refinery	Kern Co.	26,000	26,000
Sub-total:		**572,671**	**427,671**
Grand Total-Refinery Capacity- B/D		**1,567,671.00**	**1,322,671.00**
Gallons Per Barrel = 42		65,842,182.00	55,552,182.00
Total Production- Gasoline Conversion Ratio = 49.64%		**32,684,059.14**	**27,576,103.14**
Percentage Loss in Gasoline Production			-15.62%

(Source: CEC)

Collectively, inclusive of refineries that have converted to renewable fuels and with the loss of the Phillips 66 and Valero refineries, California will have lost close to 21% or 6.2 million gallons a day of its in-state gasoline production capacity since 2023. Based on current projections, California could possibly lose more refineries between 2027 and 2032, resulting in further substantial reductions in in-state gasoline production and further price increases.

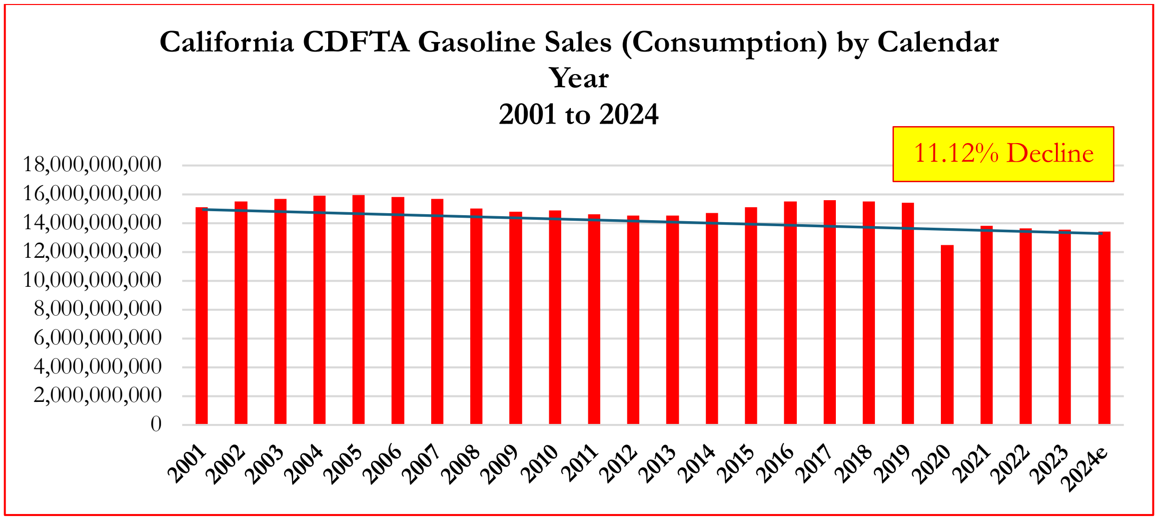
To compensate for the imbalance in demand (consumption) and in-state production of gasoline, California has been forced into importing tens of millions of barrels of refined products from refineries in China, India, Saudi Arabia, and South Korea, demonstrating the state's ongoing and growing vulnerability to supply disruptions, geopolitical unrest, weather, labor disruptions, vessel availability, and foreign dependence. For example, in 2024, California imported most of its jet fuel from China predominantly through the Port of Los Angeles, demonstrating the state's increased reliance on foreign-sourced fuels produced in regions with inferior environmental standards. Today, India is also a source of jet fuel.[5] Both India, and especially China, represent potential political and economic conflicts with national policies and U.S. national security interests.

<u>Gasoline demand in the Golden State has not declined</u> anywhere near the rate anticipated by state agencies such as the CEC and CARB. Rather than the steep annual declines originally forecasted by the CEC and CARB under overly optimistic electrification scenarios, real-world demand for gasoline in California is falling at less than 2% per year. In fact, since the low point in 2020 due to the pandemic, gasoline demand in California has increased by 7.5%.[6] Jet fuel consumption, which is the fastest

[5] U.S. Energy Information Administration. (n.d.). *Company level imports.* U.S. Department of Energy. https://www.eia.gov/petroleum/imports/companylevel/
[6] *Fuel Taxes Statistics & Reports.* (2025). Ca.gov. https://cdtfa.ca.gov/taxes-and-fees/spftrpts.htm

growing fuel segment in California is expected to increase over 25% by 2040 to 125,000,000 barrels per year. [7]

Exhibit 4.0



(Source: CDFTA)

The combination and consequences of these events implies that for decades to come, and well into the latter half of the twenty-first century, California will still need a robust crude oil supply chain and operating refinery system to meet fuel needs even as EV adoption continues. The currently mandated total phaseout of in-state oil production by 2045 is increasingly implausible and irresponsible given these structural realities and the fact that oil and gas provides 8% of California's GDP.[8] California will still need its oil pipeline and refinery infrastructure well into the latter part of the 21st century to remain a viable economy. Ending all California drilling and oil production by 2045 is increasingly unlikely and impractical. Jets require fuel, roads are made of asphalt, and touch screens use hydrocarbon molecules.

3.0 The Collapse of California Pipelines

Refineries are the customers for crude oil which, in California, is delivered via maritime transport or in-state pipelines. Pipeline transportation of crude oil and finished products such as gasoline, is the most efficient and cost-effective method of movement. According to the U.S. Department of Transportation, pipelines are the safest method to transport petroleum products.[9] According to the U.S. Department of Transportation, "it would take a constant line of tanker trucks, about 750 per day, loading up and moving out every two minutes, 24 hours a day, seven days a week, to move the volume of even a modest pipeline. The railroad equivalent of this single pipeline would be a train of 225, 28,000-gallon tank cars."[10]

Today's pipelines are highly regulated and engineered to exact standards. A crude oil and finished fuels pipeline will integrate advanced technologies with continuous operations to monitor safety and environmental impacts. In the U.S., pipelines and pipeline operations are highly regulated and fall

[7] California Energy Commission. (2024, November 7). *Transportation Energy Demand Forecast: Major Updates and Results* (Prepared by A. Freeman, N. Saxena, & F. Kabir; TN No. 259930). 2024 Integrated Energy Policy Report Update, Docket No. 24-IEPR-03. https://efiling.energy.ca.gov/getdocument.aspx?tn=259930
[8] California Governor's Office. (2021, April 23). *Governor Newsom takes action to phase out oil extraction in California.* https://www.gov.ca.gov/2021/04/23/governor-newsom-takes-action-to-phase-out-oil-extraction-in-california/
[9] *General Pipeline FAQs*. (n.d.). PHMSA. https://www.phmsa.dot.gov/faqs/general-pipeline-faqs
[10] *General Pipeline FAQs | PHMSA.* (2019). Dot.gov. https://www.phmsa.dot.gov/faqs/general-pipeline-faqs

under the purview of various federal, state, and local agencies, including the Pipeline and Hazardous Materials Safety Administration. In California, the California Department of Conservation's Geologic Energy Management Division (CalGEM) and the California Office of the State Fire Marshall (OSFM) oversee oil and gas pipelines.[11] As codified in California Regulations sections 1774, 1774.1, and 1774.2, California has the strictest standards for oil and gasoline pipeline construction, testing, and maintenance in the world. California Regulations 1722, 1722.9, 1773.1, and 1775 provide for some of the most rigorous environmental protection standards in the world as related to oil and gas production.

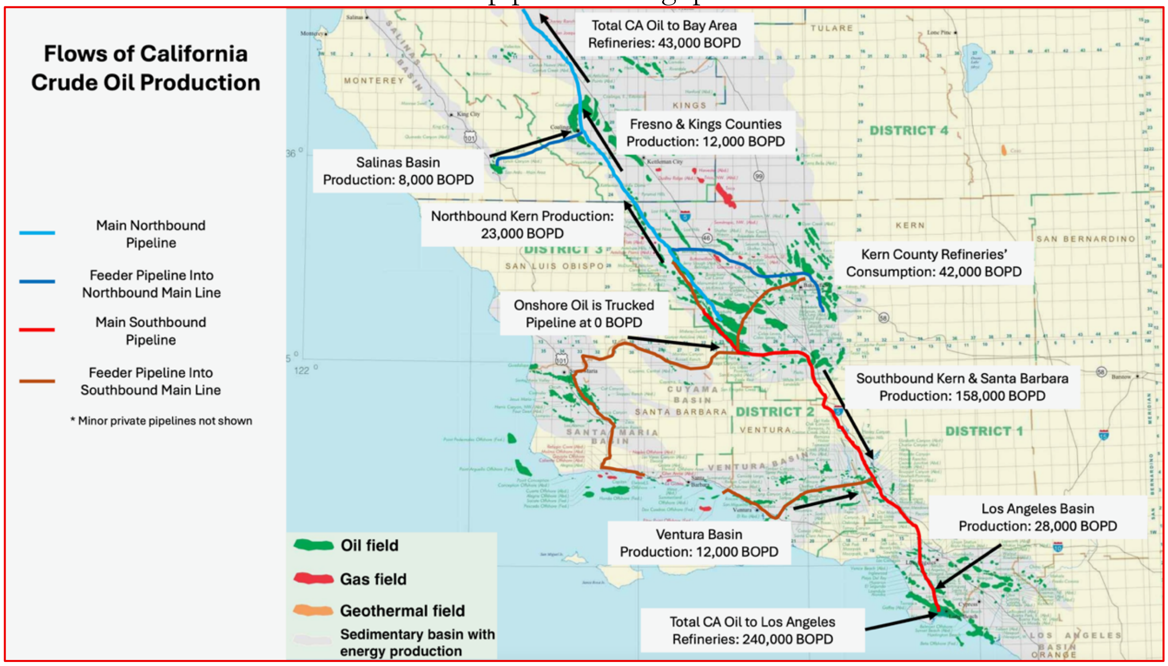
Notably, the same pipelines used for the movement of crude oil could also be configured to transport multiple fuel types, such as all grades of conventional gasoline, jet fuel and kerosene, heating oils, multiple grades of CARBOB, and ultra-low sulfur diesel fuels. Moving different fuels through the same pipeline is accomplished in large batches, with extensive "clean-outs" occurring between each batch of products. As clean-outs are mandatory and essential to the proper and safe operation of the pipelines, they must be carefully scheduled and coordinated.

Although California has no in-bound crude oil or gasoline pipelines, the state does have an extensive network of intrastate pipelines that connect oil producing regions and maritime ports to refineries. There are two major intrastate pipeline systems which connect and move San Joaquin Valley (SJV) production: (1) the primary northbound artery is the San Pablo Bay (SPB) pipeline, and (2) the Plains Pipeline 2000 and PBF Line M70 pipelines which compose the southern artery. Feeding these two major pipelines are multiple smaller "gathering" lines. Collectively, these pipelines have the capacity to transport 410,000 barrels of crude oil daily, distributed 51% northbound on the Crimson SPB pipeline and 49% southbound on the Plains 2000 and PBF M70 lines. Of critical note, Crimson's SPB pipeline is the only major northbound line feeding refineries from the SJV.

As shown in Exhibit 5.0 below, California produces crude oil from regions located in Northern and Southern California, as well as offshore from wells located in federal waters and is transported by a series of pipelines to refineries in Northern and Southern California.

[11] California Department of Conservation. (n.d.). *Pipelines and facilities*. https://www.conservation.ca.gov/calgem/for_operators/Pages/Facilities.aspx#:~:text=Generally%2C%20CalGEM%20regulates%20all%20pipelines,used%20for%20transportation%20to%20refineries.

Exhibit 5.0: Current crude oil production regions in Southern California along with daily refinery and pipeline throughput



(Source: Various & Authors)

In Northern California, the refinery and pipeline network was originally configured around crude production from Kern, Kings, Fresno, and Monterey Counties, particularly the heavy crude grades found in the San Joaquin Valley (SJV). Three large Northern California refineries survive and operate today: Chevron Richmond (which now has no pipeline connections and relies entirely on tanker imports), PBF Martinez, and Valero Benicia. The PBF Martinez and Valero Benicia refineries are supplied by the San Pablo Bay (SPB) pipeline, a subsidiary of Crimson Midstream, LLP. The SPB "Crimson" pipeline is the only remaining northbound crude pipeline in the entire state. With the imminent closure of the Valero Benicia refinery, PBF Martinez will be the sole surviving Bay Area refinery with pipeline access to California-produced crude. However, the PBF Martinez refinery is positioned to accepts both maritime and pipeline crude stock and its operations are not contingent on pipelines and are not reliant on the SPB pipeline.

Southern California, by contrast, has six major refineries—Chevron El Segundo, Marathon Los Angeles, PBF Torrance, Valero Wilmington, Kern Energy, and San Joaquin Refining—all of which are pipeline-connected to SJV crude. With Valero's Benicia closing, Los Angeles will have 5.7 times more pipeline-connected refining capacity than the entire Bay Area. This structural imbalance, together with refinery economics, strongly incentivizes Central Valley producers to ship crude south, where the market is larger, more competitive, and more flexible.

Exhibit 6.0

CALIFORNIA REFINERY	INTRASTATE CRUDE OIL FEEDS		
Northen California	**Pipeline**	**Pipeline Capacity**	**Maritime- 100%**
Chevron- Richmond	NA	NA	Maritime- 100%
PBF Marathon- Martinez	SBP-Crimson	210,000 b/d	Maritime
Valero- Benecia	SBP-Crimson	210,000 b/d	Closing
Southern California			
Chevron- El Segunda	Plains- 2000	135,000 b/d	Maritime
PBF - Torrance	M70	70,000 b/d	Maritime
Valero- Willington	Plains- 2000	135,000 b/d	Maritime
Marathon- LA	Plains- 2000	135,000 b/d	Maritime- Limited
Kern. Energy	Plains- 2000	135,000 b/d	None
San Roaquin	Plains- 2000	135,000 b/d	None
Note: Combined Plains capacity is 235,000 b/d for all lines.			

In the past few months, approximately 43,000 barrels per day were transported via from Kern, Kings, Fresno and Monterey Counties to Northern California refineries—about 20% of pipeline capacity, which is far below both economic and operational breakeven levels. Now, only about 29,000 barrels per day are shipped in the SPB pipeline. These small volumes are increasing operating costs per barrel transported resulting in a $2.0 million a month loss for Crimson Midstream, the owner/operator, as well as incurring substantial costs in deferred maintenance. Crimson Midstream, has notified the Governor that they will need to shut the pipeline down without relief. Based on current information, the shutdown of the SPB pipeline is imminent and could be as early as December 31, 2025.

Exhibit 7.0

CALIFORNIA PIPELINE	INTRASTATE CRUDE OIL FEEDS		
Pipeline	**Pipeline Capacity**	**Current Estimated Pipeline Capacity Utilization**	**Status**
Northbound			
SBP-Crimson	210,000 b/d	**15%**	Shutdown Imminent
Southbound			
Plains- 2000	135,000 b/d	82%%	Active- Stable
M70	70,000 b/d	87%	Active- Stable

If the SPB pipeline is shut down, Northern California will need to import crude oil via more shipments from maritime tankers or over-the-road tanker truck oil from Southern California. Each of these options would add $.50 to $1.00 to the price of gasoline and risk higher spikes due to geopolitical, equipment and transportation issues.

In California, as well as other states, tanker trucks are heavily regulated and require special licenses to operate. Gasoline tanker trucks come in various sizes and configurations. Fuel tanker trucks are usually non- or low-pressure liquid bulk carriers. In contrast to the massive volumes of barrels or gallons that are carried by rail tankers and maritime vessels, tanker trucks carry between 200 to 250 barrels of oil, or 8,400 to 10,500 gallons, depending on configuration and DOT rating. By example, to replace 100% of the SPB pipeline capacity using a large tanker truck would require and add up to 222 more trucks a day to California's already stressed highway and freeway system.

The lack of sufficient in-state crude oil production and the closure of the Valero's Benicia refinery create an imbalance which is the root cause of the crisis facing the SPB (SPB) pipeline. Once one of several northbound options, the SPB pipeline is forecasted to handle only about 29,600 bopd for November, down 70.4% from an average of more than 100,000 bopd just a few years ago. The current volume only 15%-16% of the system's 210,000 bopd design capacity which is 46% below generally acknowledged economic breakeven levels. Because pipeline costs are roughly 80% fixed, this collapse in volume has driven the tariff sharply upward and threatened the pipeline's financial viability. In early 2025, Crimson Midstream (the pipeline operator) filed a tariff based on 62,700 bopd or 63% of capacity throughput that would support a $3.61/bbl tariff rate.[12] But as volumes rapidly fell—due to PBF shifting to marine supply for Martinez, Chevron permanently rerouting its SJV crude to El Segundo, falling in-state crude production, and general producer preference for southern pipelines—the economics of the SPB pipeline rapidly deteriorated.

In June 2025, and in response to decreasing volumes and escalating financial losses, Crimson California Pipeline, L.P., the owner and operator, initiated an emergency filing with the California Public Utilities Commission (CPUC) seeking am increase in its tariff rate to $3.75/bbl. Analysis of the higher tariff indicates that it may help slightly but will assure continuity of operations. The higher tariff rate will, at best, only cover the cash operating expenses and lessen losses, it will address or alleviate LTIP and CorEnergy expenses. With actual volumes now at 29,600 bopd, the "true" cashflow breakeven tariff is $4.42/bbl, which is substantially above regulatory and producer tolerance limits. Stated differently, increasing the tariff to $4.42 does not provide an attractive economic value to the producers and would, in most likely terms, force more maritime shipments northward with any cost associated with the increase in pipeline tariff granted to Crimson, simply passed along to the California consumer who already pays the highest prices in the nation for gasoline.

By contrast, the Plains Line 2000/63 (southbound) charges $1.68–$2.36/bbl.[13] Furthermore, as a captive private pipeline, PBF's Plains-2000, which moves crude oil to its Torrance refinery, has marginal costs below $1.00/bbl.

Anecdotally, crude oil producers have repeatedly told Crimson that $3.75–$4.00/bbl is the maximum economically tolerable northbound tariff; anything above that risks making SPB commercially unattractive and potentially obsolete. Shippers have already nominated zero barrels for December 2025, citing uncertainty about final tariffs, and singling declining confidence in SPB's financial stability, and the looming closure of Benicia. PBF and Valero have both requested the return of their line fill, signaling their withdrawal from the system. Crimson Midstream has informed shippers it potentially has sufficient funds to operate through early 2026, but without regulatory action or increased volumes, the SPB pipeline's future is uncertain.

4.0 Consequences of Losing Refineries & Pipelines

As a result of California's policies, refiners and pipeline operators have exited the state or are considering exiting the state. From 2023, and because of refinery conversions to renewable fuels and the loss of two refineries, California's in-state gasoline production will have dropped by 6.2 million gallons a day. Other than SB 237 and AB 30, which are insufficient, the only public plan to replace the self-inflicted loss is of in-state crude oil and fuel supply to import gasoline and more crude oil from non-U.S. sources using foreign flagged tanker vessels. That solution exposes both the California

[12] E&E News. (2025, November 21). *California approves rate hike for distressed oil pipeline operator*. https://www.eenews.net/articles/california-approves-rate-hike-for-distressed-oil-pipeline-operator/
[13] Plains All American Pipeline. (n.d.). *Tariffs*. https://www.plains.com/customers/tariffs/

consumer and U.S. national security to greater and more complex geopolitical and economic risks. It also contributes to additional carbon emissions and severe air pollution, especially in port communities and in the regions where the crude oil is produced and refined overseas.

Importing refined petroleum products, such as CARBOB gasoline or California reformulated diesel, presents its own set of substantial economic, safety, and environmental drawbacks that compound the challenges facing the state's crude supply chain. While California already brings in some finished products, relying more heavily on imports exposes consumers and the state to a much more volatile, complex, and expensive supply system. The specialized transportation fuels that are required in California are costlier to produce out of state because most refineries elsewhere are not configured to meet California's unique CARBOB specifications. To do so, would require a refiner to invest heavily in new equipment and processes to undertake special blending, reformulation, or batch-processing campaigns, all of which increase production costs and result in premium pricing. These costs would be passed directly through to California consumers in the form of higher retail pump prices. As the finished gasoline would be produced by refineries located in counters such as India, China, Iraq, and even Russia, the California Legislature and <u>Governor would have very little leverage and virtually no powers to enforce environmental and human rights standards</u>, let alone prices.

Additionally, since in-state refiners are voluntarily exiting California, the state must rely more extensive on the marine transportation of finished gasoline and diesel fuel. Finished fuels are more dangerous and hazardous to transport than transporting crude oil due to the higher volatility and flammability of these refined products. As finished fuel tankers are smaller than crude oil tankers, there will be increased tanker calls into Los Angeles/Long Beach, Richmond, Martinez, and Benicia; all of which bring elevated risks of environmental damage, port congestion, marine accidents, fires, and spills; events that disproportionately threaten coastal communities, minority populations, port workers, and sensitive wildlife habitats.

Environmentally, importing refined products from producers in India, China, South Korea, and other distant countries increases greenhouse gas emissions at multiple stages. For example, crude oil production often occurs in regions with weaker pollution controls than California; marine voyages transporting finished fuels across the Pacific for 40 to 49 days emit significantly more CO_2 per gallon delivered than crude oil transported via pipeline; and increased tanker traffic raises the risks of both catastrophic spills and chronic ecological degradation. This includes ballast-water impacts, vessel-strike risks to marine mammals, and long-term shoreline contamination. In effect, <u>shifting from in-state refining of California crude to greater reliance on imported finished fuels would externalize pollution while intensifying local environmental hazards, all while raising prices and reducing energy security.</u>

The loss of two major refineries and the collapse of a major northbound pipeline will undoubtedly <u>increase consumer prices; the only issue is by much</u>. The larger issue is that California will be increasing its dependency on foreign sources supplying crude oil and gasoline to the Golden State, and, to a certain extent abdicating its energy security to those nations, as well as impacting U.S. national security. With the expected substantial increase in inbound maritime tanker traffic, as well as the potential for more over-the-road gasoline and oil tanker trucks on California's roads, California will be increasing global GHG emissions and negatively contributing to climate change and environmental destruction.

The consequences of these actions, the inherent inadequacies of SB 237 and AB 30 as solutions, and the lack of leadership to fully address the crude oil and gasoline security needs of the state on part the Legislature and Governor, have created an urgent reality in California. The inability or failure of Sacramento and state regulators to fully address and prevent the loss of the Valero refinery and the collapse of the SPB pipeline will have significantly negative implications to California. Specifically:

- Northern California refineries are losing access to in-state crude even though fuel demand remains relatively steady.
- Northern California will most likely experience severe price increases which would be disproportionate to those in Southern California.
- The surviving Northern California refineries will be 100% dependent on waterborne crude oil supplies.
- The impact of SB 237 for increasing crude oil supplies would be severely limited by the loss of the SPB pipeline as the remaining southbound pipelines are operating in the 80%+ capacity and there is little space to accommodate any new SB 237 production of significant volume.
- Southern California continues to dominate pipeline-connected refining, drawing San Joaquin Valley crude south.
- Southern California will experience consumer price increases, as well, but not to the extreme as those in Northern California.
- California's total greenhouse (GHG) emissions and air pollution, both locally and globally will increase; thus, contributing to climate change and environmental degradation.
- California will have no control or leverage over the operations, emission, and human resource practices, and prices of foreign gasoline producers, who will likely charge a premium.
- If sourced from India, California may be importing jet and gasoline fuels produced from Russian crude; thus, California consumers will be financing, to some extent, Russia's aggression and war against Ukraine.
- If sourced from China, California may be importing jet and gasoline fuels produced from Iranian and Venezuelan crude oils; thus, California consumers will be financing, to some extent supporting rogue regimes and drug cartels.
- As California is home to over 40 military installations, the loss of refineries and pipelines creates increased vulnerabilities to the fuel supplies to military bases in the state.
- As collateral consequence of California's actions and inability to effectively address the loss of refining and pipeline assets, neighboring states Arizona and Neveda will most likely be adversely affected.

If the SPB pipeline shuts down, the consequences cascade across the state. Northern California would lose its only pipeline access to California-produced crude. PBF Martinez would have to increase reliance on tanker imports, raising costs, emissions, and Bay Area marine traffic. Chevron Richmond—already reliant on foreign crude—would become even more exposed to geopolitical price risks. At least 15,000 barrels per day of SJV crude that currently can only reach refineries via SPB pipeline would have to move by truck. Based solely on the loss of 15,000 b/d, around 67 more trucks a day would be required worsening roadway congestion, increasing emissions, and exposing marginalized communities to higher air pollution burdens to compensate for the collapse of the SPB pipeline.

Meanwhile, Central Valley producers would be left with only two southbound pipelines, both of which already operate at relatively high utilization. Any outage—such as the Plains Pipeline 2022 shutdown—

would instantly strand large volumes of SJV crude, forcing shut-ins and costing producers millions. This would also undermine the explicit goals of SB 237, which aims to preserve California's remaining production base and prevent unnecessary interruptions in crude oil supply to prevent price spikes.

5.0 The Blueprint for Ensuring California Gasoline Security & Price Stability

California's oil production and gasoline refinery infrastructure are at a significant crossroads. Unfortunately, years of over regulation and political demonization has now left California with limited choices; either: (1) continue the current path and risk significantly higher gasoline prices, supply shortages, and higher unemployment, or (2) acknowledge that the policies that have contributed to the potential for critical shortages need to be addressed and changed…now.

The Governor, Legislature and CEC have told the public that passage of SB 237 for increasing in-state oil production, and AB 30 which allows for the sale of E15 gasoline, as the centerpieces of their legislative solution, will alleviate gasoline supply insecurity, moderate consumer prices and stabilize the markets. Unfortunately, SB 237 is too little and too late, and AB 30 is overly optimistic and borderline unrealistic in its claims. At best, SB 237 and AB 30 will be of some value but are largely inadequate to address the potential supply insecurities, national security implications, and anticipated increases in consumer gasoline prices associated with declining in-state crude oil production. the loss of two refineries, and the collapse of a vital pipeline.

Properly addressing California's impending gasoline crisis will require a more comprehensive and practical business approach and significant regulatory changes. Within the very near short term, options are limited for the Golden State. SB 237 does not take effect until January 2026. While it is a positive step in the right direction by the Governor and State Legislature, it is doubtful that 2,000 wells could be drilled and brought into production in 2026 at rates sufficient to increase California's oil production to necessary levels to save the State from its pending gasoline and crude oil insecurity issues.

For decades the sale of E15 in California was unlawful until the closing of two refineries and the real possibilities of considerably higher consumer gasoline prices in the state. The passage of AB 30 promising a $0.20 reduction in retail prices as promoted by the Governor's office, is unrealistic and somewhat improbable. The study, which the Governor's office cited but failed to disclose, was financed by the Renewable Fuels Association.[14] Although the "math" may be correct, the analysis is devoid of practicality and does not consider major factors such as adoption rates, capital costs for new equipment, and transportation costs, all of which would be included in the price of fuel to the consumer. Furthermore, the study assumes that E15 would be exempt or be subject to lower LCFS costs as a major part of the estimated savings. There are no E15 gasoline retailers in the state and it is doubtful that there will be 100% adoption of E15 as a fuel for all internal combustion gasoline vehicles, as assumed by the authors of the study. At best, the adoption of E15 might save the consumer $0.06 to $0.086 a gallon but it would also increase fuel consumption as E15 yields 1 to 3% less miles per gallon. Stated differently, it will require more E15 gasoline to travel the same miles versus E10, thus requiring more fuel while the state is losing refinery capacity.

[14] California, S. of. (2025, October 2). *Governor Newsom Signs bill expanding fuel options to cut gas prices.* Governor of California. https://www.gov.ca.gov/2025/10/02/governor-newsom-signs-bill-expanding-fuel-options-to-cut-gas-prices/

Other than importing more crude oil and gasoline from non-U.S. foreign sources such as Iraq, China, South Korea, and others using more non-U.S. maritime vessels for supplying products to California, and the limited prospects of SB 237 and AB 30, California's Governor, Legislature, and agencies, such as the CEC and CARB, have not yet revealed publicly any comprehensive and well-reasoned strategy to provide for gasoline security and price stabilization.
Based on our research, we present three possible solutions for California's government created conundrum.

5.1 Solution 1- State Financial Aid. The short-term options for California are extremely limited. Time is essential as one refinery has ceased operations, a second is shutting down within 120 days, and the only northbound pipeline, Crimson, is on the verge of collapse within 60 days. One option could include using taxpayer funds or the state's credit to provide Crimson Midstream, the owners of the SPB pipeline, roughly **$25 million per year emergency subsidy** to keep SPB operating. Spread across California fuel consumption, this cost is only about **0.036 cents per gallon**—far less expensive than the $0.50–$1.00 per gallon increases likely if Northern California is forced to rely more heavily on non-U.S. foreign oil and gasoline imports, an armada of maritime tankers, and upwards of 200 or more over-the-road tanker trucks a day. Transportation costs alone for imported gasoline and jet fuels range $0.123 to $0.17 a gallon which would be added to the retail price at the pump or to airline ticket cost. But even if the subsidy was provided, it would only be temporary and likely be politically unpopular. Afterall, taxpayer monies would be offered to an industry that has long been demonized by the Governor and Legislature as "ripping off" consumers.[15] Significantly, California taxpayer subsidies or state-arranged financing may address the short-term financial losses of the owner-operator, Crimson Midstream, but it does not provide for necessary volumes needed for substantiable operations and does not solve the structural mismatch between supply and refinery needs.

5.2 Solution 2- Increase Production. Over the longer term and as the most practical strategy for securing the California's gasoline and crude supplies and price stability is a statewide system solution which rebalances crude flows. This approach is sustainable and would provide operational certainty for the producers and surviving refiners, as well as ensuring supply security and price stabilization for consumers. Under this strategy, rebalancing would be accomplished by introducing new in-state crude oil production capable of supplying Southern California refineries. The introduction of new in-state production, above and beyond that of SB 237, would free up SJV crude to flow north through the Crimson SPB pipeline, thus, avoiding imminent failure and preserving the pipeline.

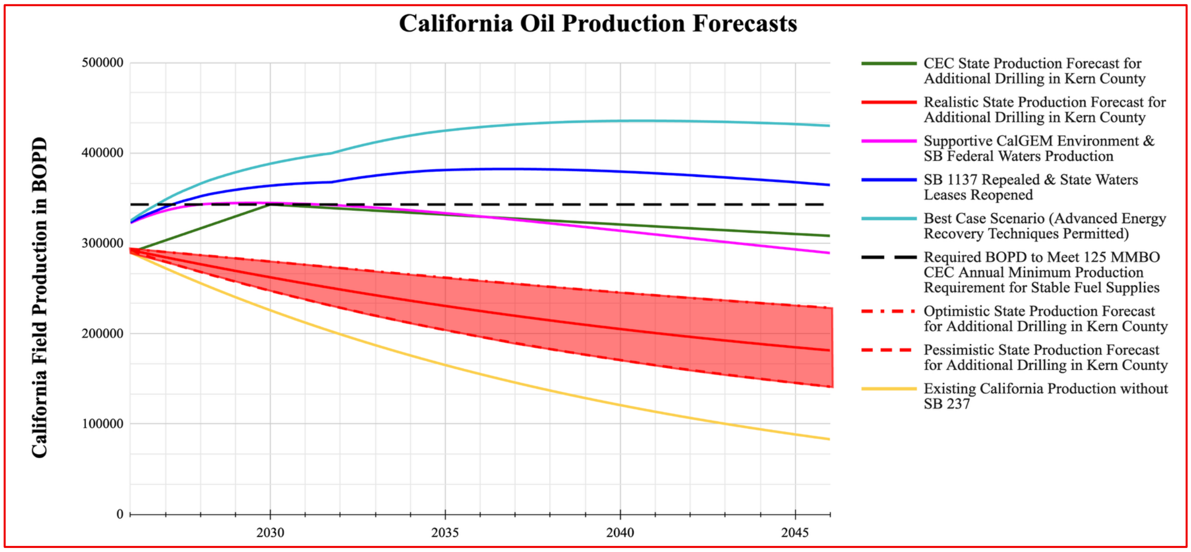
By directing this offshore production south, Southern California refineries would require fewer barrels of crude oil from the SJV thereby allowing a substantial portion of Kern County crude which is highly compatible with Bay Area refinery designs, to be redirected north. This would restore SPB volumes to sustainable levels, stabilize the tariff, and preserve the state's refinery and pipeline resilience.

The key to keeping the SPB pipeline viable and open is to send more Kern County oil north and utilize more of the existing capacity. However, presently, Southern California refineries and pipelines need all the Kern oil they can get. Exhibit 8.0 below summarizes 7 models of California oil production under various scenarios. As indicated in Exhibit 8.0 below, even under the most generous scenario, the implementation of SB 237 alone will not satisfy California's crude oil needs nor sustain the

[15] Office of the Governor of California. (2022, December 5). *Governor Newsom unveils price gouging penalty on Big Oil's excessive profits to protect Californians from being ripped off.* https://www.gov.ca.gov/2022/12/05/governor-newsom-unveils-price-gouging-penalty-on-big-oils-excessive-profits-to-protect-californians-from-being-ripped-off/

operations of the SPB pipeline. Even with additional drilling permits from SB 237, existing regulations and low crude oil prices will hamper meaningful increases in oil production.

Exhibit 8.0



(Source: Authors [16])

New Kern production stimulated by SB 237 will not be enough to stem the natural decline of Kern County oil production in the current low crude price environment and due to existing regulatory roadblocks, which will not be resolved by SB 237. New production is needed. Production models indicate that over the longer term, as California production in the SJV continues to decline, additional offshore resources (Santa Ynez Unit (SYU)), expanded South Ellwood output, and new onshore developments in the Los Angeles Basin could maintain the balance needed to support a long-term orderly transition to lower consumption. Allowing more advanced technologies and reverting to commonly-accepted production practices and techniques in the SJV could help increase production and reserves there. Still, without restoring the Las Flores pipeline system and increasing SYU offshore production and in Los Angeles, California has no realistic pathway to maintaining the north–south crude oil balance that keeps the refinery system functioning and allows the pipeline to survive. Without rebalancing, California will most likely experience an acceleration of refinery closures, skyrocketing consumer prices, gasoline supply issues, and contribute to environmental harm.

5.3 Solution 3- Presidential Intervention. California's policies and actions affect the U.S. we are already seeing the impact of more maritime tankers being diverted to California from east coast states and the need to import considerably more jet fuel from China and India to sustain commercial air operations in the Golden State. This is especially dangerous during times of geopolitical unrest as, for example, relying upon China for jet fuel in a national emergency, increased military operations, or the need to intervene on behalf of Taiwan would be highly precarious. Because California is essential to the U.S. economy and sits as the vanguard of U.S. defense and military readiness for Asia Pacific, it may require the President's intervention to assure gasoline security and price stability in California. Accordingly, one action that the President could take would be to invoke the Defense Production Act, as the means to protect vital crude oil production, refineries and pipelines. Given California leadership's inability to provide a clear and comprehensive plan for preserving refinery and pipeline

[16] Silvi, J. B., Rector, J. W., & Mische, M. A. (2025, October). *A Study of SB 237 to Stabilize Oil Production in California.*

assets and safely increasing in-state crude oil production, invocation of the Defense Production Act by President Trump would be in the best in the interests of the nation and state.

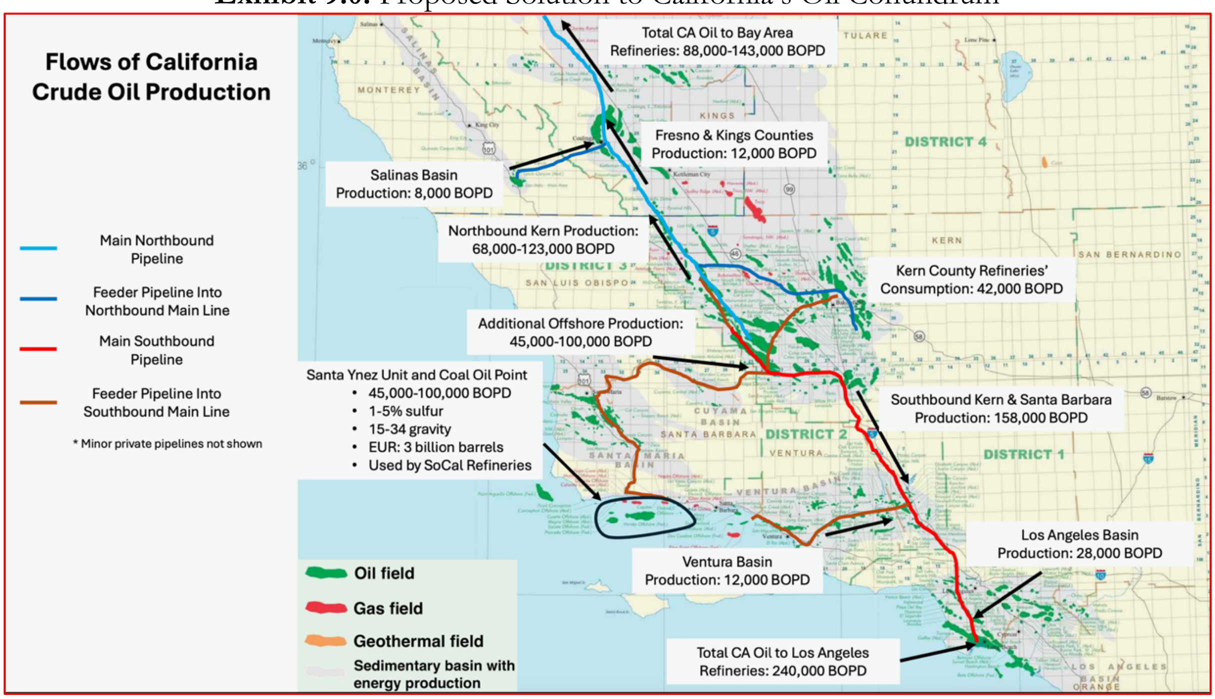
6.0 Recommended Action Steps

Of the three options outlined above, California's most viable option is to increase in-state crude oil production. The best, and essentially only way to achieve this benefit is to reopen the Las Flores Canyon pipeline system on the Central Coast and increase offshore crude oil production.

The Las Flores Canyon Pipeline has historically transported crude from offshore Santa Barbara fields (such as the Hondo, Pescado, Sacate, and South Ellwood oil fields) to refineries in Southern California. Restoring it would immediately provide 45,000 barrels per day of clean, low-decline California crude suited for SoCal refinery configurations. Additional development in areas with existing naturally occurring toxic oil seeps, could increase production up to 100,000 barrels per day and reduce natural toxic seep emissions. Additionally, there are currently 350,000 barrels of SYU crude oil in storage tanks which could be delivered into the California system within a few days' notice, or over 10 times the current daily volume moving through the Crimson SPB pipeline.

As indicated in Exhibit 9.0, and based on our estimates, the activation of the Santa Barbara and offshore SYU fields and connecting pipelines will immediately provide up to 350,000 barrels of already extracted crude oil from the SYU oil fields and provide an additional 45,000 to 100,000 barrels of daily production. This oil can be directed south to the Los Angeles area refineries thereby freeing up tens of thousands of barrels per day of Kern County oil compatible with Northern California refineries to be redirected north to the surviving PBF-Martinez refinery. The rebalancing that is achieved through additional production should avert the impending pipeline shutdown and does not require taxpayer dollars or a state-financing.

Exhibit 9.0: Proposed Solution to California's Oil Conundrum



(Source: Authors)

As older fields in the San Joaquin Valley decline, new production from areas like the South Ellwood field, the Los Angeles Basin and SYU offshore can come online to keep California's energy system viable. An added benefit is that managed production reduces large, naturally occurring oil and gas seeps. Offshore oil seeps in the Santa Barbara Channel and onshore seeps in Los Angeles release crude and toxic hydrocarbons into the environment in an uncontrollable manner. By producing oil in a controlled manner, underground pressure is relieved and surface seepage drops, which improves air and water quality while keeping oil in the state's energy supply chain.

Failing to address the loss of refineries and pipelines by California leadership will only result in the exiting of other refiners and pipeline operators, heavier reliance on foreign sources, greater exposure to geopolitical events and force majeure, increased GHG emissions, additional air pollution, and considerably higher consumer prices. If indeed, that is the case, then as a last resort, President Trump should consider interceding by invoking the Defense Production Act as a means of protecting the surviving refiners and pipeline operators. That action would be in the best interests of the nation and Californians.

7.0 Conclusion

Reopening the Las Flores Canyon pipeline system is the only immediately reasonably viable, abundantly obvious, long-term solution to California's gasoline supplies insecurities. Increasing in-state production keeps refineries running, preserves the San Pablo Bay Pipeline, strengthens energy security, mitigates port pollution near minority communities, reduces tanker traffic, and lessens dependence on foreign oil. At the same time, it would potentially reduce natural seep emissions, providing a real environmental benefit. This approach makes California's oil infrastructure more practical, reliable and resilient as the state moves through the multi-decade energy transition.

In this study, we demonstrated how increasing crude oil production in certain regions in California will preserve and sustain both refineries and pipelines. Failure to act and failure to increase in-state crude oil production will only accelerate the exit of California refineries from the state, increase global GHG emissions, force greater reliance on foreign suppliers, increase consumer prices, and diminish U.S. national security.

Attachment G:
Proposed Draft Environmental Assessment

U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

DRAFT ENVIRONMENTAL ASSESSMENT
and
PROPOSED FINDING OF NO SIGNIFICANT IMPACT

Special Permit Information:	
Docket Number:	PHMSA-[]
Requested By:	Sable Offshore Corp.
Operator ID#:	
Original Date Requested:	January 22, 2026
Issuance Date:	[ ]

I. INTRODUCTION

The National Environmental Policy Act (NEPA), 42 United States Code (USC) §§ 4321 – 4375 *et seq*., and U.S. Department of Transportation (DOT) Order No. 5610.1D, requires in certain cases the Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS) to analyze a proposed action to determine whether such action would have a significant impact on the human and natural environment. PHMSA ordinarily analyzes special permit requests for potential risks to public safety and the environment that could result from our decision to grant, grant with additional conditions, or deny the request. As part of this analysis, PHMSA evaluates whether grant of a requested special permit would impact the likelihood or consequence of a pipeline failure as compared to the operation of the pipeline in regular compliance with the federal pipeline safety regulations. PHMSA's environmental review associated with a special permit is limited only to impacts that would result from granting or denying the special permit.

This Draft Environmental Assessment (DEA) and Finding of No Significant Impact (FONSI) is being developed for Sable Offshore Corp.'s (Sable's) January 22, 2026 Application for a special permit, to waive compliance with the requirements of 49 CFR § 195.452(h)(4)(iii)(H) and address the limited effectiveness of cathodic protection along segments CA-324 and CA-325 of Sable's

Santa Ynez Pipeline System (SYPS) (the "Proposed Alternative").[1] This DEA specifically analyzes environmental impacts associated with the special permit, and finds that grant of Sable's request presents no significant environmental impacts.

II. PROJECT DESCRIPTION

Sable operates the Santa Ynez Pipeline System (SYPS), an interstate pipeline facility consisting of, among other things, a Part 195-regulated emulsion line that transports oil from offshore oil production platforms to an onshore processing facility known as the Las Flores Canyon Processing Facility (LFC), which itself is part of the SYPS, and two downstream Part 195-regulated pipeline segments, CA-324 and CA-325.[2]

Sable requested a Special Permit specifically for CA-324 and CA-325 (the "special permit segments"). Sable requested this special permit to: (1) seek waiver of 49 CFR § 195.452(h)(4)(iii)(H), requiring remediation of corrosion of or along a longitudinal seam weld within 180 days of discovery, and (2) implement the terms of a Consent Decree entered in Civil Action No. 2:20-CV-02415 by the U.S. District Court for the Central District of California, which provides, among other things, that the segments obtain a State Waiver for the "limited effectiveness of cathodic protection" from the California Office of the State Fire Marshal (OSFM) prior to resuming petroleum transportation through the segments.

The Consent Decree contemplated that the owner of segments CA-324 and CA-325 would obtain State Waivers from OSFM—rather than special permits from PHMSA—because, at the time of entry of the Consent Decree, CA-324 and CA-325 were considered part of an intrastate pipeline facility and were regulated by OSFM pursuant to its state certification with PHMSA under 49 U.S.C. § 60105(a). Sable previously applied for and obtained State Waivers for CA-324 and 325

[1] The prior operator of segments CA-324 and CA-325 referred to them as Line 901 and 903, respectively.

[2] Crude oil has been transported from offshore oil production platforms through the SYPS to LFC since May 2025. Petroleum flowed through the entire SYPS, including segments CA-324 and CA-325, until May 19, 2015, when a rupture occurred along segment CA-324 approximately 100 yards north of Highway 101 and 0.25 miles west of Refugio State Beach in Santa Barbara County, California. The SYPS has remained in an active state, but petroleum did not flow through it, from the time that 2015 rupture occurred until May 2025.

from OSFM on December 17, 2024, and on February 11, 2025, PHMSA notified OSFM that it had no objection to its issuance of the State Waivers and the State Waivers became effective.

On November 26, 2025, Sable notified PHMSA of its determination that the Santa Ynez Pipeline System, including segments CA-324 and CA-325, constitutes an interstate pipeline facility under the PSA. On December 17, 2025, PHMSA concurred with Sable's November 26, 2025, determination that segments CA-324 and CA-325 are part of an interstate pipeline facility (SYPS). As a result, PHMSA now has exclusive pipeline safety jurisdiction over CA-324 and CA-325 pursuant to 49 U.S.C. § 60104(c), including the authority to modify and/or waive compliance with any applicable federal pipeline safety regulations.

On December 19, 2025, Sable applied for an Emergency Special Permit from PHMSA with respect to segments CA-324 and CA-325, which previously were regulated by the State Waivers. Sable's application proposed "substantially the same measures … that have already been reviewed and approved by [OSFM] through issuance of [the] State Waivers." Consistent with the scope of the State Waivers, Sable's application sought (1) regulatory relief from 49 C.F.R. § 195.452(h)(4)(iii)(H) and (2) "a special permit from PHMSA for [the] limited effectiveness of cathodic protection" as provided under the Consent Decree. On December 23, 2025, PHMSA issued an Emergency Special Permit that carried forward substantially the same conditions that were in the two previously-issued State Waivers.

IV. BACKGROUND AND REGULATORY REQUIREMENTS

Existing PHMSA Requirement: The following is a summary and description of the regulatory requirements that Sable would be required to follow with respect to segments CA-324 and CA-325 if the special permit were not issued.

Section 195.452(h)(4)(iii)(H) provides that certain corrosion of or along a longitudinal seam weld be mitigated within 180 days of discovery. However, on September 12, 2025, PHMSA published a revised interpretation clarifying that corrosion merely coincident with a longitudinal seam does not need to be mitigated per section 195.452(h)(4)(iii)(H).

Consent Decree Requirement: Appendix B of the Consent Decree requires, as a condition of resuming petroleum transportation through segments CA-324 and CA-325, obtaining a State Waiver for both segments from OSFM "for the limited effectiveness of cathodic protection."

On December 17, 2024, OSFM issued State Waivers for segments CA-324 and CA-325. On February 11, 2025, PHMSA notified OSFM that it did not object to the issuance of the State Waivers.

On December 17, 2025, PHMSA concurred with Sable's November 26, 2025, determination that segments CA-324 and CA-325 are properly classified as part of an interstate pipeline facility (i.e., the SYPS), rendering the segments as subject to PHMSA's pipeline safety jurisdiction as opposed to OSFM.

On December 23, 2025, PHMSA issued an Emergency Special Permit for segments CA-324 and CA-325 and included conditions substantially consistent with OSFM's State Waivers.

Level of Existing Environmental Review: On July 18, 1984 the US Department of the Interior (DOI) and the California State Lands Commission (CSLC) prepared a draft joint Environmental Impact Report/Environmental Impact Statement ("Draft EIS"), pursuant to NEPA and the California Environmental Quality Act (CEQA) to analyze the construction, operation, and ongoing repair and maintenance of segments CA-324 and CA-325.[3]

Following public comment, in January 1985, the DOI and CSLC prepared a Final Environmental Impact Report/Environmental Impact Statement ("Final EIS") with respect to the proposed construction, operation, and ongoing repair and maintenance of segments CA-324 and CA-325. Both the Draft EIS and Final EIS also analyzed the environmental effects of identified routing

---

[3] The Draft EIS analyzed the "Celeron / All American Pipeline Proposal," which consisted of the construction, operation, and ongoing repair and maintenance of an approximately 1,200-mile pipeline to transport Outer Continental Shelf and other locally produced crude oils from the Santa Barbara and Santa Maria Basins to McCamey, Texas. Segments CA-324 and CA-325 were analyzed in the Draft EIS as part of the "Celeron segment" of the proposal. The operational life of these segments were assumed to continue until "the availability of crude oil" for use in the segments was exhausted. (*See* Draft EIS, p. 2-35.)

alternatives and those associated with a "no project alternative", to determine the significance of these potential impacts, the avoidability of these impacts, and potential mitigative measures. Collectively, this DEA refers to the Draft EIS and Final EIS as the "Original EIS".[4]

Separately, PHMSA previously conducted an EA in conjunction with the integrity management (IM) rule at 49 CFR 195.452, which governs the frequency of integrity assessments and prescribes a schedule of anomaly repairs for covered pipelines not otherwise subject to a special permit (see Appendix A). PHMSA's EA associated with that rulemaking determined that hydrostatic testing could be associated with minor adverse environmental impacts, including:

- slight disturbance of the right-of-way to uncover short segments of the line,
- potential for leaks of water and oil residue mixture, and
- disposition of the spent water test medium that mixes with residue oil.

PHMSA's EA also determined that internal inspections have minor adverse environmental impacts, including:

- possible need to install pig launchers and receivers and valves or other appurtenances to accommodate inspection tools;
- possibility of additional localized disturbances along the right-of-way for excavations to examine and repair identified anomalies.[5]

PHMSA determined that these adverse impacts would be limited to small areas on the applicable pipeline segment's right-of-way and would not involve additional vegetation or environmental disturbances beyond the equipment site. PHMSA concluded that these adverse impacts would not be significant, and determined that:

> the combined impacts of the initial baseline assessment (pressure testing or internal inspection), the subsequent periodic assessments, and additional preventive and mitigative measures that may be implemented to protect

[4] The Draft EIS and Final EIS can be accessed at http://cosantabarbara.app.box.com/s/gc3vhh8ns8aiwketnq35vwbehnhre672 and https://cosantabarbara.app.box.com/s/lkl9oo9xdsaangevdp6pasfo0cmimvlt, respectively.

[5] PHMSA-RSPA-2000-7408-0034 at 23.

> high consequence areas will result in positive environmental impacts. The number of incidents and the environmental damage from failures in and near high consequence areas are likely to be reduced. However, from a national perspective, the impact is not expected to be significant for the pipeline operators covered by the final rule.[6]

The IM rule EA also determined that acceleration of integrity assessments of affected segments would "only shift[] the improved integrity assurance forward for a few years for most high consequence areas."[7]

PHMSA NEPA Review for Special Permit: As discussed above, the Original EIS contains a comprehensive environmental impacts analysis for the initial construction, operation, and ongoing repair and maintenance of segments CA-324 and CA-325. PHMSA's environmental analysis for this special permit is limited to an evaluation of the significance of impacts associated with the Proposed Alternative (grant of the special permit) compared to those that would result under the No Action Alternative. The No Action Alternative refers to the scenario in which the existing segments CA-324 and CA-325 operate without a special permit, ongoing operation and maintenance activities occur as contemplated by the Original EIS and under the current federal pipeline safety regulations, and with any other construction, repair, maintenance, or inspection

[6] 65 Fed. Reg. at 75405.

[7] *Id*. Apart from these previous NEPA reviews, the US Department of Interior Bureau of Safety and Environmental Enforcement ("BSEE") also recently determined that BSEE's decision to approve an extension of time to resume operations on the 16 federal offshore leases comprising Sable's Santa Ynez Unit will not significantly affect the quality of the human environment under NEPA. See US Dept. of Interior Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement, "Finding of No Significant Impact, ExxonMobil/Sable Offshore Corporation Lease Extension of the Santa Ynez Unit – Environmental Assessment," May 2025 (available at https://www.boem.gov/sites/default/files/documents/environment/environmental-assessment/2025_0528_SableEA_FONSI_508c.pdf). Santa Ynez Unit production activities send oil through the SYPS for eventual downstream transportation.

activities that have been completed along segments CA-324 and CA-325 prior to PHMSA's issuance of the special permit.[8]

In addition, PHMSA personnel separately reviewed information regarding the location of segments CA-324 and CA-325 and the conditions in the proposed special permit. PHMSA personnel previously determined that the proposed special permit would achieve at least an equivalent measure of safety as under the Part 195 regulations.

In addition, this EA does not evaluate alternatives beyond PHMSA's mandate. PHMSA is obliged to evaluate special permit requests and is responsible for facilitating pipeline and hazardous materials safety. Therefore, the EA only analyzes reasonable, foreseeable impacts of specifically the Proposed Alternative (i.e., granting the special permit), and not other activities such as the full scope of operating and conducting repair and maintenance activities along segments CA-324 and CA-325, which was fully evaluated in the Original EIS. A summary of the alternatives assessed for purposes of this DEA is below:

Alternative 1: No Action Alternative

The No Action Alternative involves denial of the special permit. Any transportation of petroleum through CA-324 and CA-325 would occur without waiver of § 195.452(h)(4)(iii)(H) or performing the conditions of the special permit, as otherwise contemplated under the Original EIS and Part 195.

Alternative 2: Proposed Alternative

The Proposed Alternative is the grant of the special permit and petroleum transportation through segments CA-324 and CA-325 in accordance with the special permit.

---

[8] These include, among other things, the installation of numerous safety valves and real-time transient model (RTTM) leak detection system to reduce spill volumes, performance of integrity assessments and repairs of identified anomalies pursuant to the Consent Decree's specifications, and spike hydrostatic testing pursuant to the State Waivers, each of which lower the risk of a pipeline failure.

VI. OVERVIEW OF SPECIAL PERMIT CONDITIONS

The special permit requires, among other things, fracture toughness testing, spike hydrotesting, more frequent integrity assessments and direct examinations, and more stringent anomaly repair criteria than under Part 195. Sable's implementation of and compliance with the special permit's conditions does not provide for or allow any expansion in capacity or new or expanded physical infrastructure along segments CA-324 or CA-325, or construction activity beyond standard operational and maintenance activities that would occur within these segments' already-disturbed operational corridor as contemplated in the Original EIS.

Some of the activities contemplated in the special permit's conditions already have been completed prior to the grant of this special permit, including fracture toughness testing and spike hydrotesting. Moreover, multiple integrity assessments and substantial anomaly repairs have also been performed by Sable along segments CA-324 and CA-325 prior to the effective date of the special permit.

VII. ENVIRONMENTAL REVIEW

1) <u>Land Use and Ownership</u>

a. Baseline Condition (Under No Action Alternative)

Segments CA-324 and CA-325 parallel US Highway 101 along Santa Barbara County's southern coast, until CA-325 turns north toward the Sisquoc Pump Station and then continues east toward the Pentland Station terminal in Kern County, California. The route crosses primarily grazing land between side canyons containing riparian vegetation, as well as oak woodland, rangeland, and irrigated cropland. There are also mountainous portions along the segments' route, and coastal and eastern foothill areas. Portions of these areas have experienced forest and range fires, particularly during dry years and under strong easterly wind conditions.

Recreational facilities surrounding or in proximity to segments CA-324 and CA-325 include Refugio and Gaviota State Parks, which include beaches and campgrounds. Beyond Gaviota Pass, the segments enter the Los Padres National Forest, in which various recreational activities occur, ranging from hunting, camping, and off-roading.

The Original EIS evaluated potential impacts to land use and recreation based on several criteria, and determined that some potential land use and recreation impacts could be significant, such as adherence to Santa Barbara County's Local Coastal Program due to crossings in Gaviota State Park. (Draft EIS, p. 4-76; Final EIS, p. 3-5.) The Original EIS noted, however, that the segments would pass through a "low-use" area of Gaviota State Park, and therefore may be consistent with the policy at issue. (*Id.*) Moreover, the route through Gaviota State Park was not anticipated to significantly affect recreational uses. (Draft EIS, p. 4-77.) Mitigation Measure 28 in the Original EIS required the initial construction of the segments to reduce the applicable construction right-of-way to further limit impacts to Gaviota State Park. (Draft EIS, p. 4-159.) The Original EIS nevertheless determined that impacts related to inconsistencies with the above-identified Policy in Santa Barbara County's Local Coastal Program and disturbance within Gaviota State Park would result in significant and unavoidable impacts associated with initial construction. (Draft EIS, pp. S-10 through S-11.)

Conversely, the Original EIS determined that impacts to agricultural lands would be less than significant. (Draft EIS, p. 4-72.) The Original EIS also determined that, although segments CA-324 and CA-325 would pass through areas susceptible to forest and range fires and therefore could slightly increase the risk of fire, the segments' operational right-of-way – which was anticipated to remain disturbed to accommodate ongoing repair and maintenance activities along the route throughout their operational lifetime – would function as a fuel break and enhance fire suppression access. (Draft EIS, p. 4-76.)

Finally, the Original EIS determined that a major oil spill could result in significant and unavoidable impacts to beaches and water-based recreational opportunities. (Draft EIS, pp. 4-165, S-11.) The Original EIS did not impose any mitigation measures with respect to this impact, but noted that the use of block and check valves along the segments' route would "substantially reduce the oil spill risk." (Draft EIS, p. S-11, fn. 4.) Therefore, operational impacts to land use and recreation were found to be significant and unavoidable.

b. Potential Impacts Associated with Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the previously-issued State Waivers already have been completed. The Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 or CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule). Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments (according to the more stringent repair criteria in the special permit conditions), these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting and spike testing, have already been completed.

Moreover, the Proposed Alternative will not alter the segments' existing oil transmission capacity, route, or facilities so as to introduce new impacts related to land use and recreation such as agricultural land conversions, providing uncontrolled access to previously inaccessible areas, or affecting forest fire or wildfire risks, beyond those already considered in the Original EIS. Nor would the Proposed Alternative produce any further impacts related to conflicts with land use policies limiting pipeline crossings at environmentally sensitive habitat areas or recreational areas beyond what was already determined in the Original EIS. As such, other land use impacts (other than impacts related to potential oil spill impacts, as described below) associated with the Proposed Alternative would not be significant.

The Proposed Alternative would further *reduce* impacts to recreational resources due to potential oil spills as compared to the impacts considered in the Original EIS, and will reflect no change to these impacts from the current condition. The Proposed Alternative's heightened inspection, monitoring, testing, maintenance, and repair requirements collectively will reduce the risk of an oil spill and minimize the magnitude of any such spill should it occur relative to the initial construction, operation, and ongoing repair and maintenance of segments CA-324 and 325 as analyzed under the Original EIR/EIS. Compliance with the conditions of the special permit provide that segments CA-324 and CA-325 will be operated in accordance with inspection and repair standards that are more stringent than required under Part 195.

In conclusion, the Proposed Alternative does not present significant land use impacts beyond those considered under the Original EIS, the Part 195 regulations, or as established through the State Waivers.

2) <u>Cultural Resources</u>

a. Baseline Condition (Under No Action Alternative)

The Original EIS identified the presence of cultural resource sites within segments CA-324 and CA-325's right of way, including lithic scatters, bedrock millingstones, rock shelters, campsites, habitations, quarries, pit houses, and burial sites, among others. The Original EIS concluded that such cultural resource sites would be exposed to potential direct and indirect impacts resulting from actual surface disturbance during pipeline "construction and maintenance activities" and potential future disturbances based on a general intensification of land uses surrounding the sites. (Final EIS, pp. 3-10 through 3-11.) The Original EIS concluded that compliance with the National Historic Preservation Act's inventory, treatment plans, and Section 106 consultation processes (which required consultation with the State Historic Preservation Office) would "ensure that the effects of the pipeline construction on cultural resources are fully considered as required by law." (Final EIS, p. 3-10.)

The Original EIS imposed Mitigation Measure 30, which required the pipeline operator to comply with a cultural resources inventory and treatment plan to be finalized by federal and state land management agencies, including the State Historic Preservation Office, before construction commenced. (Draft EIS, p. 4-159, Final EIS, p. 3-7.) The Original EIS required that the plan would include an intensive cultural resource survey, site-specific mitigation measures, data recovery programs, archaeological monitoring, and cooperation with appropriate Native American groups. (Draft EIS, pp. 4-159 through 4-160; Final EIS, pp. 4-13 through 4-14.) The Original EIS ultimately determined that impacts to cultural resources affected by construction of segments CA-324 and CA-325 would be significant, unavoidable, and permanent (due to the need to conduct ongoing repair and maintenance along each segments' right-of-way during the pipeline's operational lifetime).

b. Potential Impacts Associated with Proposed Alternative

Activities associated with upgrading the safety features of the segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, performing hydrostatic testing pursuant to the previously-issued State Waivers, and installing safety valves already have been completed. The Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 or CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule).

Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments (under the more stringent repair criteria in the special permit), these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting and spike testing, have already been completed.

Sable will continue to comply with Mitigation Measure 30. Similarly, the Proposed Alternative will not alter the segments' existing route or facilities so as to introduce new impacts to cultural resources. The Proposed Alternative will not result in any significant impacts to cultural resources beyond those contemplated under the Original EIS.

3) <u>Biology, Endangered Species, and Habitat</u>

a) Aquatic Biology

i. Baseline Condition (Under No Action Alternative)

The Original EIS analyzed the significance of potential impacts related to the initial construction, operation, and ongoing repair and maintenance of segments CA-324 and CA-325 to aquatic biology based on whether critical habitat would be affected by construction on a long-term basis or whether a major oil spill during operations would impact important spawning or rearing areas for important fish, be toxic to a large portion of important resident fish populations, or occur in a small stream or backwater areas of a larger stream. (Draft EIS, p. 4-38.)

The Original EIS determined that no significant adverse impacts to aquatic biology would occur during construction due to the limited and temporary nature of construction activities. (Draft EIS, p. 4-42.) However, the Original EIS also imposed Mitigation Measure 8 to further limit potential construction impacts, which restricted the amount of construction equipment fuel and lubrication that could be located near sensitive streams and where construction equipment fueling and lubrication activities could occur. (Draft EIS, p. 4-153; Final EIS, p. 4-6.)

As noted above, the Original EIS also acknowledged that routine maintenance and repair activities would occur in the segments' right-of-way during their operation. For example, the Original EIS incorporated certain draft Oil Spill Emergency Response Plans ("Plans") that contemplated regular inspections to "measure the severity of corrosion and to inspect pipeline defects." (Draft EIS, Appendix H, p. H-37.) The Plans also confirmed that, if required, identified pipeline anomalies would be repaired, "cleaned and recoated" or "removed and replaced," and "faulty … sections of pipe would be replaced as necessary." (*Id.*; Final EIS, RTC 37-4.) Impacts to aquatic biology related to the performance of any such routine repair and maintenance activities would be consistent with the temporary impacts identified during the segments' initial construction phase where impacts to the same aquatic resources occurred. The operator would continue to comply with Mitigation Measure 8 when conducting any applicable construction activities in connection with routine repair and maintenance along segments CA-324 and CA-325.

The Original EIS concluded that a potential oil spill could result in significant and unavoidable impacts to aquatic biological resources during the operational phase of the segments. (Draft EIS, pp. 4-42, S-7.) The Original EIS did not impose any Mitigation Measures to reduce such impacts, but noted that the use of block and check valves along segments CA-324 and CA-325 would "substantially reduce [] oil spill risk" and resulting impacts to aquatic biological resources. (Draft EIS, p. S-7, fn. 4.)

ii. Potential Impacts Associated with Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the previously-issued State Waivers already have been completed. The Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 and CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule). Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments, these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting and spike testing, have already been completed.

The Proposed Alternative is expected to further reduce aquatic biology-related impacts from potential oil spills compared to those analyzed in the Original EIS. The Proposed Alternative's heightened inspection, monitoring, testing, maintenance, and repair requirements collectively will reduce the risk of an oil spill and minimize the magnitude of any such spill should it occur relative to the operation of segments CA-324 and CA-325 as analyzed under the Original EIS. As such, the Proposed Alternative will not result in any significant environmental impacts related to aquatic biology beyond those already contemplated in the Original EIS and Part 195.

b) Terrestrial Biology

i. Baseline Condition (No Action Alternative)

The Original EIS analyzed the significance of potential impacts to terrestrial biology resulting from initial construction, operation, and ongoing repair and maintenance of segments CA-324 and CA-325 based on several criteria, including: whether loss of vegetation productivity during construction would not allow for sufficient ground cover to control soil erosion or have ongoing utility (such as for grazing or agriculture); the loss of special status plant species; impacts to vegetation resulting from operational emissions in exceedance of injury thresholds for sensitive vegetation; impacts to critical habitat or ranges for sensitive wildlife during the season of use; and impacts to special status species. (Draft EIS, p. 4-45.)

The Original EIS determined that construction of segments CA-324 and CA-325 would result in significant adverse impacts to sensitive plant and wildlife species. (Draft EIS, pp. 4-45 through 4-46.) Specifically, construction was anticipated to cause the long-term loss of about 138 acres of oak woodlands, raptor nest failures and lower raptor populations for at least one season, and individual losses of the blunt-nosed leopard lizard, San Joaquin antelope squirrel, and giant kangaroo rat. (Draft EIS, pp. 4-48 through 4-52.)

The Original EIS imposed several mitigation measures to address these impacts. Mitigation Measure 9 required a reduced construction right-of-way of 50-feet at riparian crossings and mandated that development avoid disturbance to sensitive and valuable plant communities where possible. Mitigation Measure 12 prohibited vehicle operation outside the construction right of way. Mitigation Measure 14 required a wildlife biologist to conduct a survey of potential raptor nesting habitat prior to construction and mandated that no active nests be disturbed. Finally, Mitigation Measure 15 required investigations, relocations, and revegetation of habitat for the blunt-nosed leopard lizard and San Joaquin kit fox. Mitigation Measure 15A required that site-specific field inventories be conducted prior to construction by a qualified biologist. (Draft EIS, pp. 4-153 through 4-155; Final EIS, pp. 4-6 through 4-11.) After implementation of these mitigation measures, construction-related losses of riparian woodlands, oak woodlands, and individual blunt-nosed leopard lizards and kit foxes (and their habitats) would remain significant and unavoidable. (Draft EIS, pp. S-7 through S-9.)

The Original EIS acknowledged that routine maintenance and repair activities would occur in segments CA-324 and CA-325's right-of-way during their operational phase. For example, the Original EIS incorporated certain draft Oil Spill Emergency Response Plans that contemplated regular inspections to "measure the severity of corrosion and to inspect pipeline defects." (Draft EIS, Appendix H, p. H-37.) The Plans also confirmed that, if required, identified pipeline anomalies would be repaired, "cleaned and recoated" or "removed and replaced," and "faulty … sections of pipe would be replaced as necessary." (*Id.*; Final EIS, RTC 37-4.) Due to the ongoing performance of such repair and maintenance activities since segments CA-324 and CA-325 were constructed, their right-of-way has remained relatively clear of mature vegetation. Impacts to terrestrial biology related to the performance of any such routine repair and maintenance activities would be consistent with the permanent impacts identified during the initial construction phase because the habitat impacted by any such work would be the same habitat where the Original EIS anticipated ongoing repair and maintenance activities would occur. The operator would continue to comply with Mitigation Measures 9, 12, 14, 15, and 15A as applicable when conducting construction activities in connection with routine repair and maintenance along segments CA-324 and CA-325.

The Original EIS also identified potentially significant impacts to terrestrial biology during segments CA-324 and CA-325's operational phase. Specifically, the Original EIS determined that a potential oil spill could kill vegetation and result in erosion and loss of wildlife habitat and sensitive wildlife species such as the blunt-nosed leopard lizard, San Joaquin antelope squirrel, and giant kangaroo rat, constituting a significant and unavoidable impacts to terrestrial biological resources. (Draft EIS, pp. 4-46 through 4-52.)

ii. Potential Impacts Associated with Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the previously-issued State Waivers already have been completed. The Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 or CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule). Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments, these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting and spike testing, have already been completed.

Sable will continue to comply with Mitigation Measures 9, 12, 14, and 15. As such, impacts to terrestrial biology resulting from construction activities will remain consistent with the significant and unavoidable impacts disclosed in the Original EIS. However, impacts related to the performance of future routine repair and maintenance activities will be reduced as compared to segments CA-324 and 325's initial construction-related impacts because any such future repairs would occur at discrete locations along the already-disturbed segments' routes rather than their entire length.

The Proposed Alternative also will further reduce operational impacts to terrestrial biology due to potential oil spills. The Proposed Alternative's heightened inspection, monitoring, testing, maintenance, and repair requirements as part of the special permit collectively will reduce the risk of an oil spill and minimize the magnitude of any such spill should it occur relative to segments

CA-324 and CA-325's operational phase as analyzed under the Original EIS. Because the Proposed Alternative would not result in increased construction or operational impacts to terrestrial biological resources, the Proposed Alternative will not result in any significant environmental effects related to terrestrial biology apart from those already analyzed and disclosed in the Original EIS or otherwise contemplated under Part 195.

4) <u>Air Quality</u>

a) Baseline Condition (Under No Action Alternative)

Segments CA-324 and CA-325 pass through the South Central Coast and San Joaquin Valley Air Basins of California and are located within Santa Barbara, Kern, and San Luis Obispo Counties. Currently, Santa Barbara County and the portion of San Luis Obispo County in which the segments pass through are in attainment with all National Ambient Air Quality Standards.[9] The San Joaquin Valley Air Basin in Kern County is currently designated as in extreme nonattainment with the 2015 8-hour ozone National Ambient Air Quality Standard (NAAQS), and serious nonattainment with the 2021 PM2.5 NAAQS.[10]

The Original EIS evaluated air quality impacts resulting from the construction and operation of the segments CA-324 and CA-325 by comparing estimated emissions against applicable the NAAQS. (Draft EIS, p. 4-2.) The Original EIS determined that construction-related emissions (primarily resulting from heavy-duty vehicle traffic) would not result in any significant air quality impacts because such emissions would account for a small portion of the background ambient emissions in the surrounding area and any such emissions would be temporary and transient. (Draft EIS, pp. 4-3, 4-5.) The Original EIS also concluded that operation of segments CA-324 and CA-325 and associated pump stations would result in a minor incremental increase in ambient

[9] EPA, "California Nonattainment/Maintenance Status for Each County by Year for all Criteria Pollutants", available at https://www3.epa.gov/airquality/greenbook/anayo_ca.html. These two Counties are listed as in nonattainment or "nonattainment-transitional" pursuant to the 2023 area designations for the California Ambient Air Quality Standards for ozone. See https://ww2.arb.ca.gov/sites/default/files/2024-10/State_2023_O3.pdf.

[10] EPA, "California Nonattainment/Maintenance Status for Each County by Year for all Criteria Pollutants", available at https://www3.epa.gov/airquality/greenbook/anayo_ca.html.

background concentrations of nitrogen oxides, carbon monoxide, hydrocarbons, and sulfur dioxide. As such, no significant impacts related to air quality were anticipated to occur. (Draft EIS, p. 4-5.)

b) Potential Impacts Associated with Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the previously-issued State Waivers already have been completed. The Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 and CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule). Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments, these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting, have already been completed.

Future routine repair and maintenance work conducted under the Proposed Alternative would require substantially less excavation activities than initial construction of segments CA-324 and CA-325, and contemporary construction equipment used in any such repair and maintenance construction activities would likely be more fuel efficient and result in substantially fewer emissions than the construction equipment considered under the Original EIS and used during the initial construction of these segments.

Therefore, the Proposed Alternative would most likely involve substantially less construction emissions than those associated with the initial construction of segments CA-324 and CA-325, which the Original EIS already determined to be less than significant. (Draft EIS, pp. 4-3, 4-5.) Moreover, the Proposed Alternative would not increase these segments' oil transmission capacity beyond that contemplated in the Original EIS, and therefore will not directly or indirectly increase operational emissions at any pump stations or other final delivery points. As noted throughout this EA, segments CA-324 and CA-325 will continue to comply with all applicable mitigation measures and conditions of approval.

In summary, the Proposed Alternative will not result in any significant environmental impacts related to air quality beyond those analyzed and disclosed in the Original EIS.

5) Hydrological Resources and Water Quality

a. Surface Water

i. Baseline Condition (Under No Action Alternative)

The Original EIS analyzed the significance of potential impacts to surface water resulting from the initial construction, operation, and ongoing repair and maintenance of segments CA-324 and CA-325 based on whether: water quality would be degraded below applicable regulatory standards; water discharge quality or quantity modifications would cause a reduction in supply or available habitat; channel geometry would be altered; permanent facilities would be located in a 100-year floodplain; or downstream sedimentation would affect irrigation water control structures. (Draft EIS, pp. 4-30 through 4-31.)

The Original EIS determined that initial construction of the segments would not result in any significant adverse impacts to surface water resources due to the limited and temporary nature of construction activities. (Draft EIS, p. 4-31 through 4-33, S-5, 4-163.) During the segments' operational phase, however, the Original EIS determined that a potential oil spill could result in significant and unavoidable impacts to surface water resources. (Draft EIS, pp. 4-32 through 4-33; S-5.) The Original EIS did not impose any mitigation measures related to such impacts, but noted that the use of block and check valves along the segments' route would "substantially reduce [] oil spill risk" and therefore potential impacts to surface water. (Draft EIS, p. S-5, fn. 4.)

The Original EIS also determined that channel degradation at segment stream crossings could result in exposure of the segments' pipe that that could further increase the risk of an oil spill, constituting a significant and unavoidable impact. (Draft EIS, pp. 4-32 through 4-33, S-5.) The Original EIS imposed Mitigation Measure 5 to address this potential impact, which requires the pipeline operator to check line pipe burial depth on an annual basis at all major crossings, and re-bury the pipeline where channel degradation has reduced the depth of fill to less than the 100-year scour depth. (Draft EIS, p. 4-152; Final EIS, p. 4-5.) Even with the implementation of Mitigation Measure 5, the Original EIS determined that potential oil spill impacts to surface water would be significant and unavoidable. (See Draft EIS, pp. S-5, 4-34.)

ii. Potential Impacts Associated with Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the previously-issued State Waivers already have been completed. The Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 and CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule).

Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments, these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting, have already been completed.

Similarly, the Proposed Alternative will not alter segments CA-324 and CA-325's existing route or facilities so as to introduce new impacts to surface water resources. Sable also will continue to be required to comply with Mitigation Measure 5. Therefore, the Proposed Alternative will not impact new surface waters beyond those analyzed in the Original EIS, and will not involve construction-related impacts to surface water that are different than the less-than-significant impacts analyzed and disclosed in the Original EIS.

The Proposed Alternative also will further reduce surface water-related impacts due to potential oil spills. The Proposed Alternative's heightened inspection, monitoring, testing, maintenance, and repair requirements collectively will reduce the risk of an oil spill and minimize the magnitude of any such spill should it occur relative to the operation of segments CA-324 and CA-325 as analyzed under the Original EIS. Because the Proposed Alternative would not result in increased construction or operational surface water-related impacts, Pipeline Restart will not result in any new or substantially more severe significant environmental effects related to surface water than those disclosed in the Original EIS or otherwise contemplated in Part 195.

b. Groundwater

i. Baseline Condition (Under No Action Alternative)

The Original EIS analyzed the significance of potential impacts to groundwater resulting from the construction, operation, and repair and maintenance of segments CA-324 and CA-325 based on whether aquifers would be altered to adversely affect established water uses or if water quality within any aquifer zone would be degraded by the introduction of oil or other pollutants. (Draft EIS, pp. 4-34.)

The Original EIS determined that the initial construction of segments CA-324 and CA-325 would not result in any significant adverse impacts to deep aquifers. (Draft EIS, p. 4-34.) Similarly, any construction-related impacts to shallow aquifers would be temporary, highly localized, and therefore less than significant. (Draft EIS, p. 4-35.)

During the segments' operational phase, however, the Original EIS concluded that a potential oil spill could result in significant and unavoidable impacts to groundwater resources. (Draft EIS, pp. 4-35, 4-37.) The Original EIS imposed Mitigation Measures 6 and 7 to help reduce this potential significant impact. Mitigation Measure 6 required the operator conduct hydrogeologic investigations along sensitive areas and formulate an Oil Spill Contingency Response Plan based on the results of those investigations. (Draft EIS, p. 4-152; Final EIS, p. 4-5.) Mitigation Measure 7 required the operator to use low permeability backfill near sensitive aquifers to force leaking oil to the surface during the segments' operational phase. (Draft EIS, pp. 4-152 through 4-153; Final EIS, pp. 4-5 through 4-6.) The Original EIS also noted that the use of block and check valves along segments CA-324 and CA-325 would "substantially reduce [] oil spill risk" and therefore potential groundwater impacts. (Draft EIS, p. S-5, fn. 4.) Even with the implementation of Mitigation Measures 6 and 7, the Original EIS determined that potential oil spill impacts to groundwater would be significant and unavoidable. (See Draft EIS, pp. S-6, 4-35 through 4-37.)

ii. Potential Impacts Associated with the Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the State Waivers already have been completed. The Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 and CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule).

Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments, these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting, have already been completed.

Similarly, the Proposed Alternative will not alter segments CA-324 or CA-325's existing route or facilities so as to introduce new impacts to groundwater resources. Mitigation Measure 6's requirement to maintain an Oil Spill Contingency Response Plan informed by pre-construction hydrogeologic investigations conducted before segments CA-324 and CA-325 were constructed will continue to apply to the Proposed Alternative. Similarly, the low permeability backfill installed near sensitive aquifers pursuant to Mitigation Measure 7 will continue to force leaking oil to the surface during operations.

The Proposed Alternative also will further reduce groundwater-related impacts due to potential oil spills. The Proposed Alternative's heightened inspection, monitoring, testing, maintenance, and repair requirements collectively will reduce the risk of an oil spill and minimize the magnitude of any such spill should it occur relative to the operational phase of segments CA-324 and CA-325 as analyzed under the Original EIS. In sum, the Proposed Alternative would not result in increased construction or operational groundwater-related impacts beyond those already considered in the Original EIS and otherwise contemplated in Part 195.

6) **<u>Hazardous Waste and Substance Discharge</u>**

a) Baseline Condition (Under No Action Alternative)

The Proposed Alternative was assessed for impacts arising from hazardous waste or other hazardous materials to determine whether statutes or regulations, such as those under the Resource Conservatory and Recovery Act (RCRA) or Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), apply. Segments CA-324 and CA-325 are not regulated under the Resource Conservation and Recovery Act (RCRA) or the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). The Special Permit Segments are not expected to generate hazardous waste or non-excluded hazardous substances.[11] The EPA lists no superfund sites in the vicinity of the Proposed Alternative.

b) Potential Impacts Associated with Proposed Alternative

---

[11] Petroleum substances, including crude oil, are excluded from the definition of hazardous substances under CERCLA, see 42 U.S.C. Section 9601(10).

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the previously-issued State Waivers already have been completed. Although hydrotesting can generate a waste stream consisting of a water and oil residue mixture, hydrotesting has already been completed and is not a new waste stream specific to the Proposed Alternative. Similarly, the Proposed Alternative will not alter segments CA-324 or CA-325's existing route or facilities so as to introduce new impacts to groundwater resources. Given that segments CA-324 and CA-325 do not handle hazardous waste or hazardous substances, nor does the Proposed Alternative involve the introduction of any activities that would involve hazardous waste or hazardous substances (beyond any already considered under the Original EIS or Part 195), the Proposed Alternative will not produce any significant environmental impacts associated with the discharge of hazardous waste or hazardous substances.

7) <u>Geology, Topography, Climate, and Hazards</u>

a. Baseline Condition (Under No Action Alternative)

The Original EIS concluded that, although some temporary (construction period) and permanent changes to topography would occur from the initial construction and operation of CA-324 and 325, the scale of such changes was sufficiently minor such that no significant impacts related to subsidence and physiology would occur. (Draft EIS, p. 4-15.) Potential impacts related to subsidence and impacts related to paleontology, unique geologic features, and mineral/petroleum resources were determined to be less than significant. (Draft EIS, pp. 4-19 through 4-20.)

The Original EIS associated with the initial construction and operation of segments CA-324 and CA-325 also concluded that potential impacts related to seismicity and faulting, such as impacts from strong ground shaking or surface fault rupture, would be potentially significant in the absence of mitigation. Similarly, the Original EIS determined potential impacts related to slope instability and landslides could be significant unless mitigated. (Draft EIS, pp. 4-15 through 4-19.) Accordingly, the Original EIS imposed several mitigation measures. Mitigation Measures 1 and 3 required detailed geologic, seismologic, and geotechnical studies to be prepared and recommendations to be incorporated into the segments' final design and route. Mitigation Measure 2 required the pipeline design also to incorporate appropriate ground motion parameters. (Draft EIS, pp. 4-150 through 4-151; Final EIS, pp. 4-2 through 4-4.) With the implementation of these mitigation measures, the Original EIS determined that all geology-related impacts would be less than significant. (Draft EIS, p. S-4.). Ultimately, these mitigation measures were implemented as part of initial construction of the segments.

b. Potential Impacts associated with the Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the previously-issued State Waivers already have been completed. The Proposed Alternative will not involve any changes to the segments' existing alignment so as to involve different geologic conditions than those which were implicated by the segments' initial construction. Similarly, the Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 and CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule).

Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments, these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting and spike testing, have already been completed. In short, the Proposed Alternative does not raise significant geological impacts.

8) <u>Noise and Visual Environment</u>

a. Noise

i. Baseline Condition (Under No Action Alternative)

The Original EIS evaluated potential noise impacts resulting from the initial construction, operation, and repair and maintenance of segments CA-324 and CA-325 based on whether project-related noise would exceed adopted state or local standards or a day-night average sound pressure level of 60 dBA at the nearest noise sensitive receptor. (Draft EIS, pp. 4-94.)

The Original EIS determined that the segments' construction noise impacts would be significant and unavoidable at sensitive receptors near their rights-of-way, including at schools, parks, residential subdivisions, and individual residences. (Draft EIS, pp. 4-94, 4-100.) The Original EIS noted, however, that the significance of pipeline construction activities would be lessened (albeit not to a level of insignificance) by the fact that construction activities would be limited to daytime hours when background ambient noise levels are higher. (Draft EIS, p. 4-100.)

The Original EIS also concluded that noise impacts would be potentially significant during the segments' operational phase given the location of pump stations near sensitive receptors. Specifically, it concluded that potentially significant impacts would occur at the Vista del Mar school, which was located near the Gaviota Pump Station. (Draft EIS, p. 4-100.) The Original EIS imposed Mitigation Measure 34 to address this impact, which required the Pump Station to be shielded from the school by a noise barrier such as a berm or structural enclosure. (Draft EIS, p. 4-162; Final EIS, p. 4-16.) Implementation of this Mitigation Measure was determined to reduce the segments' operational noise impacts to a less than significant level. (Draft EIS, p. S-12.)[12]

---

[12] Since construction of the Pipelines, Vista del Mar school has been relocated and is now located farther away from the Gaviota Pump Station.

ii. Potential Impacts Associated with the Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the State Waivers already have been completed. Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 and CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule). Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments, these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting, have already been completed.

The Proposed Alternative will not alter segments CA-324 and CA-325's existing route or facilities or any pump stations so as to introduce new noise-related impacts to sensitive receptors. The Proposed Alternative will not result in significant noise-related impacts.

b. Visual Resources

i. Baseline Condition (Under No Action Alternative)

The Original EIS evaluated potential visual resources impacts associated with the initial construction, operation, and repair and maintenance of segments CA-324 and CA-325 based on whether the proposed facilities would meet visual resource management class objectives and visual quality objectives established by applicable federal agencies. The Original EIS concluded that while the segments' rights-of-way would remain disturbed throughout their operational lifetime, those rights-of-way generally would not be visually evident to people from nearby highways, roadside rest areas, parks, or recreation areas. (Draft EIS, p. 4-88.)

The Original EIS also determined, however, that potentially significant visual impacts would result from construction and operation of segments CA-324 and CA-325. First, significant visual impacts would occur at two locations where right-of-way clearing during construction would be required for the pipeline to traverse the Los Padres National Forest (LPNF). Second, significant visual resources impacts would result from the construction and operation of the Sisquoc Pump Station in the Santa Barbara County. Significant visual resources impacts would occur due to the construction of the permanent, aboveground facilities associated with the pump station, which would permanently degrade the surrounding area's overall visual character relative to its prior undeveloped condition. (Draft EIS, pp. 4-88 through 4-93; Final EIS, p. 3-6.)

The Original EIS imposed Mitigation Measures 31 and 32 in order to mitigate these significant impacts. Measure 31 required screening the Gaviota Pump Station and Sisquoc Pump Station with native shrubs, trees, and/or naturalized masses of evergreen shrubs and trees as appropriate for each site's location and climatic conditions. (Draft EIS, pp 4-160 through 4-161; Final EIS, p. 4-14 through 4-15.) Measure 32 required that the pipeline use a 50-foot construction corridor within the Los Padres National Forest (LPNF), protect existing large diameter trees, feather the edges of the cleared right-of-way, and reseed cleared areas with native species. (Draft EIS, p. 4-161; Final EIS, p. 4-15.) Implementation of these mitigation measures reduced the potentially significant visual resources impacts identified at the Gaviota Pump Station and Sisquoc Pump Station to a less than significant level. (*Id.*, p. 4-165.) Visual resources impacts resulting from the pipeline's construction and operation through the LPNF remained significant and unavoidable. (*Id.*)

ii. Potential Impacts Associated with Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the previously-issued State Waivers already have been completed. The Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 and CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule).

Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments, these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting, have already been completed.

Future repair and maintenance activities (including any such activities within the LPNF) would occur within the segments' existing 50-foot construction corridor where the Original EIS determined visual resources impacts would be significant and unavoidable.

Similarly, the Proposed Alternative will not alter these segments' existing route or facilities so as to introduce new impacts to visual resources. The Proposed Alternative also will not involve work affecting vegetation at the Sisquoc Pump Station. Sable will continue to comply with Mitigation Measures 31 and 32. Therefore, while visual resources impacts would continue to be significant and unavoidable, the Proposed Alternative would not introduce new visual resource impacts beyond those previously analyzed.

The Proposed Alternative therefore would not result in any significant environmental effects related to visual resources beyond those disclosed in the Original EIS.

9) <u>Socioeconomic Impacts</u>

a. Baseline Condition (Under No Action Alternative)

The Original EIS evaluated socioeconomic impacts resulting from the construction, operation, and repair and maintenance of segments CA-324 and CA-325 based on whether: the demand for temporary housing would exceed existing supply during pipeline construction; permanent demand on other infrastructure would be more than 25% of current demand or if temporary demand exhausted the excess capacity in the areas where construction crews would live; the initial construction and operation would result in a change in local tax bases, area population or composition, or employment sector that exceeded 10%; or adequate housing accommodations were not available to support the project within a commuting distance. (Draft EIS, pp. 4-57 through 4-58.)

The Original EIS determined that all socioeconomic impacts related to construction and operation of the segments would be less than significant. Specifically, temporary housing for construction workers was not anticipated to exceed local supply and project operation would not result in excessive changes in local tax bases, area population or composition, or employment sector allocations. (Draft EIS, pp. 4-60 through 4-64.) The Original EIS imposed Mitigation Measure 22, which required the construction period to be scheduled so as not to coincide with peak tourist seasons, to further reduce any potential socioeconomic impacts. (Draft EIS, p. 4-157; Final EIS, p. 4-11 through 4-12.)

b. Potential Impacts Associated with Proposed Alternative

Activities associated with upgrading the safety features of segments CA-324 and CA-325 (such as installing additional safety valves and new leak detection systems), repairing anomalies along the segments to comply with the Consent Decree, and performing hydrostatic testing pursuant to the previously-issued State Waivers already have been completed. The Proposed Alternative is not expected to result in any new construction in areas not previously disturbed by initial construction of segments CA-324 and CA-325 or construction activities along the segments beyond routine repair and maintenance activities analyzed in the Original EIS and contemplated under the current Part 195 regulations (including the IM rule). Although the Proposed Alternative would involve the performance of integrity assessments on a more frequent basis, which may result in the need to perform localized excavations to repair anomalies discovered from such assessments, these activities were already addressed and determined to be insignificant in the IM rule EA, and would likely have otherwise occurred under the No Action Alternative, albeit under a different schedule. Over the long-term, the Proposed Alternative is not anticipated to result in a larger number of excavations than would otherwise result under the No Action Alternative. Other activities under the Proposed Alternative, such as hydrotesting, have already been completed.

As such, there will be no significant socioeconomic impacts in the area associated with the Proposed Alternative.

VIII. PROPOSED FINDING OF NO SIGNIFICANT IMPACT

The activities directed under the Proposed Alternative would not exceed what was already contemplated in prior relevant environmental review, including in the Original EIS and in the IM rule's EA. Moreover, Sable will continue to implement the Mitigation Measures established in the Original EIS, and will continue to comply with applicable laws and permits issued. Accordingly, the Proposed Alternative is determined to not have potential to significantly impact the environment.

The proposed special permit can be found on the Federal Docket Management System located on the Internet at www.regulations.gov under docket no. PHMSA-2025-150.

Completed by PHMSA in Washington, D.C., on: Month Day, Year

Appendix A

Environmental Assessment for Final Rule: Pipeline Integrity Management in High Consequence Areas, Docket No. RSPA 00-7408

163308

RSPA-00-7408-34

Research and Special Programs Administration

U.S. Department of Transportation

Environmental Assessment

Final Rule

Pipeline Integrity Management in High Consequence Areas

for

Hazardous Liquid Pipeline Operators

Operating Less than 500 Miles of Pipeline

Docket: RSPA 00-7408

Preliminary Finding of No Significant Impact

This Environmental Assessment is prepared in accordance with section 102(2)(c) of the National Environmental Policy Act (42 U.S.C. Section 4332), the Council on Environmental Quality regulations (40 CFR Sections 1500-1508), and Department of Transportation Order 5610.1c, Procedures for Considering Environmental Impacts. It was prepared to assist in the Research and Special Programs Administration's (RSPA) planning and decision-making. This document is an update of the original Environmental Assessment prepared in support of the proposed rule (66 FR 15821).

This document concisely describes the RSPA's final rule on integrity management in high consequence areas for certain operators of hazardous liquid pipelines. It also addresses the need for the proposed action, the alternative actions considered, the environment affected by this action, the consequences to the environment of the proposed action and the alternatives, and a list of the agencies and organizations consulted. This Environmental Assessment provides sufficient evidence to determine that the provisions of the final rule are expected to have no significant impact on the environment.

Table of Contents

A. Purpose and Need for Action

The Research and Special Programs Administration (RSPA) believes that pipeline safety regulations address the most important risks to the nation's pipelines, and have served the industry and the nation well. The hazardous liquid pipeline industry has **a** good safety record compared to other modes of transportation. However, pipeline incidents still occur and, on occasion, with serious consequences. Continued improvement in safety and environmental performance is still RSPA's highest objective. RSPA believes that safety programs based only on compliance with the regulations can result in a piece-meal approach to identifying and controlling risks, sometimes neglecting the relationships among different **risk** factors and the potential benefits of coordinated risk control activities. Having operators implement more systematic and integrated approaches to assure pipeline integrity and address the most important pipeline risks offers the greatest opportunity to improve the industry's performance.

Pipeline operators also have strong incentives to ensure the integrity of their pipelines. In addition to the positive safety and environmental benefits, the lost product and unscheduled downtime for repairs following a major incident can significantly impact the company's financial performance, and its ability to satisfy customer commitments. Operators can not afford to have these critical transportation assets out of service for lengthy periods of time in today's competitive business environment. In addition, the damage to the company's public image and reputation, as well as the legal implications of serious incidents, can pose an even broader and longer term negative impact on the company's business operations. For these and other reasons, many pipeline operators have implemented and are continuing to improve more systematic safety and environmental management processes.

A.1 Recent RSPA Pipeline Safety and Environmental Protection Programs

To better understand and promote more comprehensive and integrated approaches to safety and environmental protection, RSPA created the Risk Management Demonstration Program, and the System Integrity Inspection (SII) Pilot Program. These programs encourage and evaluate operator-developed safety and environmental management processes that incorporate operator- and pipeline-specific information and data to identify, assess, and address pipeline risks. These programs, along with the Oil Spill Response Plan Review and Exercise Program, are helping RSPA's Office of Pipeline Safety (OPS) refine its regulatory oversight processes. These processes help to ensure that pipeline operators have effective processes in place to identify the most important risks to the public and the environment, and to develop and implement cost-effective preventive and mitigative actions to manage these risks. These initiatives have validated the importance of focusing resources and establishing higher levels of protection in areas where a pipeline failure could have significant consequences.

Through the Risk Management Demonstration Program and the System Integrity Inspection Pilot Program, OPS has improved its understanding of pipeline operator integrity management systems and activities. This experience has shown that a number of liquid operators have formalized management systems to identify and address the most significant integrity threats to their pipeline systems. In the Risk Management Program, participants perform systematic and comprehensive risk assessments to identify the specific nature and location of the most significant risks posed by operation of their pipeline system. An essential feature of these risk assessments is the integration of information from many diverse sources to fully understand the integrity threats at specific locations on the pipeline. Environmental consequences and the impact on nearby population are explicitly considered in these risk assessments. Through formal, risk-based decision making processes, these companies use the risk assessment results to identify projects and activities that address potential system integrity threats, thereby helping to prevent oil spills. The risk management process also examines the consequences of potential releases and explores opportunities to minimize the environmental and public safety and health impacts should a failure occur. These investigative risk management programs, and the preventive and mitigative risk control activities that evolve from them, supplement the minimum regulatory requirements established in 49 CFR 195 to protect the public and the environment.

The SII Program is focused on developing a more integrity-based approach to OPS inspections. In addition to verifying an operator's compliance with the pipeline safety regulations, OPS is focusing the inspection process on an operator's integrity management processes and activities. By working with the operator, OPS is able to understand and influence the methods and approaches used to integrate integrity assessment data with other pipeline specific information to identify the most significant integrity threats to the system. Specifically, OPS has observed how operators examine in-line inspection data in conjunction with other surveillance and operating data, expected population growth, land use, construction activity along the pipeline, and other information relevant to assuring the integrity of the pipeline in high population areas and in environmentally sensitive areas. Through this interaction OPS is acquiring a broader understanding and a greater confidence that effective programs are in place to address the most significant risks. Similar to the Risk Management Program, the SII Program is emphasizing how operators evaluate their system condition and its risks, and use this information to make sound integrity management decisions.

While these two programs only involve a limited number of operators, OPS discussions with other companies in industry forums and working groups have indicated that formal integrity management programs have become more common, particularly within the liquid pipeline industry. OPS found that many liquid companies are developing more sophisticated and mature integrity management systems, analytical methods, data integration processes, and diagnostic tools. OPS believes the next step is to require all operators to develop and follow at least minimum level integrity management programs.

A.2 Legislative History and National Transportation Safety Board Recommendations

Congress has also directed DOT to consider several initiatives that could improve safety and environmental protection, especially in locations where pipeline failures might have significant impacts to human health and safety and the environment. Specifically Congress has directed DOT to:

- Prescribe standards establishing criteria for identifying gas pipeline facilities located in high-density population areas, and hazardous liquid pipelines that cross waters where a substantial likelihood of commercial navigation exists, are located in high-density population area, or are located in an area unusually sensitive to environmental damage **(USAs)** [49 U.S.C. § 60109(a)(2)].

- Prescribe additional standards requiring the periodic inspection of pipelines in **USAs** and in high-density population areas. The regulations are to prescribe when an instrumented internal inspection device, or similarly effective inspection method, should be used to inspect the pipeline [49 U.S.C. § 60102(f)(2)].

- Survey and assess the effectiveness of emergency **flow** restricting devices (EFRDs) and other procedures, systems, and equipment used to detect and locate hazardous liquid pipeline ruptures, and to prescribe regulations on the circumstances under which an operator of a hazardous liquid pipeline facility must use an EFRD or such other procedure, system, or equipment [49 U.S.C. § 60102(j)].

In addition to these Congressional directives, the National Transportation Safety Board (NTSB) has made several recommendations addressing improved protection for high population and environmentally sensitive areas. These recommendations include:

- Requiring periodic testing and inspection to identify corrosion and other time-dependent pipeline damage.

- Establishing criteria to determine appropriate intervals for inspections and tests, including safe service intervals between pressure testing.

- Determining hazards to public safety from electric resistance welded (ERW) pipe and establishing standards for leak detection systems.

- Establishing requirements for installing automatic or remote-operated mainline valves on high-pressure lines in urban and environmentally sensitive areas to provide for rapid shutdown of failed pipeline segments.

RSPA has initiated several programs and activities in response to these legislative mandates and NTSB recommendations. **As** summarized in Section **A.**1, the Risk Management and SII Pilot Programs have provided an understanding of how these issues can be effectively addressed within the context of a comprehensive and systematic integrity management program that considers the total spectrum of **risks** from pipeline operation, including those risks in locations where the consequences to public health and safety and the environment may be elevated.

RSPA has also undertaken a rigorous and thorough process for developing the criteria to define USAs. This multi-year process involved numerous interactions with other Federal and State agencies, representatives of the hazardous liquid pipeline industry, environmental organizations, and other stakeholders. RSPA published for public comment proposed criteria to define USAs on December 30, 1999 (64 FR 73464). Numerous public comments were received on the proposed criteria (available in Docket # 99-5455).

The proposed USA criteria were also pilot tested to confirm that the proposed USA definition can be used to identify and locate unusually sensitive drinking water and ecological resources using available data from government agencies and environmental organizations. The pilot test identified USAs in Texas, California, and Louisiana - states with a large number of hazardous liquid pipelines, as well as considerable drinking water and ecological resources. The results of the pilot test, as well as the criteria in the proposed USA definition, were reviewed by a team of nationally recognized experts on drinking water and ecological resources. In late 2000, RSPA completed its evaluation of the feedback from the technical peer review, public comments, and the pilot test results. After extensive consultation with other Federal agencies, a final rule defining USAs was issued on December 21,2000 *(65* FR 80530).

RSPA evaluated the potential benefits of EFRDs in limiting the volume of product released following a hazardous liquid pipeline failure. The results were published in "Emergency Flow Restricting Devices Study" in 1991 (available in Docket # PS-133). This study recommended that OPS seek public input on the placement of EFRDs in urban areas, at water crossings, at other critical areas affected by commodity release, and in areas in close proximity to the public outside of urban areas. This study also concluded that remote control and check valves are the only effective EFRDs.

In January 1994, RSPA issued an advance notice of proposed rulemaking (ANPRM) (59 FR 2802) to solicit data from the public through a series of questions primarily concerning the performance of leak detection equipment and location of EFRDs. A public workshop was held in October 1995 to further address the issues associated with requiring EFRDs. These forums raised important concerns about the effectiveness and cost-effectiveness of these mitigative features. It was suggested that the need for EFRDs should evolve from an integrated evaluation of the site-specific conditions and risks facing a particular pipeline location. This evaluation would include assessing the effectiveness of the existing preventive and mitigative activities as well as considering the need for additional preventive or mitigative risk control activities. Especially when considering mitigative actions like EFRDs, the environmental sensitivity of the location is an important factor that must be considered to make the best overall risk reduction decisions. Thus, RSPA deferred proposing regulations requiring EFRD installation until USAs were defined.

RSPA believes that the experience obtained through the Risk Management Demonstration Program, the SII Pilot Program, the USA definition process, and other initiatives has provided a foundation for moving forward with a rule that addresses these Congressional mandates and NTSB recommendations in a comprehensive and integrated manner.

A.3 Interaction with Industry, Other Agencies, and Stakeholders

On October 21, 1999, RSPA issued a Notice (64 FR 56725) announcing a public meeting to discuss the need for additional regulations for natural gas and hazardous liquid lines in high population areas, commercially navigable waters, and areas of the environment that are unusually sensitive to the environment damage (i.e., high consequence areas). This Notice included a conceptual approach to providing improved protection in high consequence areas, and solicited feedback on a number of specific questions relative to this approach. In the Notice, RSPA stated that any process for protecting high consequence areas should include:

- Pipeline-specific assessments in determining the need for additional preventive and mitigative activities;
- *An* assessment approach that considers all **risk** factors and **risk** reduction activities in an integrated manner; and
- Increased assurance that high consequence areas are being protected.

The public meeting was held on November 18 and 19, 1999, in Herndon, Virginia. The primary discussion topics included: the key elements of an effective integrity management program, the extent to which operators now have integrity management programs, and how to validate the effectiveness of such programs. In addition, RSPA obtained feedback and input on a broad array of integrity management issues, including:

- How to characterize and define high consequence areas,
- Key elements of operator integrity management programs,
- Types of information that should be integrated to assure pipeline integrity; and
- OPS review of integrity management programs, including what elements to review and inspect.

A synopsis of the feedback obtained at this meeting, as well as complete transcripts of the formal presentations are available in Docket # 99-6355, and on the OPS home page at http://ops.dot.gov.

On December 22, 1999, RSPA issued a Notice in the Federal Register **(64** FR 71713) announcing an extension of the public comment period to January 17,2000. The availability of an electronic discussion forum was announced to allow interested parties to express their views on integrity management program issues and the need for improved protection in high consequence areas. This Notice also referenced a draft conceptual model for assuring pipeline integrity in high consequence areas, and solicited comments on the draft approach. RSPA received comments from several organizations and individuals. These are available in the Docket # 99-6355, and are summarized in the preamble of the Notice of Proposed Rulemaking (NPRM) announcing the proposed requirements for integrity management programs. *(65* FR 21695, April 24,2000: See additional discussion below).

Following the public meeting, RSPA hosted a number of smaller meetings and conference calls to make sure the broadest range **of** comments and information were considered in drafting the NPRM. Discussion items included the areas that should be considered high consequence areas, reasonable milestones for completing benchmark testing, developing industry standards to support a rule, how a rule should acknowledge differences between the gas and liquid pipeline industries as well as among individual operators, and how best to involve affected communities. These topics were discussed with Interstate Natural Gas Association of America (INGAA) representatives on January 12, American Petroleum Institute (API) representatives on January **13,** National Association of Pipeline Safety Representatives (NAPSR) on January 14, February 15, and March 3, public interest representatives on January 19 and February 29, and the NTSB on February **8.** Minutes from each of these sessions are in the Docket.

After considering the feedback from the public meeting, comments to the Docket, and experience in the Risk Management and SII programs, RSPA elected to implement integrity management requirements for the pipeline industry through a series of rules focused on different objectives. On April 24,2000, RSPA published a Notice of Proposed Rulemaking (NPRM) "Pipeline Integrity Management in High Consequence Areas" (65 CFR 21695). This proposed rule focused on the hazardous liquid industry operators who own or operate 500 or more miles of pipeline. Approximately 87% of the hazardous liquid transportation lines are operated by operators with 500 or more pipeline miles.

A number of individuals and organizations provided comment on the proposed rule described in the NPRM. These comments are available in Docket # 99-6355, and summarized in the preamble to the final rule. In addition to public input, RSPA also continued its consultations with other Federal agencies, including the Environmental Protection Agency, the Department of Justice, and the Department of the Interior. Guidance was also obtained from the Technical Hazardous Liquid Pipeline Safety Standards Committee, RSPA's statutory advisory committee for hazardous liquid pipeline safety. On December 1, 2000, RSPA published a final rule on Integrity Management in High Consequence Areas covering Hazardous Liquid Operators with 500 or More Miles of Pipeline (65 FR **75378).** The key provisions of the final rule are summarized below:

- Operators must identify pipeline segments on their systems where a release could impact a high consequence area. High consequence areas are defined as populated areas, USAs, and commercially navigable waterways.

- Operators must conduct baseline integrity assessments on pipeline segments that could affect high consequence areas. Acceptable methods for assessment include internal inspection, pressure testing, or another technology that the operator demonstrates can provide an equivalent level of understanding of the pipe's condition. Baseline assessments for these pipeline segments must be completed by March 31, 2008, with 50% of the distance assessed by September 30,2004. The highest risk segments must be assessed first.

- Operators must perform periodic integrity assessments on segments that could affect high consequence areas at intervals not to exceed 5 years.

- Operators must develop and follow a written integrity management program that consists of the following elements:

  - a process for determining which pipeline segments could affect high consequence areas,
  - a Plan for conducting the baseline assessments noted above,
  - a process for continual integrity assessment **and** evaluation,
  - **an** analytical process that integrates all available information about pipeline integrity and the consequences of a failure,
  - repair criteria to address issues identified by the integrity assessment method and data analysis (the rule provides minimum repair criteria for certain, higher risk, features identified through internal inspection, as well as time frames in which certain features must be repaired),
  - a process to identify and evaluate preventive and mitigative measures to protect high consequence areas,
  - methods to measure the integrity management program's effectiveness, and
  - a process for review of integrity assessment results and data analysis by a qualified individual.

On March 21,2001, RSPA issued a NPRM (66 FR 15821) to extend the same requirements to protect high consequence areas and establish integrity management programs to all hazardous liquid pipeline operators regulated under 49 CFR 195 (i.e., include those operating less than 500 miles of pipeline). ***An*** Environmental Assessment was prepared in support of this NPRM. This final Environmental Assessment is an update of the previous work.

RSPA received a small number of public comments on the NPRM. After reviewing this input, as well as discussions with other Federal agencies, RSPA has decided that the same requirements for protection of high consequence areas and the development of integrity management programs should apply to all hazardous liquid pipeline operators. Section B of this Environmental Assessment describes these requirements.

In addition to these requirements for integrity management in high consequence areas, there are many other Federal, state, and local government regulations in place to protect sensitive resources. These include regulations to protect drinking water resources, threatened and endangered species, critical habitats for various species, and spawning areas. Areas have been created and designated to protect and maintain aquatic life, wildlife, and various other natural and water resources. Permits, environmental assessments, and consultations with resource experts are required by various Federal, state, and local agencies before a pipeline can be installed or construction to modify or repair an existing line take place. **RSPA's** existing and planned future regulations complement and enhance these other Federal, state, and local government regulations on sensitive drinking water or ecological resources.

A.4 Future **RSPA** Integrity Management Initiatives

RSPA plans to propose additional rules on pipeline integrity management for interstate and intrastate natural gas operators in the near future. **RSPA** has met with representatives of INGAA on January 12, March **29,** April **19,** June 15, July **20,** September **6,** September **19,** October **12.** and December **18,2000** to discuss a variety of issues related to improved integrity management for gas pipelines, including:

- the definition of high consequence areas for gas pipelines;
- integrity assessment technologies for gas pipelines, including "direct assessment";
- inspection frequency;
- data integration and analysis;
- integrity management for low hoop stress piping;
- the level of integrity assurance provided by the current regulations (including high population areas);
- current company practices that go beyond the protection explicitly required in the regulations; and
- future standards to support integrity management.

On February **12** and **14, 2001** RSPA conducted a public meeting in Arlington, **VA** to discuss these subjects and other topics relevant to an integrity management rule for gas pipeline operators. Subsequent to the public meeting **RSPA** synthesized the input received, and issued a Notice to request public comment and input on integrity management concepts related to gas pipelines (June **27,2001;** 66 FR **34318).** This input is currently being evaluated. **RSPA** expects to issue one or more proposed rules for gas pipelines beginning in late **2001.**

RSPA has also initiated dialog with industry and various public interest representatives to explore approaches to improve communication between OPS, pipeline operators, and the communities in which pipeline facilities are located. Initial discussions have focused on strengthening the liaison between public officials and pipeline companies, testing the usefulness of pipeline data provided to public officials, and developing concepts for restructuring the respective roles of federal, state, and local officials, emphasizing the distinction between participation and communication. Meetings were conducted on February 28 and 29, September 17, and October 10, 2000 to begin addressing the multi-faceted communication issue. During a public meeting on February 13,2001, OPS sought additional input on enhancing communication with the public and local officials near pipeline facilities. RSPA is currently considering how to best improve communications between pipeline operators, the government, and local officials

The specific requirements of any future proposed rules related to integrity management for natural gas pipelines and communications, and the environmental impacts associated with these requirements will be considered in their respective rulemaking processes.

B. Description of Proposed Action

On December 1, 2000, RSPA published a final rule establishing new requirements for integrity management in high consequence areas for operators that own or operate 500 or more miles of pipe *(65* FR 75378). RSPA is now establishing similar requirements for the remaining hazardous liquid operators.[1] Under these requirements, high consequence areas covered by this rule are populated areas, commercially navigable waterways, and areas unusually sensitive to environmental damage. (Section D provides more detailed definition and description of high consequence areas.) The final rule establishes new requirements to enhance and validate the integrity of hazardous liquid pipelines in high consequence areas. Furthermore, the rule provides additional assurance that appropriate preventive and mitigative measures are in place to protect these high consequence areas.

The final rule requires operators to develop and implement an Integrity Management Program for all portions of their pipelines that could affect high consequence areas. This Integrity Management Program includes at a minimum:

- the identification of all pipeline segments that could impact high consequence areas,
- a Baseline Assessment Plan to assure integrity of these segments, and
- a framework that identifies how each element of the Integrity Management Program will be implemented.

The operator's Integrity Management Program must include the following elements:

- a process for determining which pipeline segments could affect a high consequence area;
- a Baseline Assessment Plan (as described below);
- a process for conducting periodic integrity assessments and evaluation on those segments that could affect a high consequence area;
- an analytical process that integrates all available information about pipeline integrity and the consequences of a failure (also noted above);
- repair criteria to address issues identified by the integrity assessment method and data analysis;

[1] Throughout the remainder of this Environmental Assessment, wherever "operator" is used in the text, it means hazardous liquid operators operating less than 500 miles of pipeline used in transportation.

- a process to identify and evaluate additional preventive and mitigative measures to protect high consequence areas;

- methods to measure the Integrity Management Program's effectiveness; and

- a process for review of integrity assessment results and data analysis by an individual qualified to perform evaluate integrity assessment results.

Each of these elements must be addressed in the framework.

Operators must follow recognized industry practices in their Integrity Management Program. The pipeline segments that could affect a high consequence area must be identified within nine months of the rule's effective date. The Baseline Assessment Plan and Framework must be documented within one year of the rule's effective date.

The Baseline Assessment Plan delineates the integrity assessment method(s) selected for each high consequence area, the schedule by which these initial integrity assessments will be performed, and the technical basis for integrity assessment method(s) selection and **risk** factors used in scheduling the assessments. The rule requires operators to perform a baseline integrity assessment within seven years after the effective date of the rule for all pipelines that could affect a high consequence area, with 50% of this pipeline mileage being assessed within three and one-half years. In scheduling the baseline assessments, operators are to perform assessments of the highest risk segments first. Operators who have performed and documented integrity assessments in the five years previous to the effective date of the final rule may use these assessments to validate a pipeline segment's integrity if the assessment approach and documentation are consistent with the provisions of the rule. The acceptable methods for conducting the baseline integrity assessment are pressure testing, instrumented internal inspection[2], or other technology that the operator demonstrates can provide an equivalent understanding of the pipe's condition.

In evaluating the results of integrity assessments, operators must integrate information from other relevant sources with the inspection or testing results to fully identify and characterize the potential threats to pipeline integrity. These other information sources might include cathodic protection system data, close interval surveys, results of previous internal inspections, operating and leak history, patrolling reports, exposed pipe reports, etc. From this evaluation, the operator should identify the location, nature, and relative severity of anomalies and defects that could threaten pipeline integrity. Operators will be expected to address the important threats by evaluating and repairing, if necessary, defects or anomalies in the pipe. Operators must use a risk-based approach in prioritizing repair activities, in which any severe defects or damage that have the potential to result in a near term leak or failure are addressed immediately. The rule

[2] The integrity assessment methods used for low frequency, electric resistance welded (ERW) pipe and lap welded pipe susceptible to longitudinal seam failures must be capable of assessing seam integrity and detecting corrosion and deformation anomalies.

provides minimum mitigation and repair schedules and criteria that must be applied for certain, higher risk features identified through internal inspection.

In addition to the initial, baseline integrity assessment, the rule requires that operators periodically reconfirm pipeline integrity in **high** consequence areas through regular integrity assessments. ***An*** operator must perform subsequent assessments of line segments that could affect high consequence areas no later than five years after the previous assessment.[3] Within this five year limit, operators must establish assessment frequencies commensurate with the risk each pipeline segment presents to a high consequence area. In other words, those segments presenting a greater **risk** to high consequence areas would be assessed more frequently than segments presenting lower risk. The risk factors to be considered when selecting integrity assessment methods and establishing a schedule for a particular segment include:

- results of previous pressure testing and internal inspection data and results,
- pipe design, materials, and manufacturing information,
- pipe coating type and condition,
- leak history, and repair history,
- cathodic protection system performance,
- product transported,
- operating stress level,
- local environmental factors that could affect integrity (e.g., soil corrosivity, ground movement potential, and climatic factors),
- current or projected activities in the pipeline vicinity, and
- physical support of the segment such as by a cable suspension bridge.

Guidance for identifying and applying **risk** factors is provided in Appendix ***C*** of the final rule.

---

[3] The rule allows operators to extend the period between integrity assessments to more than five years if a reliable engineering evaluation and other external monitoring activities show the pipe to be in good condition, or if an integrity assessment technology the operator plans to use is not readily available. If the justification for extending the re-assessment period is on an engineering basis, an operator must notify OPS nine months before the end of the five-year interval. If the justification is because of unavailable technology, an operator must notify OPS 180 days before the end of the five year interval.

Besides the integrity assessment provisions of the rule, operators also have to conduct an integrated evaluation of line segments that could affect high consequence areas to understand the greatest risks to these locations. This evaluation must include the results of the integrity assessments along with other information necessary to obtain a complete understanding of the risk contributors to a particular pipe segment. As part of this evaluation, the operator must critically evaluate the effectiveness of existing preventive and mitigative risk control measures, and consider if additional preventive and mitigative actions can improve protection for these areas. The operator must explicitly consider whether the installation of EFRDs or enhancing leak detection system capability is warranted. The need for additional preventive and mitigative measures in high consequence areas must be periodically re-assessed in light of new information such as changes in the pipeline condition, operating parameters, or the nearby population density or environment.

The final regulatory language articulating these requirements is provided in 195.450, 195.452, and the Federal Register Notice establishing the final requirements for operators who operate less than 500 miles of hazardous liquid pipeline.

C. Alternatives Considered

RSPA considered several alternatives in the decision process that led to the final rule. These altematives are summarized below.

1. Take No Action. In this alternative, **RSPA** would rely on the existing regulatory requirements to provide protection for high consequence areas. Without the provisions of the rule, operators would not be required to conduct the baseline integrity assessments, perform an integrated approach to integrity evaluation, conduct periodic reassessments, and consider other preventive and mitigative actions for pipeline segments that could affect high consequence areas. By selecting this alternative, RSPA would not be responsive to the Congressional mandates to consider internal inspection and other protective measures for high population areas and area,; unusually sensitive to environmental damage (see Section A.2).

2. Require Mandatorv Integrity Assessments in All High Consequence Areas Every Ten Years. In determining the practical and appropriate requirements for operators who operate less thar 500 miles of hazardous liquid pipeline, RSPA considered establishing different requirements for conducting the baseline and subsequent integrity assessments than those established for operators operating 500 or more miles of pipeline. Initially RSPA considered allowing up to ten years for this group of operators to conduct the baseline assessments on segments that could affect high consequence areas, and allowing an interval for periodic reassessments of up to ten years. Both of these periods are longer than seven years allowed for baseline assessments, and the maximum five year interval for subsequent assessments that were recently established for operators operating 500 or more miles of pipeline (65 FR 75378). RSPA was initially concerned that operators who operate less than 500 miles of pipeline would not have the financial and technical resources available to comply with the requirements described in Section B. **RSPA** was also concerned that during the initial few years, the demand for internal inspection tools might be more than the inspection device vendors could satisfy (with the simultaneously high demand being placed by operators operating 500 or more miles of pipeline). If internal inspection devices were not available, operators would be forced to conduct hydrostatic testing to achieve compliance - which in some instances might not be the most desirable approach.

During the period leading up to the proposed rule, RSPA reviewed its internal data, talked with several operators, and gathered information from its Regional inspectors who routinely inspect these operators in standard compliance inspections. This investigation showed that many operators who operate less than 500 miles of pipe already perform periodic internal inspection or pressure testing on sizeable portions of their pipeline system (see Section E.1.3). Thus, RSPA's initial assumption about the technical and financial resource capabilities of this group of operators was not valid. Furthermore, new information obtained from vendors of intemal inspection devices indicated that while the demand for these tools will be high, the industry should be capable of satisfying pipeline operators' needs for shorter assessment intervals (see Section B).

Finally, **RSPA's** investigation revealed that a number of the facilities operated by operators with less than 500 miles of pipeline are located near populated areas. Imposing less stringent assessment requirements on these operators would be providing less assurance of pipeline integrity to the public in the vicinity of these facilities than for the public in the vicinity of facilities operated by operators with 500 or more miles of pipeline. Based on **RSPA's** current understanding of industry capabilities and resources, there is no justification to establish requirements which would provide different levels of protection for different populated areas. Thus, RSPA concluded that there was no valid reason to impose different integrity assessment requirements on operators operating less than 500 miles of pipeline, from those established for operators who operate systems with more miles of pipeline.

D. Affected Environment

The purpose of the integrity management rule is to provide additional protection to high consequence areas in the vicinity of hazardous liquid pipelines throughout the United States. The baseline integrity assessment and periodic re-assessments, as well as the additional preventive and mitigative activities that evolve from the operator's integrity management program, apply to the high consequence areas along the operator's system. Thus the primary areas of the environment impacted by this rule are high consequence areas defined as follows:

- A *high population area,* which means an urbanized area, as defined and delineated by the U.S. Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile.

- *An other populated area,* which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.

- A *commercially navigable waterway,* which means a waterway where a substantial likelihood of commercial navigation exists. These waterways are identified in the National Waterways Network, a geographic database created by the National Waterways GIS Design Committee. It is available from the DOT Bureau of Transportation Statistics at http://wuw.bts.gov/gis/ntatlas/networks.html.

- An *area of the environment that has been designated as unusually sensitive to oil spills* (USAs). After completing a multi-year investigation with many agencies, industry, and other organizations, RSPA has published a final definition of **USAs** (65 FR 80530, December 21,2000). The USA definition includes drinking water and ecological resource areas. For drinking water resources, USAs would include:

  - The water intake for a Community Water System (CWS) or a Non-transient Non-community Water System (NTNCWS) that obtains its water supply primarily fi-om a surface water source and does not have an adequate altemative drinking water source,

  - The Source Water Protection Area for a CWS or a NTNCWS that obtains its water supply from a Class I or Class IIA aquifer and does not have an adequate alternative drinking water source. Where a state has not yet identified the SWPA, the SWPA is replaced with the Wellhead Protection Area.

  - The sole source aquifer recharge area where the sole source aquifer is a karst aquifer in nature.

  For ecological resources:

- *An* area containing a critically imperiled specie or ecological community,
- A multi-species assemblage area,
- A migratory waterbird concentration area,
- *An* area containing an imperiled, threatened or endangered, or depleted marine mammal species that is aquatic, aquatic dependent, or terrestrial with a limited range,
- *An* area containing an imperiled ecological community that is aquatic or aquatic dependent,
- *An* area containing an imperiled species, threatened or endangered species, depleted marine mammal species, or imperiled ecological community that is considered to be the most viable, highest quality, or in the best condition, as identified by an element occurrence ranking of A (excellent quality) or B (good quality).

49 CFR 195.6 provides a comprehensive list of definitions and terminology necessary to fully identify these USAs.

RSPA intends to prepare maps delineating the specific high consequence areas across the United States. The specific geographic locations of the high population areas, other populated areas, commercially navigable waters, and **USAs** will be mapped using the National Pipeline Mapping System. Operators and the public will have access to these maps through the Internet. Operators will then be able to determine locations where a spill from their system(s) could affect a high consequence area.

After they are initially established, high consequence areas will be updated on a periodic basis to incorporate new information and data. For example, as communities grow, the boundaries of high population areas may shift, thus the operator will need to assure protection consistent with the provisions of the rule in these new locations. Similarly, the identification of **USA** locations will be updated reflecting changes in species listings and their locations, and changes in the availability of drinking water resources. RSPA is currently considering the review and update of high consequence area data and maps every five years.

In addition to the high consequence areas, the provisions of the rule will also impact areas of the environment outside of high consequence areas. For example, it is expected that many operators will elect to use internal inspection devices to perform the baseline and periodic integrity assessments. Due to economic and operational considerations, the launchers and receivers used to insert and remove internal inspection devices are typically located at pump stations, which can be many miles apart. Even though a high consequence area may exist for only a short distance along the line, because of the location of pig launchers and receivers, operators will likely inspect the entire pump station-to-pump station segment of a line. Thus, in addition to the information about the condition of the line in a high consequence area, the operator should obtain integrity data about a much larger segment of pipe. Any significant threats identified in these additional areas will also be remediated, thus providing additional protection for the regions adjacent to high consequence areas.

E. Environmental Consequences of Proposed Action and Alternatives

This section describes the expected impact to the environment of the final rule (Section E.1) and the altematives (Section E.2).

E.1 Environmental Impact of the Integrity Management Rule

Section B describes the complete set of requirements for the rule. The essential features of the new requirements are summarized below.

- Operators must pressure test or internally inspect[4] all lines segments where a spill could affect a high consequence area within seven years of the date the rule becomes effective. Assessments conducted within five years prior to the rule effective date may also be accepted as demonstrating adequate integrity of a line segment. Operators must promptly remediate any defects discovered through these assessments that might threaten pipeline integrity.

- Operators must periodically evaluate the integrity of its pipeline using a process that integrates information from other relevant sources with inspection or testing results to fully identify and characterize the potential threats to pipeline integrity. **As** a result of this integrity evaluation, line segments that could affect a high consequence area must also be periodically re-assessed no less than once every 5 years. (Limited exceptions may be permissible subject to **RSPA** review.)

- **As** part of the integrity evaluation, operators must identify and evaluate the need for additional preventive and mitigative actions to protect these areas, including EFRDs and enhanced leak detection capability. The need for additional preventive and mitigative measures would be periodically re-assessed. Performance measures must be used to characterize the effectiveness of the risk control activities and integrity program provisions, and to make any modifications to assure continued protection for high consequence areas.

The impacts of each of these proposed requirements are discussed in this Environmental Assessment. This information is organized as follows:

- A brief summary of internal inspection and pressure testing is provided in Section E.1.1.

- The environmental impacts of these integrity assessment methods are then described in Section E.1.2.

---

[4] The rule also allows for other technologies, but for purposes of this EA, it is assumed that all operators will either pressure test or pig to meet this requirement.

- The environmental impacts of the baseline internal inspection and pressure testing provision of the rule are described in Section **E.1.3.** In this section, the current industry internal inspection and pressure testing practices are compared with what will be required when the rule takes effect.

- The environmental impacts of the periodic assessment requirement are discussed in Section E. **1.4.**

- Finally, the environmental impacts of the other preventive and mitigative measures are considered in Section E. 1.5.

E.1.1 Overview of Internal Inspection and Pressure Testing

Internal in-line inspection, also referred to as "smart pigging," involves the use of **an** electronically instrumented device traveling inside the pipe that measures characteristics of the pipe wall. There are several different technologies used by intemal inspection devices. The most common tools in use are:

- Geometry pigs, which contain electronic sensors that detect geometric or configuration changes in the pipe such as dents, buckles, wrinkles, and ovalities. They are used to identify construction-related or other outside force damage.

- Magnetic flux leakage pigs, which produce a magnetic flux field in the pipe wall and through the measurement of flux leakage identify changes in wall thickness. Flux variations are used to indicate Iocalized pipe wall thinning due to internal or external corrosion, or certain types of gouges. Recently developed tools with a circumferentially oriented magnetic fields have successfully identified axial seam corrosion and some axial cracks.

- Ultrasonic tools, which use sound waves to identify anomalies. There are several designs **of** ultrasonic tools capable of detecting wall thinning and crack or crack-like defects.

The capabilities of intemal inspection devices are improving continuously. New technology and innovation are increasing the accuracy with which defects can be detected, developing high quality inspection capability for smaller diameter pipelines, and developing new or improved techniques to detect a broader range of defects, such as stress corrosion cracking defects and hook cracks in pipe seams. Currently, there is no single intemal inspection tool that can detect all types of pipeline defects or damage. Hence, the selection of a specific tool depends on what type of anomalies or defects the operator is trying to identify. Some operators run geometry or caliper pigs, in combination with magnetic flux leakage tools in order to identify both geometric defects, as well as corrosion metal loss. **A** more complete description of these tools, as well as other in-line inspection technologies, can be found in the literature, including several of the references cited in Section J.

The internal inspection tool output is analyzed to identify the location and severity of pipe wall anomalies or defects. Several industry-accepted methods are used to determine the severity of flaws and the remaining strength of the pipe. These include ASME B31G, ASME B31G Modified, and RSTRENG. In addition, pig vendors, consultants, and operators are developing more sophisticated analytical tools to take advantage of the increasing quality and accuracy of the data available from higher resolution inspection tools. These calculations consider the depth, geometry, and configuration of corroded areas, as well as the proximity to other anomalies to estimate the remaining strength of the pipe at the location of the anomaly. The calculations are used to identify which anomalies are in need of repair (i.e., those areas where the remaining pipe strength is approaching a level where integrity during future operation might be compromised), and to prioritize the excavation and examination of pipe wall defects.

After interpreting and analyzing the results from a pig run, operators typically develop an excavation and repair plan. This plan involves excavating selected anomaly locations to examine the extent of damage and thus confirm the information identified by the pig. After validating the accuracy of the pig runs through these confirmation digs[5], the operator will excavate, examine, and repair, if necessary, those anomalies that have the most potential to threaten pipeline integrity. Operators develop their own criteria for scheduling anomaly repair work. Typically those indications that might pose a near term or immediate threat to pipeline integrity are repaired as soon as possible. Other, less severe indications typicaliy become part of a longer term maintenance plan.

In addition to preventing leaks and accidents, internal inspection provides many operational benefits as well. The inspection results can be used to customize long term maintenance plans, rather than using a "one-size-fits-all" maintenance approach. Internal inspection can also help verify the effectiveness of a pipeline maintenance program. Finally, internal inspection results can be used to fine-tune system operational parameters. For these reasons, as well as the safety benefits, hazardous liquid operators are increasingly relying on internal inspection as a key element of their operation, maintenance, and integrity management programs.

The other method of direct integrity assessment is hydrostatic pressure testing. During a hydrostatic test, a segment of the pipeline is filled with water, pressurized to a predetermined pressure, and held at this test pressure for a predetermined length of time. This testing is performed to eliminate any significant material defects or flaws that might result in failure. The test pressure normally exceeds the maximum allowable operating pressure (typically by 25%). Thus the pipe is subjected to stresses much higher than it would encounter during system operation. After the testing is completed, the only defects remaining in the pipe are those that should not fail at the lower, normal operating pressures. Hydrostatic testing is especially valuable in ensuring that significant longitudinal seam weld flaws and stress corrosion cracks are not present. These types of defects can be difficult to detect with many types of internal inspection devices.

---

[5] Some operators that use modern, high resolution magnetic **flux** tools do not perform confirmation digs.

*E.1.2. Environmental Impacts of Internal Inspection and **Pressure** Testing*

As described in the previous discussion, the purpose of internal inspection and hydrostatic pressure testing is to identify and repair defects or anomalies in the pipe wall that might result in failure if operation were to continue with these defects still in place. Defects such as serious corrosion damage, deformation incurred during construction, and outside force damage to the pipe can be identified by these inspection techniques and repaired. Eliminating or repairing these defects provides greater assurance of pipeline integrity, and reduces the probability that the pipe will fail during subsequent operation. Thus the environmental consequences of a hazardous liquid spill are avoided.

The specific environmental impacts of a release depend on the environmental features in the immediate proximity to the failure location. Impacts also depend on numerous factors including the pipe size and operational parameters, failure size, product released, control center's actions taken in response to the leak, and effectiveness of emergency response efforts. Pipelines traverse a broad spectrum of environments, and the impacts of a release can vary considerably. Experience has shown that pipeline spill consequences can vary from minor, local soil contamination to major, long term damage to environmental resources. Adverse impacts to human health and safety can also occur. Appendix 1 provides a general description of the environmental impacts of hazardous liquid spills.

While internal inspection and pressure testing and repair can not eliminate all pipeline failures, they can reduce the frequency of these events. Thus on a national scale, the cumulative environmental damage from pipeline spills is reduced. Since the provisions of the rule will be implemented on line segments that can affect populated areas, USAs, and commercially navigable waters, it is expected that these resources will benefit by the reduced likelihood of pipeline failure in these areas.

Even though these integrity assessment and repair practices can reduce the frequency of spills to the environment, they are not without some adverse impacts. These are summarized below.

Although hydrostatic testing is an important tool to identify potentially critical defects, the process does have some minor adverse environmental impacts. RSPA considered these impacts in preparing an Environmental Assessment for the rulemaking on "Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines" **(63** FR 59475, Docket # PS-**144).** The key points from this Environmental Assessment are summarized below. More detailed information is available in the Environmental Assessment posted to the docket.

Generally there is some disturbance of the pipeline right-of-way, as short segments of the line may have to be uncovered to conduct the hydrostatic test. However, there is no significant impact on the surrounding land or vegetation as a result of site preparation for the test. There should be very little or no other types of environmental impacts such as noise, air, water, or soil pollution because of the limited amount of equipment (typically a backhoe and pumps) needed on site and their operating characteristics.

The water used for hydrostatic testing mixes with the residue of the hazardous liquid that remains in the pipeline. As a result, the test water becomes a hazardous material which, after the testing is completed, must be disposed of in a manner governed by EPA regulations. (National Pollutant Discharge Elimination System Permits are required.)

Accidental discharges of test water resulting from a line failure or spill during a hydrostatic test will result in a release of water with the accompanying oil or product residue to the environment immediately adjacent to the release point. The low levels of oil residue in the test water should have a minimal impact on the surrounding environment. The test is also closely monitored by operator personnel at the scene who are prepared to respond rapidly and effectively to any leaks or spills during the testing process. Industry experience with numerous hydrostatic tests has shown spills of test water to be infrequent, generally of small volume, and result in no significant or lasting environmental effects.

Similarly, internal inspection has some minor adverse environmental impacts. If the pipeline is not already equipped to conduct an internal in-line inspection, the operator must install launchers and receivers to insert and remove, respectively, the internal inspection device. In some situations, valves or other appurtenances may need to be replaced or modified to allow these devices to pass through the line. Typically launchers and receivers are installed at pump stations, and no additional environmental disturbance is required. In other instances where new launchers and receivers must be installed along the pipeline route, and when mainline valves need to be modified or replaced to accommodate inspection devices, there may be a localized disturbance of the area along the pipeline right-of-way. This disturbance is only for a small localized area on the right-of-way, and does not involve additional vegetation or environmental disturbance beyond the equipment site.

Furthermore, when the operator identifies anomalies that need to be examined and perhaps repaired, there is additional localized disturbance along the right-of-way where the excavation occurs. This localized disturbance is confined to the small region of the line where the anomaly is located, and typically does not involve damage to vegetation or the environment beyond the immediate vicinity of the pipeline corridor. This localized ground disturbance to correct a defect, has far less impact than a leak or failure that might occur if the defect were to remain in the pipe and ultimately fail.

Based on extensive industry experience, RSPA believes that the benefits of hydrostatic testing or in-line internal inspection in reducing the likelihood of a significant oil spill offset the minor adverse impacts of these techniques described above.

E.1.3. Environmental Impacts of Baseline Integrity Assessment Requirements in Final Rule

To understand the environmental impact of the rule, it is necessary to understand the internal inspection and pressure testing programs currently in place, and compare them to the programs that will be required when the rule becomes effective. As discussed at the beginning of this Environmental Assessment, pipeline operators have strong incentives to ensure the integrity of their pipeline assets. As a result, many hazardous liquid pipeline operators have some integrity management activities in place. The use of internal inspection and hydrostatic testing to periodically confirm pipeline integrity are already common liquid pipeline industry practices.

Most hazardous liquid pipeline operators strongly prefer intemal inspection to pressure testing as a means of assuring line integrity. Internal inspection provides a wealth of data about the pipe condition that can support improved operation and maintenance, as well as assure pipe integrity. Hydrostatic testing provides essentially no data on the pipe condition other than, at the time of the test, it is capable of withstanding a given pressure. Operators contacted during the preparation of this Environmental Assessment strongly agreed that given a choice between the two approaches, pressure testing would only be employed where the system design precluded pigging, or where intemal inspection technology is not able to detect certain types of flaws.

In developing an integrity management strategy for a given system, operators consider numerous factors including the pipeline's design parameters and manufacturing process, coating type and condition, age of the system, cathodic protection system performance, observations of pipe condition when the line is exposed for maintenance or other reasons, leak history, operational parameters, and the results of previous hydrostatic tests, intemal inspections, or close interval surveys. Many operators also consider the proximity of the line to population centers and environmentally sensitive resources, as well as their commitments to deliver products to their customers, in developing testing and inspection plans. Because these factors are unique to each pipeline system as well as line segments within a system, each operator's intemal inspection and pressure testing program is customized to address the specific needs of the pipeline systems it operates.

To understand the current integrity assessment activities of operators operating less than 500 miles of pipe, RSPA examined the intemal inspection and pressure testing activities of a number of these operators. This was accomplished by reviewing internal data sources, interacting with selected operators, and discussing operator assessment practices with the OPS Region inspectors who regularly inspect these operators. While there is a wide variation in the integrity management practices of these companies, most of these hazardous liquid pipeline operators appear to have a regular program of intemal inspection or pressure testing. From this limited sample of operators (covering –1500 miles of regulated piping), roughly two/thirds of the line pipe had been intemally inspected or pressure tested in the last five years.[6] For these operators, the baseline and periodic integrity assessment requirements in the new rule would have little

[6] While this data applies to entire operator pipeline systems, the initial assessment requirements in the rule apply only to portions of the line that could affect high consequence areas. Since the mapping of high consequence areas has not been completed at this time, it is difficult to estimate the current rate at which pipelines that could affect these areas are inspected or tested. In considering the environmental protection currently afforded high consequence areas (without the provisions of the rule), it is assumed that the rate at which lines near high consequence areas are intemally inspected or pressure tested is comparable to the overall rate at which operators voluntarily inspect or test their system.

impact since they are already conducting integrity assessments at a frequency comparable to that required by the rule.

However, there are also some operators who will not have performed internal inspection or pressure testing in the previous five years. In the sample of operators examined in this study, these operators' systems comprised less than 10% of the total pipeline mileage. Based on this very limited sample, as well as OPS inspection experience, it is believed that operators who do not have periodic internal inspection or pressure testing programs are believed to be primarily companies with very low pipeline mileage (i.e., tens of miles).

To account for operators that have no integrity assessment activities, as well as for the portions of the other operators' systems where integrity assessments may not have been performed, RSPA assumed that the rule will result in internal inspection or pressure testing of approximately 10% of the line segments that could affect high consequence areas that would not be otherwise assessed. **As** determined by the Regulatory Evaluation[7], this means approximately 540 miles of pipe in high consequence areas will receive additional protection provided by the baseline and periodic integrity assessment requirements of the rule, that would not otherwise have been subjected to integrity assessments.

A simple scoping calculation was performed to estimate the potential benefits of internal inspection in these 540 miles. This calculation assumes that the nationwide incident statistics for all hazardous liquid lines are applicable to high consequence areas. In order to estimate an upper bound on the environmental benefits that might occur from the initial baseline assessment requirement, it is assumed that internal inspection and defect repair will eliminate all failures caused by internal or external corrosion, and prior outside force damage. In fact, although serious corrosion and defects from previously damaged pipe will be detected and removed following the baseline inspection, it is not possible to preclude additional such failures before subsequent integrity assessments occur. It is possible that corrosion processes may still be active, and could result in failure prior to the next inspection. Similarly, third parties could damage the pipe after the repairs to previous outside force damage have been repaired. Thus, assuming these failure modes are eliminated means that this scoping calculation overestimates the environmental benefits.

This calculation estimates that over the initial seven years where operators must complete the baseline inspection in high consequence areas, there is approximately a 20% chance that a failure from corrosion or previously damaged pipe might occur in the 540 miles of pipe that would receive additional protection afforded by this rule. If it is assumed that the internal inspection and repair eliminates these failure mechanisms, the rule would in effect prevent 0.2 incidents in high consequence areas over the period where the baseline integrity assessments are performed. Applying the breakdown of high consequence area mileage used in the Regulatory Evaluation,

[7] "Regulatory Evaluation: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Pipeline Operators with less than 500 miles of Pipelines)," Docket RSPF. 00-7408, September, 2001.

less than half of these incidents would occur in USAs or near commercially navigable waters; the remainder would occur in high or other populated areas.

The net spill volume discharged to the environment for pipe failures caused by corrosion and previously damaged pipe is approximately 320 bbls per incident.[8] Applying this number to the above failure rate indicates that from a statistical perspective, some **64** bbls of net product lost to the environment would be avoided through seven years of the baseline assessment and repair provisions of the rule.

It is likely that not all of the 540 miles used in the above calculation will be intemally inspected. The lack of launchers and receivers, and system design factors may preclude pigging. For those portions of pipeline systems that operators are expected to pressure test instead of conducting an intemal inspection, the impact will be positive, as well. Large defects that seriously compromise the design margin in the pipe will be discovered, and repaired. However, the magnitude of benefits may be less than for intemal inspection. Although pressure testing will identify certain types of defects that intemal inspection may miss (e.g., large, integrity-threatening seam defects), hydrostatic testing does not identify defects that "just survive" the test, but over time may lead to failure during operation (e.g., through cyclic fatigue crack growth associated with normal operational fluctuations). Internal inspection would detect many of these "near critical" defects. Since some portion of the 540 miles addressed in the previous scoping calculation will be pressure tested rather than intemally inspected, the estimated 0.2 incidents avoided over the initial seven year period represents an upper bound on the number of incidents prevented.

The initial integrity assessment required by the rule also provides an important baseline against which future evaluations of line integrity can be compared. Integrating the results of an initial internal inspection with cathodic protection data, close interval survey results, patrolling and one-call information, and other sources supports a more comprehensive evaluation of all factors that influence line integrity. It also provides a valuable benchmark against which future intemal assessments can be compared to understand how conditions in the pipe are changing over time. While these benefits can not be quantified, they are important to providing a comprehensive and long term assurance of system integrity in high consequence areas.

In conclusion, it appears that the requirement to conduct the baseline internal inspections or pressure test all line segments that could affect high consequence areas will result in a very sinal reduction in the number of pipeline failures at these locations, and the impacts that would accompany these failures. In populated areas, preventing such failures would provide additional protection to the public in the vicinity of the pipeline. In the USAs and commercially navigable waters, the environmental damage to these resources following a pipeline failure will be avoided. Because the segments tested or inspected will likely encompass portions of the pipeline beyond the boundaries of the high consequence areas, this additional protection will be provided to a greater length of pipe adjacent to the high consequence areas. However, because the total

---

[8] "Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1986 Through 1996," API Publication 1158, January 1999.

pipeline mileage that is in high consequence areas is expected to be small for operators operating less than 500 miles of pipe, the benefits in terms of number of incidents and amount of oil spilled are small.

Finally, it should be recognized that the initial baseline integrity assessments will not prevent all pipeline failures in high consequence areas. In particular, third party damage from excavators, one of the most significant contributors to pipeline failures, is not effectively addressed through internal inspection or testing. Although serious outside force deformation or metal loss that significantly damages, but does not fail, the pipe will likely be discovered, integrity assessment has no impact on failures where the excavation damage immediately fails the line. The requirement to evaluate high consequence area line segments for additional preventive actions is designed to address third party damage, as well as other **risks** not addressed through inspection and testing (see Section E.1.5).

E.1.4. Environmental Impacts of Periodic Assessment Requirement in the Final Rule

The rule also provides for periodic assessment of line segments that could affect high consequence areas. Reconfirming pipeline integrity in these areas is important **as** conditions change over time. While the initial, baseline assessment establishes the integrity at the time the test is conducted, it is possible that small defects remaining in the pipe may become larger during subsequent operation. Thus over time, the confidence in the integrity of the line is diminished.

For example, although hydrostatic testing will eliminate defects that could result in pipe failure at normal operating pressure, it does not identify smaller cracks that are not large enough to fail under the test pressure. These smaller defects remain in the pipe and can be subject to enlargement when the pipeline is returned to service. For example, corrosion pits may become larger if there is ineffective cathodic protection; or pressure fluctuations during operation may cause existing small cracks to grow due to cyclic fatigue. These defects may grow to a critical size that over time could result in pipe failure. Fortunately, under normal operating conditions with good corrosion control programs, growth rates for defects remaining in the pipe after a pressure test are generally very slow.

The same situation exists for pipeline sections that have been smart pigged. Modern internal inspection tools, especially high resolution tools, will often identify a large number of features in the pipe wall. The vast majority of these are very small indications that will not threaten pipeline integrity. Because these minor features pose negligible **risk,** it is not practical or economical to excavate and repair all of these indications. However, if the corrosion control is ineffective in a localized area, some of these smaller anomalies might continue to grow under continued operation. **An** on-going, integrated evaluation of line integrity, including periodic testing, is desirable to assure the pipeline condition is not significantly degrading, as well as to identify new problems that might occur during operation subsequent to the baseline assessment (e.g., undetected third party damage that dents the pipe, but does not cause immediate failure).

The rule requires operators to re-assess line segments in high consequence areas no less frequently than once every five years with limited exceptions. Furthermore, operators are to consider a number of risk factors to ascertain if more frequent assessments are needed. Operators will be allowed to use longer assessment intervals provided they can justify this decision by a reliable engineering evaluation in conjunction with other monitoring technologies that provid.: a high confidence that the pipe is in good condition.

Most operators with internal inspection and pressure testing programs recognize the need to conduct these assessments periodically to provide continued assurance of integrity. There are several different philosophies on when and how to conduct periodic integrity assessments. Furthermore, operator approaches on periodic assessment are evolving. This is driven in pari by the advances in internal inspection tool technology, and improved analytical methods, that provide better information upon which to base future inspection decisions. Some operators initially established a set integrity assessment periodicity (e.g., every 10 years for all lines). However, as advances in inspection technology provide more information about their system condition, and operators integrate information from other sources, such as cathodic protection readings, exposed pipe reports, and close interval surveys, they are establishing integrity assessment frequencies that are customized for the unique conditions and characteristics of particular line segments. Some operators now have formal integrity management programs that provide a technical basis for making these decisions. The integrity management program requirements in the rule will assure that all operators have such programs, and thus more a more technically defensible basis for making periodic assessment decisions, as well as other risk control activities (see Section E.1.5).

After considering the previously discussed operator assessment practices information, and examining internal inspection and pressure testing programs of several liquid pipeline operators, RSPA believes that the periodic inspection and testing requirements for high consequence areas in the rule will result in a greater frequency of testing or intemal inspection for a larger number of high consequence areas than would have occurred without the provisions of the rule. Informal discussions with operators indicate that the majority of operators with intemal inspection programs have test frequencies of ten years or less - especially in areas that they know would have serious consequences should a failure occur. However, relatively few operators perform integrity assessments on a five year cycle in all areas of high population or environmental sensitivity.

The relative benefits of a five year assessment cycle versus the longer periods used currently by many operators is difficult to estimate. If the operator identifies and repairs all significant anomalies following the baseline assessment, **and** then assures that strong risk controls are in place to prevent corrosion and other integrity threats (as required by the rule), it is likely that integrity assessments every five years will be only marginally more effective in reducing incidents due to corrosion and unrecognized outside force damage than conducting integrity assessments every ten years (a period that is more representative of current operator practice,;).

Some operators covered by the rule have formal, established integrity management programs. These operators may elect to use risk analysis and/or engineering evaluations such as cycle fatigue crack growth models to justify a periodic assessment interval longer than five years or segments that the baseline assessment shows to be in good condition, and where strong risk controls are in place to minimize the occurrence of a leak or spill. In these cases, the impact of the rule on an operator's periodic integrity assessment program would likely be small.

Periodic testing and inspection will assure that the higher level of confidence in the line integrity that was achieved from the initial baseline test is maintained. Thus it is expected that the impact on the likelihood of failures from corrosion and previously damaged pipe would be similar to, or somewhat less[9] than, the estimates provided in the previous section. Hence, the periodic assessment requirements of the rule will have a small positive benefit in terms of environmental protection when compared to existing operator practices for periodic integrity assessments.

E.1.5. Environmental Impacts of Other Preventive and Mitigative Actions

The final major element of the rule is the requirement that operators periodically review the existing preventive and mitigative measures in place for each high consequence area, and consider what additional activities or enhancements to these measures might be warranted to enhance protection. In conducting this evaluation, operators will be expected to examine the entire range of threats to pipeline integrity in high consequence areas, integrating information from all applicable and available sources, including applicable experience along the entire pipeline. RSPA expects operators to consider (at a minimum) information such as:

- Pipeline design features, including wall thickness, type of seam and pipeline age;
- Construction practices and information;
- Operating history, including leaks and incidents;
- Maintenance and surveillance records, including cathodic protection system performance, and patrolling;
- Previous inspection/testing results (internal inspection, pressure testing, or close interval surveys) and time since last inspection;
- Exposed pipe reports, including coating condition;
- Condition of above-ground equipment;

---

[9] One the baseline assessment has been performed, significant construction related defects, and outside force and corrosion defects that may have existed for many years will be removed. Assuming a sound program of risk controls is in place, subsequent inspections will generally discover fewer significant anomalies.

- Susceptibility to natural hazards such as ground movement;
- Damage prevention program effectiveness;
- System operating parameters and SCADA system performance;
- Commodity transported;
- Proximity to and specific features of the high consequence area (e.g., population density distribution, type of environmental resource);
- Mitigation feature effectiveness in limiting the volume of product released; and
- Spill response plan effectiveness and availability of equipment.

The integrated evaluation of this information should identify location-specific conditions that might pose significant risks in high consequence areas, and support improved decisions to protect these areas. Operators will be expected to identify the major risks in **high** consequence areas, prioritize these risks, and consider what actions might be warranted to address the most important risks. As part of this evaluation, RSPA expects operators to critically evaluate the effectiveness of their existing prevention and mitigation measures as part of this process. The rule also requires that operators explicitly consider whether EFRDs or enhancements in leak detection capability are needed to protect high consequence areas.

Operators will also be required to evaluate the effectiveness of their integrity management program through performance measurement. This periodic evaluation will assure that the program is continually effective in managing and reducing risk in high consequence areas. OPS review of inspection results, integrity analysis, and consideration of additional preventive and mitigative actions will provide added assurance that a thorough evaluation has been conducted and operators have implemented an appropriately strong program to protect high consequence areas.

As a result of this evaluation, some operators may elect to implement additional risk control activities to enhance protection for high consequence areas. For example, depending on the site-specific situation, operators may decide to:

- Implement some of the damage prevention best practices identified in the recent Common Ground Report in an area where population expansion and increased construction is expected;
- Implement new technologies capable of providing full time monitoring of cathodic protection levels at locations where corrosion is a high concern;

- Install an additional block valve that would minimize the amount of product released in the event of a spill;

- Install remote operators on block valves so that the line could be isolated more rapidly after a significant failure occurs;

- Install check valves to prevent flow reversal in the event of a break, thus minimizing the amount of product released to the environment;

- Upgrade **SCADA** and leak detection system capabilities;

- Pre-stage emergency response equipment so that in the event of a spill, effective response actions can be mobilized more quickly; or

- Conduct drills with local emergency responders that are focused on protection of a specific high consequence area.

Additional preventive or mitigative actions such as these will evolve fiom the operator's analysis of the risks in specific high consequence areas. **As** such, they will be operator and site specific.

The existing pipeline safety regulations already protect high consequence areas. The new integrity management rule provides additional protection because of the sensitivity of these areas to pipeline failures. Some operators recognize the importance of preventing accidents in these areas, and have programs and activities that extend beyond the regulations to provide additional protection. For this reason, it is expected that some operators may determine that a number of their high consequence areas already have adequate protection, and that further actions would not produce the demonstrable benefits.

Without knowing where the high consequence areas are located, and without operators having performed the risk analysis noted above, it is not possible to make definitive conclusions on the impact of this provision of the rule. Based on discussions with selected operators, **RSPA** believes that this provision may result in additional risk control measures for a small number of high consequence areas, and thus improved environmental protection at these locations. This is most likely to occur in a high consequence area that the operator had not previously identified. While these additional preventive and mitigative measures will provide enhanced protection for the specific locations, in aggregate they are not likely to be significant on a nationwide scale.

E.1.6 Summary of Environmental Impacts for Final Rule

As a whole, the combined impacts of the initial baseline integrity assessment (pressure testing or internal inspection), subsequent periodic assessments, the integrated and continuous evaluation of line integrity, additional preventive and mitigative measures that may be implemented in high consequence areas, and performance measurement of the integrity management program wil result in positive environmental impacts. The number of incidents and the environmental damage from failures in high consequence areas should be reduced slightly. From a national perspective, the impact is not expected to be significant for the pipeline operators who operatc:: less than 500 miles of pipeline for the following reasons:

- Many operators covered by the rule already have intemal inspection and pressure testi ıg programs that cover most, if not all, of their pipeline systems. These operators typically place a high priority on the pipeline's proximity to populated areas, commercially navigable waterways, and environmental resources when making decisions about where and when to inspect and test pipelines. **As** a result, some **high** consequence areas have already been recently assessed, and a large fraction of remaining locations would probably have been assessed in the next several years without the provisions of the rule. The most tangible impact of the rule will be to ensure assessments are performed for those line segments that could affect a high consequence areas that are not currently being internally inspected or pressure tested, and ensuring that integrity is maintained through an integrity management program that requires periodic assessments in these locations. Because pipeline failure rates are low, and because the total pipeline mileage operated by operators with less than 500 miles of pipe that could affect high consequence areas is small (estimated to be **-5440** miles), the rule has only a small effect on the likelihood of pipeline failure in these locations. Using recent hazardous liquid pipeline failure data, the number of failures avoided by the baseline assessment provision of the rule is estimated to be less than one, nationwide.

- The rule will result in more frequent integrity assessments of line segments that could affect high consequence areas than most operators are currently conducting (due to the five year interval for periodic assessment). However, if the operator identifies and repairs significant problems discovered during the baseline inspection, and has in place solid risk controls **to** prevent corrosion and other threats (as required by the rule), the benefits of testing every five years versus the longer intervals operators more typically employ are not expected to be significant.

- The rule requires operators to conduct an integrated assessment of all potential threat:; to pipeline integrity, and to consider additional preventive or mitigative risk control measures to provide enhanced protection. If there is a vulnerability to a particular failure cause - like third party damage - these evaluations should identify additional risk controls to address these threats. Some of liquid operators covered by the rule already perform integrity evaluations or formal risk assessments that consider the environmental sensitivity and impacts on population. These evaluations have already led to additional risk controls beyond existing requirements to improve protection for these locations. Without identifying the specific high consequence area locations, the specific risks present at these locations, and the existing operator risk controls (including those that surpass the current minimum regulatory requirements), it is difficult to determine the impact of this requirement for additional preventive and mitigative activities. However, for many companies, it is expected that additional risk controls will be limited and customized to site-specific conditions that the operator may not have previously recognized. For many high consequence areas, it is probable that operators will determine the existing preventive and mitigative activities provide adequate protection, and that the small additional risk reduction benefits of additional activities does not justify their implementation.

- Finally, an important, although less tangible, benefit of the rule will be to establish requirements for operator integrity management programs that assure a more comprehensive and integrated evaluation of pipeline system integrity in high consequence areas. In effect, this will codify and bring an appropriate level of uniformity to the integrity management programs some operators are currently implementing. It will also require operators who have limited, or no, integrity management programs to raise their level of performance. This rule will impose the same integrity management requirements on operators operating less than *500* miles of pipeline as those recently issued for operators operating *500 or* more miles of pipe *(65* FR **75378).** Thus, the rule is expected to provide a more consistent, and overall, a higher level of protection for high consequence areas across the industry. While this impact is certainly positive, it is not possible to quantify in terms of improved safety and environmental protection.

E.2. <u>Environmental Impacts of the Alternatives</u>

E.2.1 ***Take*** *No* ***Action.***

Under the "No action" alternative, RSPA would not issue any rule requiring assessment or integrity management for hazardous liquid pipelines in high consequence areas. It is expected that existing pipeline operator integrity management activities (both those required by Part 195, and those the operators perform voluntarily), as well as OPS oversight, would continue.

After RSPA identifies unusually sensitive areas (as described in *65* FR **80530,** December 21, 2000), and depicts them on maps with commercially navigable waters **and** populated areas, it is expected that some operators may voluntarily examine portions of their pipelines that are in or near these areas, **and** review their existing preventive and mitigative risk control measures for these locations. Some operators may voluntarily perform integrity assessments or implement additional risk control activities. However, as noted previously, most operators are aware of the environmentally sensitive areas and populated regions along their pipeline systems, and have taken what they believe to be appropriate actions to prevent and respond to spills at these locations. Thus it is expected that most additional, voluntary actions taken to protect high consequence areas would probably be limited to a small number of specific locations - primarily where mapping identifies a high consequence area that the operator had previously not recognized.

In summary, the "no action'' alternative would have essentially no impact on environment. The benefits from increased integrity testing and inspection, more formal and integrated approaches to integrity management, and OPS oversight of operator integrity management plans for high consequence areas that are key elements of the rule would not be realized under this altemativ:.

*E.2.2 Mandatory Integrity Assessment in all **High** Consequence Areas Every Ten Years*

This altemative requires that the initial baseline assessment of pipeline segments that could affect high consequence areas be completed in a longer period than the rule (i.e., ten years instead of seven years). This altemative also provides a longer maximum interval between subsequent integrity assessments - up to ten years between assessments versus the five year limit in the final rule.

After conducting an integrity assessment, an operator has a high degree of confidence that the pipeline segment has no significant defects which might result in near-term failure. However, during subsequent operation after the integrity assessment, a number of time-dependent (e.g., corrosion, cyclic fatigue) and other factors (e.g., outside force damage) may act on the pipeline. These factors reduce the level of confidence in the pipe's integrity, as the time since the last integrity assessment increases. By providing operators ten years instead of seven to conduct the baseline assessments and allowing an extra five years between subsequent assessments, the likelihood that a failure will occur in these locations is increased. This increase in risk would be small (statistically, much less than one incident per year) - primarily because the total mileage of pipe affected by this rule is not large and pipeline failure rates are already relatively low, Nevertheless, RSPA believes that sensitive environmental resources and populated areas near pipeline facilities operated by operators with less than 500 miles of pipeline should be afforded the same protection as those resources and populated areas near pipelines operated by operators with 500 or more miles of line. Since there is no compelling technical or practical justification for different requirements for this set of operators, the rule contains the same integrity assess nent requirements as the final rule recently established for operators with 500 or more miles of pipe (65 FR **75378).**

F. Environmental Justice Considerations

In accordance with Executive Order 12898 (Federal Actions to Address Environmental Justice in Minority and Low-Income Populations), RSPA has considered the effects on minority and low-income populations of the provisions of this rule. The testing and other integrity management activities of this rule will enhance safety and environmental protection for high consequence areas. High consequence areas include regions near pipeline facilities that are populated, or have a commercially navigable waterway or an Unusually Sensitive Area. The **USA** definition identifies drinking water and ecological resources that may be unusually sensitive to damage from an oil spill. The rule applies to all high consequence areas nation-wide, and does not specifically target any communities.

Additional protection afforded populated areas will benefit all citizens in proximity to hazardous liquid pipelines, regardless of their economic or minority status. Any additional protection of ecological resources may provide some indirect benefits to communities in proximity to such resources, in addition to the national and global benefits. However, these benefits will be realized regardless of a community's economic or minority status. Therefore, the new integrity management rule for operators who operate 500 or less miles of pipeline does not have disproportionately high or adverse health or environmental effects on any minority or low-income populations near oil pipeline facilities.

G. Information Made Available to States, Local Governments, and Individuals

RSPA has made the following documents publicly available, and incorporates them by reference into this environmental assessment:

"Regulatory Evaluation: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Pipeline Operators with less than 500 miles of Pipelines)," Docket RSPA 00-7408, September, 2001.

"Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators with less than 500 miles of Pipelines)," 66 FR 15821, March 21, 2001

"Pipeline Safety: Areas Unusually Sensitive to Environmental Damage," 65 FR 80530, December 21, 2000.

"Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators with 500 or More Miles of Pipeline)," 65 FR 75378, December 1, 2000.

"Environmental Assessment: Final Rule, Pipeline Integrity Management in High Consequence Areas for Hazardous Liquid Pipeline Owners or Operators Operating 500 or More Miles of Pipeline," Docket RSPA 99-6355, November 2000.

"Pipeline Safety: Pipeline Integrity Management in High Consequence Areas," Notice of Proposed Rulemaking, 65 FR 21695, April 24, 2000.

"Environmental Assessment: Proposed Rulemaking Integrity Management in High Consequence Areas for Hazardous Liquid Pipeline Operators Operating 500 or More Miles of Pipeline," Docket RSPA 99-6355, April 2000.

"Draft Regulatory Evaluation: Pipeline Integrity Management in High Consequence Areas," Docket RSPA 99-6355, March 2000.

"Pipeline Safety: Areas Unusually Sensitive to Environmental Damage," Notice of Proposed Rulemaking, 64 FR 73464, December 30, 1999.

"Pipeline Safety: Enhanced Safety and Environmental Protection for Gas Transmission and Hazardous Liquid Pipelines in High-Consequence Areas," Notice Extending Comment Period and Establishing Electronic Public Discussion Forum, 64 FR 71713, December 22, 1999.

"Environmental Assessment: Proposed Definition of Areas Unusually Sensitive to Environmental Damage (USAs)," Docket RSPA 99-5455, December 1999.

"Pipeline Safety: Enhanced Safety and Environmental Protection for Gas Transmission and Hazardous Liquid Pipelines in High Consequence Areas," 64 FR 56725, October 21, 1999.

"Areas Unusually Sensitive to Environmental Damage," Notice of Initiating Pilot Testing, 64 FR 38173, July 15, 1999.

"Emergency Flow Restricting Devices/Leak Detection Systems," Advance Notice of Proposed Rulemaking, 59 FR 2802, January 19, 1994.

"Environmental Assessment: Hydrostatic Testing of Certain Hazardous Liquid and Carbon Dioxide Pipelines," Docket PS-**144,** June 9, 1993.

"Emergency Flow Restricting Devices Study," Docket PS-133, 1991.

H. List of Agencies and Persons Consulted

During the process of developing the integrity management rule, **RSPA** interacted and consulted with numerous organizations. These participants included:

- American Petroleum Institute
- Association of Oil Pipe Lines
- Independent Liquid Terminals Association
- National Association of Pipeline Safety Representatives
- National Association of Regulatory Utility Commissioners
- Environmental Defense Fund
- National League of Cities
- LEPC Information Exchange
- Safe Bellingham
- **US** Public Interest Research Group
- Pipeline Reform Coalition
- City of Fredericksburg, Virginia
- International Union of Operating Engineers

I. Conclusion

Hazardous liquid pipeline failures that significantly impact the environment occur infrequently. Nonetheless, RSPA believes additional assurance of system integrity is important for high consequence areas, and that the rule will improve protection in these locations, as well ensure consistency in maintaining this protection. This Environmental Assessment has considered the impacts of the provisions in the rule, and determined that a reduction in the **risk** associated with pipelines operating in high consequence areas should be expected. However, because many of the liquid pipeline operators that will be covered by this rule are already performing some of the baseline integrity assessment and other activities required by this new rule, and because the total pipeline mileage impacted by the rule is limited, the impact is expected to be small. Therefore, RSPA has concluded that the modifications to 49 CFR 195 to validate pipeline integrity in high consequence areas for operators operating less than 500 miles **of** pipe will not have a significant environmental impact.

J. References

"In-Line Nondestructive Inspection of Pipelines," NACE International, Publication 35100, December, 2000.

"Pipeline Safety Hearing: Inspection and Integrity Verification," National Transportation Safety Board, November 15-16,2000.

"Analysis of DOT Reportable Incidents for Hazardous Liquid Pipelines, 1986 Through 1996," API Publication 1158, January 1999.

"Assurance of Hazardous Liquid Pipeline System Integrity," API Recommended Practice 1129, August 1996.

"Common Ground: Study of One-Call Systems and Damage Prevention Best Practices,'' US DOT, August 1999.

"Pressure Testing of Liquid Petroleum Pipelines," API Recommended Practice 1110, March, 1997.

"Environmental Assessment of the Proposed Longhorn Pipeline System," US EPA and US DOT, October 29, 1999.

''Instrumented Intemal Inspection Devices," US DOT, November 1992.

"Pipeline Risk Management Manual," W. Kent Muhlbauer, Gulf Publishing Company, 1996

"Regional Assessment of Aquifer Vulnerability and Sensitivity in the Conterminous United States," Pettyjohn et al., EPA/600/2-91/043, August, 1991.

Appendix 1

Environmental Impacts of Oil Spills

The hazardous liquid pipeline industry operates more than 157,000 miles of pipeline and related facilities that transport products ranging from crude oil to refined products (e.g., diesel fuel and gasoline) to highly volatile liquids (e.g., ethylene and carbon dioxide). These pipelines traverse each of the fifty states, passing through all types of environments from coastal shores and wetlands, to prairies and deserts. The affected environment covered by this Environmental Assessment consists primarily of high consequence areas (as defined in Section D). Because these locations have yet to be mapped, they could occur in any area in the United States that is in proximity to a hazardous liquid pipeline regulated under 49 CFR Part 195, "Transportation of Hazardous Liquids By Pipeline." For this reason, this appendix provides a general discussion of the environmental impacts of oil and petroleum product spills on different environmental resources.

1.1 Characteristics of Oil

"Oil" is a generic term used to describe a closely related series of complex hydrocarbon compounds that can range from gasoline to heavy solids. The various mixtures that constitute "crude oil" can vary greatly in their chemical composition. Because they consist of mixtures of thousands of hydrocarbon compounds, their physical properties such as color, specific gravity, and viscosity also vary widely.

Oils are classified using specific gravity or the American Petroleum Institute gravity scale and relative mobility. Crude oil is generally broken down into four groups:

- Tar Sands - immobile oil.
- Heavy Oils - No. *6* fuel oil ***(MI*** gravity <20°).
- Medium Oils - most crude oils (API gravities between 20" and 25").
- Light Oils - jet fuel, gasoline, diesel, No. 2 fuel oil (API gravities >25°).

The different types of oils behave differently during a spill. Due to their high volatility, light weight oils generally do not persist in the environment. The very light weight oils, gasoline and jet fuel, are the most toxic but they evaporate quickly, usually within one to two days after a spill. Diesel, which is slightly heavier, tends to leave a residue of up to one-third of the amount spilled for several days.

Medium-weight oils pose the greatest environmental risks to organisms because the compounds are more persistent, are biologically available, and have high toxicities. Evaporative losses ar: lower, with about 70 to 80% of the amount spilled remaining after twenty-four hours.

The heavy weight oils are the most persistent oils. Degradation rates are very slow and they persist in sediments as tar balls or asphalt pavements. Animals generally have to be exposed via a sediment pathway or through the food chain.

General characteristics of the different types of oils can be summarized as follows:

Type	Volatility	Solubility	Toxicity	Bioavailability
Light Oils	Rapid, significant evaporation. Very light oils have complete evaporation in 1-2 days. Light oils have up to ~2/3 evaporative losses in 1-2 days.	High water solubility.	High acute toxicity fiom monoaromatic hydrocarbons (benzene, toluene, xylene).	Little potential for bioaccumulation.
Medium Oils	Evaporation rates in days, some residue does not evaporate at ambient temperatures.	Low water solubility.	Moderate acute and chronic toxicities fiom diaromatic hydrocarbons (naphthalenes).	Moderate potential for bioaccumulation.
Heavy Oils	Almost no loss by evaporation.	Almost no water solubility.	Potential for chronic toxicity fiom polynuclear aromatic hydrocarbons (phenanthrene, anthracene); little acute toxicity **risk** except that due to smothering.	Potential for bioaccumulation via sorption onto sediments, otherwise not highly bioavailable.

Within each of these types of oil, the smaller, or lighter weight, compounds are the more toxic

1.2 Overview of Environmental Consequences

The following discussion summarizes the potential environmental impacts of oil spills. This section is not intended to provide a comprehensive description of all possible environmental impacts resulting fiom oil spills; rather, the objective is to provide an overview of the more important environmental consequences.

1.2.1 Surface Waters

Spilled oil can pose serious threats to freshwater and ocean environments. The severity of impact of **an** oil spill, as well as the ability to recover from the spill, will depend on a variety of factors including the location and quantity of oil released, the characteristics of the spilled oil, the characteristics of the area affected, and local weather conditions.

Weathering

Weathering is a series of chemical, physical and biological changes that occur when the crude oil and petroleum products interact with the water environment. Some of the more important natural weathering actions are described below.

- Spreading/dispersion occurs when wind and wave action spreads the oil over the surf ice of the water forming a thin film or slick. The speed at which this occurs depends on the viscosity of the oil and prevailing conditions such as temperature, water currents, tidal streams and wind speeds. Slicks generally spread quickly to cover extensive areas of the water surface. After a few hours the slick will begin to break up and form narrow bands, or windrows, parallel to the wind direction. Dispersion occurs when the slick is further broken down into droplets, which are distributed throughout the upper layers of the water column.

- Evaporation occurs when the lighter oils volatilize and disperse into the atmosphere leaving the heavier components of the oil behind in the water. Evaporation is the single most important weathering process in the first several days of a spill. The amount of evaporation and the speed at which it occurs depend upon the volatility of the oil. Environmental factors affecting evaporation include the exposed area of the slick, wind speed, water surface roughness, air temperature, and formation of emulsions. Light, refined products like gasoline may evaporate completely within a very short time. In general, evaporation will remove 20 to 60% of a crude oil spill. Volatilization of th.:

low-boiling aromatics can have an impact on marine life as these compounds are highly toxic.

- Oxidation occurs when oxygen combines with oil. Oxidation of the oil hydrocarbons will form fatty acids and other water-soluble compounds promoting additional transport of organic materials from the oil film into the water. The process is aided by sunlight but is very slow even in ideal conditions. It occurs mostly around the edges of the spill. Thick layers of high viscosity oil or emulsions may only partially oxidize to form dense, sticky, black spheres (tar balls) which may linger in the environment.

- Biodegradation occurs when microorganisms in the water feed on the oil hydrocarbons. This process can partially or completely degrade oil to water soluble compounds and eventually to carbon dioxide and water. The main factors affecting biodegradation are the levels of nutrients in the water, the temperature, and the level of oxygen present. Since no oxygen is available within the oil itself, the process can only take place at the oil-water interface. Biodegradation tends to work best in warm water environments. To sustain biodegradation, nutrients such as nitrogen and phosphorus are sometimes added to the water to encourage the bacteria to grow and reproduce.

- Emulsification occurs when wave action causes the oil and water to combine, with one ending up as small droplets suspended in the other. The formation of emulsions will cause the volume of the spill to increase between three and four times. Two types of emulsions may exist: water-in-oil and oil-in-water. Water-in-oil emulsions, or "chocolate mousse,'' are formed when strong wave action causes water to become trapped inside viscous oil. Mousse emulsions are very viscous and more persistent than the original oil. Emulsions cause oil to sink and disappear from the surface of the water while accumulating in the bottom sediments and lingering in the environment for months or even years.

Even large spills of refined petroleum products, such as gasoline, in water evaporate quickly and may cause only short-term environmental effects. In contrast, crude oils, heavy fuel oils, and water-in-oil mixtures may cause widespread and long-lasting physical contamination of aquatic habitats and shorelines.

<u>Location</u>

Oil spills in open bodies of water can be harmful to many forms of aquatic life because they prevent sufficient amounts of sunlight from penetrating and also reduce the level of dissolved oxygen in the water. Crude oil can render feathers and gills ineffective, so that birds and fish may die from direct contact with the oil itself. However, marine organisms have the ability to swim away from a spill by going deeper into the water or further out to sea, thus reducing the likelihood that they will be harmed.

Unlike ocean spills that are dispersed by wind and wave action, oil spilled near the shoreline or in rivers, lakes, or other calmer bodies of water typically concentrates and mixes with near-shore waters or collects along shorelines. Oil deposited in near-shore sediments persists longer than in ocean sediments, and is particularly persistent in low-energy, wetland habitats. High-energy, rocky shores tend to clean themselves with a matter of months, whereas soft-sediment lagoons, marshes, and mangrove swamps act as long-term petroleum sinks. On cobble and sandy beaches, oil can sink deeply into the sediments and remain longer than on bare rocks. Sediment grain size and compaction determine the rate of oil penetration. In muddy sediments, only the upper few inches are penetrated. However, because there is generally little weathering in these environments, stranded oil can persist for many years. Heavy oiling of the shore can cause immediate, widespread death of plants and animals. The long-term effects are more subtle.

The United States contains extensive developments of salt, brackish, and freshwater marsh systems, many of which serve as the primary food source for both the coastal and near shore ecosystems of the region. Marshes serve as nursery habitats and generally have a high diversity and density of animal and plant species. The impact of near shore oil spills on these bordering wetlands can be significant.

When floating oil is pushed into the marsh by tidal or wave action, it adheres readily to the vegetation. The band of coating can vary widely depending on wave height but large, persistent slicks tend to coat the entire plant stem. If the marsh vegetation is thick, contamination by heavy oils can be restricted to the outer fringe of the marsh. Light oils can penetrate much deeper, generally to the limit of the tidal or wave influence. Fresh oils tend to slide down the stems in warmer weather and pool on the sediments at the base of the plant. Weathered oils are more likely to stay on the vegetation. Medium-to-heavy oils pool onto the sediment surface, while the lighter oils can penetrate the top few inches of sediment and deeply into burrows. In extreme cases like the West Falmouth spill where high wind and waves mixed diesel deeply into the estuary sediments, studies have documented long-term (i.e., more than ten years) persistence of oil in both sediments and the food chain.

In the past, the greatest impact of the oil spill on the marsh frequently resulted from the cleanup efforts. Root systems were destroyed by trampling. Surface sediments were removed leaving little to support new growth. The remaining oil mixed into deeper sediments, slowing the natural weathering and removal process. Mobilized sediments smothered surrounding vegetation. Responders are now more sensitive to the possibility of causing harm; cleanup tends to be limited to the passive collection of the oil onto sorbents.

1.2.2 Groundwater

Spilled oil may affect nearby streams or ponds or it may be absorbed by the soil and reach the water table. Since ground water levels in the U.S. are typically between ten and twenty meter,; from the land surface, and can be a little as three meters or less, the potential for groundwater contamination from a spill can be significant.

The severity, duration, nature and extent of the impact on groundwater resources depend on a large number of interdependent factors including:

- Type and quantity of oil released,
- Rate of release,
- Land slope,
- Soil thickness and grain size,
- Underlying geology,
- Soil temperature,
- Precipitation,
- Distance to aquifer,
- Stability of water table, and
- Aquifer permeability and transmissivity.

A release that contaminates groundwater would most likely be either a slow, undetected leak that occurs in an area where the leaking oil would not be easily observed at ground surface, or a pipeline rupture. The depth to which the oil would penetrate the subsurface in the event of a slow leak is most dependent on the volume discharged. The volume that actually reaches groundwater decreases with increasing vertical and horizontal distance to the aquifer. Oils released onto fractured bedrock or highly permeable sand and gravel migrate quickly. Less permeable materials like silt, clay or unfractured bedrock inhibit downward migration. If the pipeline is buried below the water table and a leak or rupture occurs, there is a high probability the groundwater will be affected regardless of the released volume.

Once an oil spill has occurred, the oil flows through the soil's unsaturated zone. Some residual oil will be absorbed by the soil particles. When the remaining oil reaches the water table, it forms a film which floats on the surface of the aquifer and is moved along with the general low of the water. Some oil will continue to be absorbed by the soil particles lying just above the water table. The hydrocarbon plume will move with the groundwater gradient at a slightly slower speed than the water; concentrations will be greatest near the top of the aquifer.

As the oil starts to mix with the water, a selective and specific redistribution of molecular compounds between soluble and suspended fractions occurs, initially through the physical dissolution of the water-soluble compounds. These two fractions, soluble and insoluble, will have different proportions and concentrations of organic compounds. The soluble fraction will be predominately aromatic, substituted, and low aliphatic hydrocarbons, including fatty, carboxylic and naphthenic acids, phenols, and cresols. Higher concentrations of polycyclic and high-molecular-weight aliphatic hydrocarbons will be found in the suspended fraction. After two to seven days, additional water-soluble compounds will be formed as a result of chemical and biological oxidation. These oxidized hydrocarbons will contain substantial quantities of fatty and carboxylic acids and are considerably more toxic than the original unoxidized hydrocarbons.

A large volume of groundwater downstream from the spill can become contaminated. The most serious impacts from such contamination include degradation of groundwater quality and impairment of drinking water supplies. Crude oil may have significant impacts to long-term water quality in ground water because the higher viscosity, sorbability, and specific gravity make crude oil more likely to sink deeper into the ground water column, to resist natural dilution and transport through flushing, and to be less likely to volatilize. Gasoline may also have serious impacts to drinking water quality for both ground water and surface water. The transport characteristics of benzene and methyl tertiary-butyl ether (MtBE) make it more likely to reach a drinking water source in the event of a release. Some studies indicate that, depending on soil conditions, gasoline spills can reach deep ground water tables in a matter of hours or days.

The presence of specific additives in refined oil products can result in additional environmental concerns. For example, MtBE is a volatile, organic chemical which is added to gasoline as an octane enhancer and oxidizer. MtBE is used in more than 85% of reformulated gasoline, which accounted for approximately 30% of the gasoline used nationwide in 1997. Studies have identified significant air quality and public health benefits from the use of such reformulated gasoline. However, the potential environmental impact, and human health risk, from MtBE is currently being debated. MtBE is hydrophilic, does not readily bind to soil particles, and resists natural degradation. These qualities allow it to travel quickly and easily into underground water supplies. There have been a limited number of instances of significant contamination of drinking water sources due to leaks from petroleum storage tanks and pipelines. Between 5 and 10% of drinking water supplies in high oxygenate fuel use areas show at least detectable amounts of MtBE, with approximately 1% showing levels above 20 ppb.

1.2.3 Soils

While the very light oils seem to cause the least damage on water, the opposite seems to be true on land. Light weight oils tend to penetrate the top soil quickly, thus placing groundwater at risk. The higher viscosities of the heavier oils make soil penetration difficult, thus slowing contamination.

The significance, magnitude, and duration of soil impacts from a spill depend on a number of factors including:

- Type and quantity of oil released;
- Depth of product penetration;
- Soil properties and chemistry, including water content, porosity, texture and organic carbon content;
- Terrain features; and
- Soil and air temperatures.

Land oil spills more frequently involve refined petroleum products like gasoline or diesel fuel, than marine spills, which generally involve crude oil. Differences in chemical composition and physical characteristics can lead to differing environmental 'impacts depending on the specific oil involved in the spill. For example:

- In the absence of an ignition, a large crude oil release would result in more severe long-term impacts to land use because of the slower movement rates and lower volatilization.

- If ignition occurs, gasoline will impact a larger area and potentially cause more damage to land use. Gasoline is more likely to ignite than crude oil, and because of the rapid heat release and the wider spread from a comparable volume released, a gasoline fire would be expected to result in greater damage than a fire involving crude oil.

Environmental effects from a spill on land tend to be confined to the immediate vicinity of the spill. Spreading is generally limited to a migration to the lowest point in the area. Generally, losses due to evaporation will be limited and formation of emulsions is rare. Little physical change occurs in the oil unless it is left on the ground for an extended period. However, the spill may change the physical, chemical, and microbial properties of the soil thus decreasing vegetative fertility and productivity.

Spills on unsaturated soil may produce boggy, barren areas. As the oil penetrates the soil, it coats the soil particles thus reducing the soil's infiltration capacity and aeration. The pH may be altered, creating alkaline or acidic soil conditions. There can be an immediate loss of vegetation due to smothering or toxic effects. This will lead to increased erosion and offsite sedimentation. Plant growth and revegetation of the area may be inhibited because of insufficient plant-available water and poor root aeration. This decrease in the area's productivity may last years depending on the topography, environmental conditions, and remediation practices employed. Long-term impacts depend on the removal of contaminated soils and the recovery rate of the affected ecosystems.

1.2.4 Air Quality

Air quality can be impacted through evaporation from oil spills. Volatile organic compounds (VOCs), possibly including hazardous air pollutants (HAPs), will be released under these conditions. VOCs are indirectly regulated by the **EPA** through the ozone standards included in the National Ambient Air Quality Standards. HAPs of concern may include hexane, benzene., toluene, 2,2,4-trimethylpentene, xylene, and ethylbenzene.

The evaporation of these volatile chemicals from oil spills can result in significant, localized, and short term air pollution in the immediate vicinity of the spill. Most of the hydrocarbons that evaporate quickly are the low molecular weight aromatics such as benzene, toluene, and xylene. These hydrocarbons are among the most toxic components of crude oil and refined products. Because of the localized presence of these volatile constituents, they are of concern mainly for workers in the immediate vicinity of the spill. With gasoline spills, vapor concentrations above 1,000 ppm can cause headaches, dizziness, weakness and loss of coordination; higher concentrations, above 5,000 ppm may cause loss of consciousness or coma. Depending on the specifics of the spill, including amount of product spilled, wind speed and localized soil permeability, some volatile chemicals may reach toxic concentrations above the immediately dangerous to life or health (IDLH) limits.

In the presence of sunlight, the released hydrocarbons will react with oxygen in the air, through a process called photo-oxidation, and form carbon dioxide, various sulfur-oxygen compounds, and acids. If nitrogen oxides are present, some hydrocarbons may form ozone. Ozone formation increases almost proportionally to hydrocarbon concentration. However, the various types of hydrocarbons differ significantly in their ability to react with nitrogen oxides. If the oil is burned, either during a fire associated with a spill or as part of the cleanup process, the by-products of incomplete combustion can contribute to air pollution and smog.

1.2.5 Biological Impacts

The consequences of a spill on a specific biological system are dependent upon a number of different factors including the type and amount of oil spilled, the geology of the area, local meteorological conditions, the season, and the type and sensitivity of the biological communities likely to be affected. The chemical properties of the oil will strongly influence the impacts that can be expected in a particular habitat since both toxicity and longevity are dependent on the type of oil spilled. For example, experiments with phytoplankton have found that light oils have an inhibiting effect on growth while the heavier oils have little effect; these differences appear to the linked to the percentage of water soluble compounds in the original hydrocarbon mix. The physical and meteorological conditions at the site affect where the oil will go and how quickly it will weather. The presence of migratory birds or mammals and the aggregation of individuals, for breeding or spawning are examples of seasonal behaviors that can influence the vulnerability of a biological community to an oil spill.

Oil can harm fish, birds and mammals in several ways, including:

- *Physical contact:* The main threat from spilled oils and emulsions is physical smothering. The animals and plants most at risk are those that could come in contact with a contaminated water surface - marine mammals and reptiles, birds that feed by diving or form flocks on the water, and marine life on shorelines. Other threats include hypothermia and drowning. When fur or feathers come into contact with oil, they can become matted and lose their insulating properties. As a result, birds and mammals may die of hypothermia. The risk of drowning increases for birds because the complex structure of their feathers that allows birds to float becomes damaged.

- *Toxicity:* Oils are "toxic" in that they have the inherent potential to cause adverse effects in living organisms. However, the degree of toxicity is determined by the type of oil, concentration, duration of exposure, and sensitivity of the receptor organism. Sensitivity to toxic compounds varies greatly by species, by life stage within a species, and by individual. In general, younger stages are more sensitive than adults. Individual characteristics, like age, sex, and contamination history are important in determining the degree of impact.

  Toxic effects may be either acute or chronic. Acute toxicity is an immediate impact that leads to the death of the individual. Since the most toxic components in oil tend to rapidly evaporate, lethal concentrations leading to large scale mortalities are relatively rare, localized and short-lived. Chronic effects may not be evident immediately and may not cause the death of the individual. However, they can impact the physiology, behavior, or reproductive capacity of the individual and may ultimately impact the survival rates of the species affected.

  Toxic effects can come from the inhalation, ingestion, or skin absorption of oil. Oil vapors can cause damage to the animal's central nervous system, liver, and lungs. Ingestion of oil can reduce the animal's ability to digest food by damaging cells in the intestinal tract. Ingested oil can also create reproductive problems, such as depressed egg laying rates and reduced hatchling survival rates for birds.

Bioaccumulation is the uptake of a contaminant by an organism directly from water or through the consumption of contaminated food. Individuals that live in contaminated environments may appear healthy but still contain elevated levels of petroleum compounds in their tissues. Bioaccumulation can result in chronic effects to the individual and may cause potential food chain problems for both mammalian and avian species.

- *Disruption of ecosystems*: Effects can include the temporary displacement of some species, alterations in predator-prey interactions, changes in hunting or fishing locations, disruption of migratory patterns, and temporary or permanent loss of habitat. Secondary impacts may occur in association with cleanup activities as a result of soil compaction, removal of trees and brush and additional loss of habitat. Differential mortality rates resulting from oil spills can impact the relationships between organisms in the food chain. Individual organisms may experience changes in food or other resource availability, as well as changes in competition and predation from other species. Even species that are not directly in contact with oil can be harmed by a spill. Predators that consume contaminated prey can be exposed to oil through ingestion. Because oil contamination gives fish and other animals unpleasant tastes and smells, predators will sometimes refuse to eat their prey and will begin to starve. On the population level, species that are dependent on affected prey or habitats will decline while opportunistic species may increase.

The sensitivity of fish to oil spills varies by species and age. In general, fish are very sensitive to short-term acute exposures but are able to metabolize sub-lethal intakes. Fish can be affected through ingestion of oil or oiled prey, absorption of dissolved petroleum products through the gills, or by changes in the ecosystem. Damage to fish eggs and larvae may also occur which can cause the smothering of eggs, interference with hatching, or developmental abnormalities. Many physiological abnormalities caused by exposure to crude oil have been documented. The youngest fish are most vulnerable to oil spills; older fish may have a mucous coating that helps them resist contact with toxic oil constituents. Large fish kills are unusual in open water environments but enclosed habitats, such as lakes or marshes, may concentrate oil enough to cause acutely toxic conditions.

Birds experience a variety of effects when exposed to oil. The primary direct effect is the fouling of plumage. Oil causes disruption of the fine structures that form the feathers, resulting in the loss of their water-repellent characteristics. The oiled plumage becomes matted which allows water to penetrate to the body surface, resulting in chilling and hypothermia and a loss of buoyancy. Birds can readily ingest oil during preening or by consuming contaminated prey. The effects of ingested oil include anemia, pneumonia, intestinal irritation, kidney damage, altered blood chemistry, decreased growth, and decreased production and viability of eggs. Anemia is normally the most severe effect and anemic birds cannot forage for food. The direct exposure of eggs to oil also has a high potential for damage with exposure in the early stages of incubation considered the most toxic.

Terrestrial animals, if not initially trapped in the oil, can usually leave the area of a spill and go to adjacent uncontaminated areas. In most cases, this behavior should minimize impacts such that adverse effects are short-lived and insignificant. However, changes in the food chain or in the habitat could result in significant negative impact for localized populations if there are no other suitable areas in the vicinity.

Fires or explosions associated with oil spills can pose an additional hazard to wildlife. While most biological communities have adapted to wildfires, petroleum-fed fires may bum hotter than other types of fires, which would increase the potential for long-term impacts. Such fires can result in immediate loss of individuals, reductions in population, and loss in biodiversity. Fires over rivers or streams can cause fish kills in the immediate and downstream areas due to changes in water temperature and consumption of the dissolved oxygen in the water. If the spill site is near populated areas, fire could pose an immediate threat to human health and safety as well.

Rare species, small local populations, or species that are seasonally concentrated in the impacted habitat are the most likely to decline as a result of an oil spill. The time necessary for oil-damaged populations of animals and plants to recover is highly variable and the extent to which the biological recovery of a habitat can be accelerated is severely limited.

1.2.6 Human Health and Safety

Impacts on human health and safety may occur in both the general public and occupational workers. The main health concern is from the known carcinogenicity of several oil components including benzene, toluene, xylene, and lead. Exposure to toxic elements in oil may occur through direct exposure or consumption of oil-tainted food or contaminated drinking water.

Public Health and Safety

The potential impact on public health of the gasoline additive MtBE is a major area of investigation at the current time. As discussed earlier, instances of MtBE contamination of ground water have been identified in various locations throughout the country. In a few cases, the contamination was severe enough to require the use of alternate drinking water supplies due to consumer odor and taste concerns. Currently there are no data on the effects on humans of drinking MtBE-contaminated water. In laboratory tests on animals, cancer and non cancer effects occurred at high levels of exposure. The tests were conducted by inhalation exposure or by introducing the chemical in oil directly to the stomach. Because the animals were not exposed through drinking water, there is significant uncertainty about the degree of risk associated with human exposure to MtBE at the low concentrations typically found in drinking water. However, these results support a concern for a potential human hazard.

In December 1997, the EPA issued an advisory on MtBE in drinking water, recommending control levels for taste and odor acceptability. MtBE concentrations of 20 to 40 micrograms per liter or below should avert the unpleasant taste and odor effects for most people. Concentrations in this range are 20,000 to 100,000times lower than the range of exposure levels resulting in cancer and non cancer effects in rodents. This exposure margin is typical of those used in the establishment of the National Primary Drinking Water Standards for other chemicals. In September 1999, the EPA's Blue Ribbon Panel recommended that the use of MtBE be reduced substantially. The EPA is continuing to evaluate available information and is doing additional research to seek more definite estimates of the potential human health risks.

Other more immediate human health effects from oil spills are possible but rare. Injury and death are possible, normally associated with occupational exposures during cleanup and disposal activities, or a fire or explosion following the spill. While the probability of a fire or explosion in a populated area may be small, the consequences can be catastrophic. For example, in June 1999, a pipeline rupture near Bellingham, Washington discharged several thousand barrels of gasoline into a local creek. The spill spread downstream causing explosions and fires in the downtown area. Three people were killed and eight others were injured.

Occuvational Health and Safety

Workers can be exposed to significant health risks if appropriate health and safety plans are not followed during cleanup and remediation operations. Sources of occupational risk range from those associated with heavy equipment operation to exposure to various chemicals. Inhalation of certain petroleum vapors for short periods may cause nausea, eye irritation, increased blood pressure, headache, light-headedness, loss of appetite, poor coordination, and difficulty concentrating. In addition, the International Agency for Research on Cancer has determined than some heavy fuel oils possibly cause cancer in humans.

Petroleum products meet the definition of a hazardous substance in OSHA's Hazardous Waste Operations and Emergency Response (HAZWOPER) standard through their inclusion in DOT's hazardous materials list (29 CFR 1910.120(a)(3)). Consequently, oil spill clean up workers and emergency responders are covered by HAZWOPER and must be trained accordingly.

1.2.7 Economic Impacts and Land Use

The economic impacts of an oil spill can be harder to quantify than those discussed in earlier sections. Economic losses may be less observable and placing a value on noncommercial activities, like recreational fishing, can be difficult. Consideration of damage to "existence" or "nonuse" values, like the intrinsic beauty of a scenic beach, may be controversial.

Economic impacts can include property damage, reduced property values, and short-term or permanent disruptions in specific industries. For example, marine spills can have a devastating effect on local fisheries. Boats and gear can be directly damaged and fish stocks can be temporarily depleted. Loss of market confidence may result in the public being unwilling to purchase marine products from the region irrespective of whether the seafood is actually tainted. Shorelines and near shore areas also serve as major recreational and tourism resources. Oil spills, and their associated cleanup, can have major impacts on the quality of these resources.

Oil spills on land can result in the contamination of vegetation, soil, crops, grazing lands, and recreational facilities. **A** small spill (two to five gallons) would most likely be confined to the pipeline right-of-way but larger spills could potentially affect areas hundreds of feet from the pipe. The removal of contaminated materials would likely require the grading and removal of soil with a resulting loss of vegetation. The temporary disruption to actual land use or recreational activities as a result of cleanup operations could be significant but short-term in most cases. However, it is possible that the quality and value of the land or recreational resource could suffer long-term adverse effects due to the continued presence of contaminated materials or the visual degradation of the area.

References

"Achieving Clean Air and Clean Water: The Report of the Blue Ribbon Panel on Oxygenates in Gasoline," U.S. EPA, July 1999.

"An Introduction to Coastal Habitats and Biological Resources for Oil Spill Response," Natic nal Oceanic and Atmospheric Administration, Report No. HMRAD 92-4.

"Calculating the Cost of Natural Resource Damage," Rebecca Renner, Environmental Scienc≥ & Technology, February 1, 1998.

"Drinking Water Advisory: Consumer Acceptability Advice and Health Effects Analysis on Methyl Tertiary-Butyl Ether (MtBE)," U.S. EPA, EPA-822-F-97-009, December 1997.

"Environmental Assessment of the Proposed Longhom Pipeline System," US EPA and US COT, October 29, 1999.

"Fate and Effects of Marine Oil Spills," International Tanker Owners Pollution Federation.

Fate of Pollutants in the Air and Water Environments, I. H. Suffet, 1977.

Groundwater Contamination and Emergency Response Guide, J. H. Guswa & W. J. Lyman, Noyes Publications, 1984.

"Marine Oil Spills: To Clean or Not To Clean? A Conversation with Michael Foster," Environmental Review Newsletter, Vol. 3, No. **4,** April 1996.

"Oil and Nature," U.S. Fish and Wildlife Service.

"Oil **Spill** Response Handbook," Oil-Spill-Web, FlemmingHvidbak.

Oil Spills, Don Nardo, Lucent Books, 1990.

"Olympic Pipeline Fire Incident Report," U.S. National Response Team Sitrep One and Two, June 11, 1999.

"Toxicological Profile for Automotive Gasoline," U.S. Public Health Service Agency for Toxic Substances and Disease Registry, 1995.

"Toxicological Profile for Fuel Oils," U.S. Public Health Service Agency for Toxic Substances and Disease Registry, 1995.

"Understanding Oil Spills and Oil Spill Response," U.S. EPA, Publication 9200.5-105, July 1993.

Various Specialist Reports from the "Yellowstone Pipeline Missoula to Thompson Falls Reroute Environmental Impact Statement," U.S.D.A. Forest Service, July 1999.

Attachment H:
December 23, 2025 Emergency Special Permit

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
EMERGENCY SPECIAL PERMIT

Special Permit Information:

Docket Number:	2025-1502
Requested By:	Sable Offshore Corp. PPC
Operator ID#:	40881
Date Requested:	December 19, 2025
Issuance Date:	December 23, 2025
Expiration Date:	February 21, 2026
Code Section:	49 CFR § 195.452(h)(4)(iii)(H)

Grant of Special Permit:

By this order, subject to the terms and conditions set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS)[1] grants this emergency special permit to Sable Offshore Corp. PPC (Sable) for 124.42 miles of 24- and 30-inch diameter hazardous liquid pipelines, Lines CA-324 and CA-325 (***special permit segments***), transporting crude oil from Las Flores Canyon to Pentland in Santa Barbara, San Luis Obispo, and Kern counties, California. This emergency special permit waives compliance from 49 CFR § 195.452(h)(4)(iii)(H), which requires corrosion of or along a longitudinal seam weld be scheduled for evaluation and remediation within 180 days of discovering the condition.

I. Purpose and Need

On December 19, 2025,[2] Sable requested an emergency special permit for relief from the requirement to evaluate and remediate corrosion occurring at longitudinal seam welds within 180 days. The ***special permit segments*** are under polyurethane foam and polyethylene tape wrap insulation, which can inhibit the effectiveness of cathodic protection and contribute to a risk of corrosion due to shielding effects. Sable proposed an alternative approach to safely manage this risk, which was previously reviewed and approved as part of two state waivers issued by the California Office of State Fire Marshal (OSFM) on December 17, 2024 to Sable for the ***special permit segments***. PHMSA previously reviewed the state waivers pursuant to 49 U.S.C. § 60118(d).

[1] Throughout this special permit, the usage of "PHMSA" means the U.S. Department of Transportation (DOT), Pipeline and Hazardous Materials Safety Administration, Office of Pipeline Safety.
[2] Sable submitted supplemental information related to its application on December 23, 2025.

Sable sought this special permit to implement the terms of a Consent Decree entered in Civil Action No. 2:20-CV-02415 by the U.S. District Court for the Central District of California, which provides, among other requirements, that a "State Waiver" must be applied for and received from OSFM prior to restarting Lines CA-324 and CA-325. The ***special permit segments*** were previously considered intrastate at the time of entry of the Consent Decree and were regulated by OSFM pursuant to its state certification with PHMSA under 49 U.S.C. § 60105(a). However, the ***special permit segments*** are now considered interstate pursuant to Sable's designation on November 26, 2025, and PHMSA's concurrence on December 17, 2025. As a result, PHMSA has exclusive pipeline safety regulatory agency over Lines CA-324 and CA-325. The conditions ordered by OSFM in the two state waivers are now being re-issued by PHMSA as a special permit subject to Federal oversight and enforcement.

Sable requested PHMSA grant a special permit for the above reasons on an emergency basis pursuant to 49 U.S.C. § 60118(c)(2) and 49 CFR § 190.341(g). In its application, Sable stated that expedited review of its application was warranted in light of the national energy emergency declared by the President under the National Emergencies Act (50 U.S.C. § 1601 et seq.) in Executive Order 14156 (January 20, 2025). In Executive Order 14156, the President declared a national energy emergency based on a finding that "[t]he United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[3] The Executive Order directs agencies, such as PHMSA, to "identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate," among other activities, the "production, transportation, refining, and generation of domestic energy resources."[4] The Executive Order further directs agencies to "identify and use all lawful emergency or other authorities available to them to facilitate the supply, refining, and transportation of energy in and through the West Coast of the United States . . . ."[5]

Sable's application stated that grant of this special permit on an emergency basis would facilitate the restart of Lines CA-324 and CA-325 to provide relief in response to the acute energy shortage conditions identified in Executive Order 14156 within California and in the West Coast region of the United States.[6] Sable further noted that grant of this special permit on an emergency basis is appropriate to address the gap in coverage under the OSFM State Waivers created by redesignation of Lines CA-324 and CA-325 as interstate, given that the proposed special permit is substantially the same as that which was previously reviewed and approved by OSFM and PHMSA for issuance of the State Waivers.

This emergency special permit allows Sable to operate Lines CA-324 and CA-325 without being subject to the requirement to evaluate and remediate corrosion of or along a longitudinal seam weld within 180 days. On the condition that Sable comply with the terms and conditions set forth below, the emergency special permit waives compliance with 49 CFR § 195.452(h)(4)(iii)(H) for the ***special permit segments***.

[3] Exec. Order 14156: Declaring a National Energy Emergency (Jan. 20, 2025), Sec. 1.
[4] Exec. Order 14156: Declaring a National Energy Emergency (Jan. 20, 2025), Sec. 2(a). The order's definition of "energy" or "energy resources" includes "crude oil," and its definition of "transportation" includes "the physical movement of energy, including through, but not limited to, pipelines." Sec. 1(a); 1(c).
[5] Exec. Order 14156: Declaring a National Energy Emergency (Jan. 20, 2025), Sec. 3(b).
[6] For more information regarding these effects, see Attachments C, D, E, and F.

II. Special Permit Segments

This emergency special permit pertains to the specified pipeline segments which make up the Las Flores Pipeline called Line CA-324 and CA-325. Line CA-325 can be further divided into two segments: Lines CA-325A and CA-325B. The Las Flores Pipeline is part of the Santa Ynez Pipeline System (SYPS), an interstate pipeline facility that Sable operates from the Outer Continental Shelf off the coast of Santa Barbara to Kern County, California. A map of the special permit segments is available in Revised Attachment A.

Special Permit Segments:

Special Permit Segment Name	Location	Mileage	California County or Counties
CA-324	Las Flores Canyon Processing Facility to Gaviota Pump Station	10.86	Santa Barbara
CA-325A	Gaviota Pump Station to Sisquoc Pump Station	38.72	Santa Barbara
CA-325B	Sisquoc Pump Station to Pentland Station	74.84	Santa Barbara; San Luis Obispo; Kern

III. Conditions

PHMSA grants this emergency special permit subject to Sable implementing each of the following conditions. These conditions must be implemented and complied with in addition to all applicable requirements of 49 CFR Part 195 except for compliance with limitations on scheduling instances of corrosion on or near longitudinal seam welds for evaluation and remediation within 180 days of discovery in 49 CFR § 195.452(h)(4)(iii)(H), which would be waived.

General Conditions:

1) The ***special permit segments*** may only be used to transport crude oil.

2) Prior to transporting crude oil in the ***special permit segments***, Sable must develop and implement procedures for the conditions and requirements described in this emergency special permit.

3) Sable shall not exceed maximum operating pressure (MOP) limits for the ***special permit segments***, as follows:

   a) The MOP of Line CA-324 cannot exceed 1003 pounds per square inch gauge (psig).

   b) The MOP of Line CA-325A (the segment of Line CA-325 between Gaviota and Sisquoc stations) cannot exceed 1000 psig.

c) The MOP of Line CA-325B (the segment of Line CA-325 between Sisquoc and Pentland stations) cannot exceed 1292 psig.

4) Sable shall not exceed maximum operating temperature limits for crude oil transported in the ***special permit segments***, as follows:

a) The maximum operating temperature of the crude oil that is transported in Line CA-324 must not exceed 140 degrees Fahrenheit for more than 12 consecutive hours.

b) The maximum operating temperature of the crude oil that is transported in Line CA-325A (the segment of Line CA-325 between Gaviota and Sisquoc stations) must not exceed 125 degrees Fahrenheit for more than 12 consecutive hours. Temperature transmitters must be installed on Line CA-325 at Gaviota station to monitor the temperature of Line CA-325A.

c) The maximum operating temperature of the crude oil that is transported in Line CA-325B (the segment of Line CA-325 between Sisquoc and Pentland stations) must not exceed 110 degrees Fahrenheit for more than 12 consecutive hours. Temperature transmitters must be installed on Line CA-325 at Sisquoc station to monitor the temperature of Line CA-325B.

5) This emergency special permit does not relieve Sable from complying with applicable requirements under 49 CFR Part 195, other than those waived in this emergency special permit.

6) This emergency special permit 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 inspections (ILIs) performed pursuant to this emergency special permit must include:

a) Use of a tool that is at least capable of reliably detecting and identifying cluster corrosion and general corrosion, defined 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-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)[7], and the HF-ERW long seam weld on the pipe to represent the fracture toughness of 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 11, 16, 17, and 21. Sable may use pipe samples taken opportunistically during ongoing maintenance and repair efforts on Line CA-324.[8]

9) Prior to placing Line CA-325 (including CA-325A and CA-325B) 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), 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 11, 16, 17, and 21. Sable may use pipe samples taken opportunistically during ongoing maintenance and repair efforts on Line CA-325A/B.[9]

10) All existing immediate and 180-day repair conditions must be evaluated and remediated pursuant to the Consent Decree repair criteria prior to restarting CA-325A/B.[10] Upon restart 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 PHMSA. Sable must utilize the Ultrasonic Thickness Wall Measurement (UTWM) and Ultrasonic Shear Wave Crack Detection (USCD) in-line inspection (ILI) results to identify, evaluate and remediate any immediate and 180-day repair conditions that are listed in this emergency special permit.

11) 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

[7] The heat affected zone (HAZ), as used in this emergency special permit, is defined as a 1-inch-wide area on either side of the longitudinal weld seam.

[8] Sable indicated in its application that it has already completed all of the testing required in this condition. Sable must submit all fracture toughness results to PHMSA prior to restarting Line CA-324.

[9] Sable indicated in its application that it has already completed the testing required in this condition. Sable must submit all fracture toughness results to PHMSA prior to restarting Line CA-325.

[10] Sable indicated in its application that it has already completed the repairs required in this sentence. Sable must submit all of the results to PHMSA prior to restarting CA-324 and CA-325.

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.

12) Sable must utilize cleaning pigs at regular intervals not to exceed a biweekly basis to maintain adequate cleanliness on the internal pipe wall of CA-324 and CA-325A/B.

13) Pressure Testing:[11]

a) Prior to placing CA-324 in operation, Sable must conduct a spike hydrostatic pressure test of CA-324 at a minimum pressure that is at least 1.5 times the maximum operating pressure (MOP) or 100% specified minimum yield strength (SMYS), for a minimum of 15 minutes after the spike test pressure is stabilized. Sable must field evaluate and remediate the following anomalies before performing the spike hydrostatic test on CA-324:

i. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.

ii. All anomalies that have a predicted failure pressure less than or equal to 1.6 times MOP.

b) Immediately following the spike hydrostatic pressure test specified in Condition 13(a), Sable must conduct an 8-hour hydrostatic pressure test of CA-324 at a minimum of 1.25 times the MOP.

c) Prior to placing Line CA-325A (segment of Line 325 between Gaviota and Sisquoc stations) in operation, Sable must conduct a spike hydrostatic pressure test of 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:

i. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.

ii. All anomalies that have a predicted failure pressure less than or equal to 1.5 times MOP.

d) Immediately following the spike hydrostatic pressure test specified in Condition 13(c), Sable must conduct an 8-hour hydrostatic pressure test of CA-325A at a minimum of 1.25 times the MOP.

e) Prior to placing Line CA-325B (segment of Line 325 between Sisquoc and Pentland stations) in operation, Sable must conduct a hydrostatic pressure test of 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

[11] Sable indicated in its application that it has already completed all of the testing and repairs required in this Condition. Sable must submit the results to PHMSA prior to restart and confirm that no failures occurred during the required pressure testing.

hydrostatic test on CA-325B:

i. All metal loss anomalies that have an ILI reported depth of 40% and greater wall loss.

ii. All anomalies that have a predicted failure pressure less than or equal to 1.4 times MOP.

f) Sable must obtain the Test ID for each hydrostatic pressure test from PHMSA (or OSFM if such testing was performed prior to November 26, 2025) and have the approved independent testing firm forward separately the certified test results to PHMSA or the OSFM, as applicable.

g) Each hydrostatic pressure test must be performed in accordance with the applicable requirements of 49 CFR Part 195 Subpart E – Pressure Testing and monitored by an independent testing firm listed under PHMSA or OSFM (as applicable) approved hydrostatic testing companies.

h) Failures resulting from the spike hydrostatic pressure test or the 8-hour strength test shall be immediately reported to PHMSA.[12]

i) Section(s) of the ***special permit segments*** that failed during the required hydrotesting must be repaired by removing and replacing the failed section. PHMSA reserves the right to revoke this emergency special permit if failure(s) raise the concern that the ***special permit segments*** cannot be safely operated.

14) In-Line Inspection (ILI) Assessment and Frequency:

a) Prior to performing in-line inspections of the ***special permit segment***, Sable shall provide PHMSA with a written notification to PHMSA describing its assessment plan with the following information:

i. Dates for integrity assessment

ii. In-line inspection tool(s) selected, in accordance with API Standard 1163 Section 5 and NACE SP0102[13] 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;

iii. In-line inspection tool vendor(s)

iv. Required tool specifications including operational specifications and anomaly sizing tolerances

v. Tool validation methodology

vi. Anomaly feature identification criteria and reporting thresholds – wall loss, dents, internal corrosion, external corrosion, cracks, and crack-like indications

[12] All submissions to PHMSA required by this emergency special permit shall be submitted through email to the OPS Western Region Director, Dustin Hubbard, email address: Dustin.Hubbard@dot.gov or his designee.

[13] Industry standards referenced in this emergency special permit must utilize the editions that are incorporated by reference in 49 CFR 195.3 unless another edition is explicitly specified in this emergency special permit.

vii. Criteria used to identify locations for excavation and field verification

viii. Non-destructive examination

b) 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.

c) Metal Loss Tool(s):

i. Initial ILI tool runs – Each year, during the first two (2) years of operating the ***special permit segments***, 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.

ii. Subsequent ILI tool runs – After the first two (2) years of operating the ***special permit segments***, 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 ***special permit segment*** within 30 days after it was deemed to be unsuccessful. All metal loss tool runs must also utilize an Inertial Measurement Unit (IMU).

d) 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[14] or the ILI assessment must be assessed at more frequent intervals if condition 21 determined a shorter assessment interval.

i. These crack tool runs must utilize an Inertial Measurement Unit (IMU) and must be able to detect and size axial and circumferential cracks.

ii. USCD Performance Specification Requirements

1. The USCD tools must have a probability of detection that is

[14] Sable may petition PHMSA 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 PHMSA approval.

≥ 90% for axial and circumferential cracks.

2. 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.
3. 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.
4. The depth sizing accuracy for cracks must be ± 0.8 mm for axial cracks and ± 1 mm for circumferential cracks.

e) Dents and Pipe Deformation: Sable shall conduct a high-resolution deformation ILI tool with each UTWM.

f) 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 ***special permit segment*** in which the ILI tool velocity was outside of the specified tool velocity range.

g) All ILI tool runs must obtain the Test ID from PHMSA prior to run.

h) 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.

i) 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.

j) 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[15] 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.

k) 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

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

Edition, April 2013).

15) Discovery of Condition: The discovery date must be within 180 days of any ILI tool run for each type of ILI tool.

16) Immediate Repair Conditions:[16]

a) A crack or crack-like anomaly that meets any of the following criteria:

i. Crack or crack-like anomaly that is equal to or greater than 50% of pipe wall thickness.

ii. 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.

b) Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.39 times the MOP.

c) 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.[17]

17) 180-Day Repair Conditions:[18]

a) A crack or crack-like anomaly that has predicted failure pressure of less than 1.5 times the MOP.

b) Internal or external metal loss anomalies where the remaining strength of pipe shows a predicted failure pressure less than 1.5 times the MOP.

c) 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.[19]

d) 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.

18) Corrosion Growth Rate Analysis (CGRA):

a) Sable must develop a CGRA procedure to annually calculate corrosion growth rates between successive ILI's (using most recent ILI compared to

[16] The criteria specified in this emergency special permit is supplemental to, and does not relieve Sable from complying with, the requirements set forth in 49 CFR 195.452(h)(4)(i). All immediate repair conditions must be remediated with a permanent repair method.

[17] 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.

[18] The criteria specified in this emergency special permit is supplemental to, and does not relieve Sable from complying with, the requirements set forth in 49 CFR 195.452(h)(4)(iii), except for those associated with 49 CFR 195.452(h)(4)(iii)(H). All immediate repair conditions must be remediated with a permanent repair method.

[19] 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 PHMSA, temporarily reduce the operating pressure, and take further remedial action in accordance with 49 CFR § 195.452 until the indication is remediated or until otherwise authorized by PHMSA.

prior ILI) and perform pipeline remediations needed to assure the integrity of the ***special permit segments*** is maintained.[20] The timing of remediations under this condition shall be based on the most recent calculation of short-term corrosion rates.

b) The CGRA procedure must include ILI data matching methods[21] to analyze data from successive ILI's, methodologies for growth rate calculations and errors from comparing ILI data.

c) Sable must identify the projected date when remaining metal loss indications will reach a depth of 70% or greater wall loss.

d) 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.[22]

e) 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.

19) Pressure Reduction: If Sable is unable to perform field evaluation and remediation of any required conditions within the time limit conditions specified in this emergency special permit, 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.

20) In Field Direct Examination of Pipe:

a) Direct examinations[23] 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).[24] PAUT must be used for sizing any crack or crack-like anomaly lengths and depths.

b) 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:

i. Method 5 must not be used on metal loss anomalies that are in the HAZ, girth weld, or longitudinal seam weld.

ii. Sable must increase the metal loss anomaly's depth by 20% when

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

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

[22] 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.

[23] 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.

[24] Direct examinations for ILI reported crack or crack-like indications must include a magnetic particle inspection complemented by shear wave technology or inspection by phased array ultrasonic testing.

they input it into the formula for calculating the number of wraps needed for repair method 5.

iii. 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.

c) 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.

d) 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.[25]

e) 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.

21) Integrity Management:

a) A fracture mechanics and pressure cycling evaluation is required for un-remediated cracks and crack-like indications detected by ILI or indirect inspection tools.

i. 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 CFR § 192.712(d)(1).

ii. Sable must perform a fatigue analysis using an applicable fatigue crack growth law or other technically appropriate engineering methodology in accordance with 49 CFR § 192.712(d)(2).

b) 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.

c) When sizing metal loss indications, apply interaction/clustering criteria of 6t by 6t for applicable ILI tool(s).

d) Sable must send all field measurements to the ILI tool vendor within 90 days

[25] The coating procedure must be submitted to PHMSA prior to the effective date of this emergency special permit.

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.

e) 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 ***special permit segments***. The review must be conducted within six (6) months of each ILI assessment. The third-party expert must be approved by PHMSA prior to being selected.

f) 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

g) occurring. The expert must recommend the frequency of subsequent interference surveys. All evaluations must be approved and signed by the NACE-certified expert.

22) Data Requirements for Predicted Failure Analysis:

a) 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.

b) The analyses performed in accordance with this emergency special permit must utilize pipe and material properties of the pipe body and longitudinal weld seam that are documented in traceable, verifiable, and complete records.

23) Recordkeeping:

a) Procedures, records of investigations, data, analyses, and other actions made in accordance with the requirements of this emergency special permit shall be kept for the life of the ***special permit segments*** and must be submitted to PHMSA, in the manner requested (electronic, hardcopy, or other format) within 30 days.

b) Sable must maintain the following records:

i. Technical approach used for the analysis

ii. All data used and analyzed

iii. Pipe and longitudinal weld seam properties

iv. Procedures used to implement emergency special permit conditions

v. Evaluation methodology used

vi. Models used

vii. Direct in situ examination data

viii. All in-line inspection tool assessments information evaluated

ix. Pressure test data and results

x. All in-the-ditch assessments performed on the ***special permit segments***

xi. All measurement tool, assessment, and evaluation accuracy specifications and tolerances used in technical and operations results

xii. All finite element analysis results

xiii. The number of pressure cycles to failure, the equivalent number of annual pressure cycles, and the pressure cycle counting methodology

xiv. The predicted fatigue life and predicted failure pressure from the required fatigue life models and fracture mechanics evaluation methods

xv. Safety factors used for fatigue life and/or predicted failure pressure calculations

xvi. Reassessment time interval and safety factors

xvii. The date of the review

xviii. Confirmation of the results by qualified technical subject matter expert(s)

xix. Approval by responsible Sable management personnel

xx. Records of additional preventive and mitigative (P&M) measures performed

xxi. Reports required by this emergency special permit.

24) Reporting:

a) Any release on the ***special permit segments*** shall be reported to PHMSA at the earliest practicable moment following discovery but no later than 24 hours from the time of discovery.[26]

b) An email notification shall be made at least three (3) days prior to a ***special permit segment*** being exposed for non-emergency purposes of field evaluation and repair to PHMSA. The email notification shall include, if applicable:

i. Tool type and run date

ii. Unique identifier (e.g. Dig Number, Joint Number, Flaw ID, Condition Type)

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

iii. Dig sheets

iv. Field contact information for Sable

v. Time and location of the field evaluation and repair.

c) Sable shall provide a Summary of Conditions Report within 210 days of the last date of an ILI run to PHMSA and include:

i. Tool type

ii. Run date

iii. Summary of Conditions Report[27]

iv. Final Vendor Report and Pipe Tally

d) Sable shall provide a report to PHMSA by June 15th of every year for the duration of this special permit, including any renewals. The report shall be submitted to PHMSA. At a minimum, the annual report shall contain the following, if applicable:

i. A Closure Report for the previous calendar (CY) which contains:

1. Features that were remediated in previous CY, including documentation for in-the-ditch assessments and repairs

2. Identify features that remain to be assessed

3. Unity Plots for previous ILI runs

ii. Fracture mechanics and pressure cycling analyses in accordance with Condition 21(a);

iii. The third-party ILI expert reviews in accordance with condition 21(e).

iv. AC and DC Interference surveys that are due in accordance with condition 21(f).

v. A copy of the CGRA for prior year including:

1. Mean corrosion growth rate for the ***special permit segments***

2. Distribution graph of the corrosion growth rate for the ***special permit segments*** (e.g. occurrences (#) vs. corrosion rate (mpy)

The above conditions are based on PHMSA's review and consideration of information provided by Sable, including information in their emergency special permit application which can be found at Docket No. PHMSA-2025-1502 in the Federal Docket Management System located at www.regulations.gov. PHMSA has determined the conditions listed above would be necessary to ensure this Emergency Special Permit is not inconsistent with pipeline safety.

[27] PHMSA 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.

IV. Limitations:

This special permit is subject to the limitations set forth in 49 CFR § 190.341, as well as the following limitations:

1) This emergency special permit is limited to an initial term of sixty (60) days from the date of issuance. If Sable elects to seek renewal of this emergency special permit, it must submit a renewal request to PHMSA pursuant to 49 CFR § 190.341(g).

2) Should Sable fail to comply with any conditions of this emergency special permit or should PHMSA determine that this emergency special permit is no longer appropriate or is inconsistent with pipeline safety, PHMSA may revoke the emergency special permit and require Sable to comply with all appropriate regulatory requirements.

3) PHMSA may order the ***special permit segments*** to be shutdown at any time.

4) PHMSA 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 emergency special permit. The terms and conditions of any compliance order shall take precedence over the terms of this emergency special permit.

5) In the event of conflict between the conditions of this emergency special permit and industry standards, the emergency special permit conditions shall prevail.

6) If Sable sells, merges, transfers or otherwise disposes of all or part of the assets covered by the emergency special permit, Sable must provide PHMSA written notice of the change within 60 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the emergency special permit.

AUTHORITY: 49 United States Code 60118 (c)(1) and 49 CFR § 1.97.

Issued in Washington, D.C., on December 23, 2025.

Linda Daugherty
Acting Associate Administrator
for Pipeline Safety