January 2, 2024 MIR-24-01

Anchor Strike of Underwater Pipeline and Eventual Crude Oil Release

San Pedro Bay

Near Huntington Beach, California

October 1, 2021

Abstract: This report discusses the October 1, 2021, crude oil release resulting from contact of ships' anchors with an underwater pipeline in San Pedro Bay near Huntington Beach, California. Safety issues identified in this report include insufficient distance between anchorage locations and the pipeline, need for notification of potential pipeline damage to the pipeline operator, need for improvements to Vessel Traffic Service vessel monitoring systems, incorrect response by pipeline controllers to leak alarms, lack of postaccident alcohol and other drug testing for pipeline controllers, and the need for pipeline operators to implement pipeline safety management systems. As a result of this investigation, the National Transportation Safety Board makes six new safety recommendations to the Pipeline and Hazardous Materials Safety Administration, US Coast Guard, and the Marine Exchange of Southern California.

Contents

Figures

Tables

Acronyms and Abbreviations

AIS	automatic identification system
ANSI	American National Standards Institute
API	American Petroleum Institute
BSEE	Bureau of Safety and Environmental Enforcement
CAO	corrective action order
CFR	*Code of Federal Regulations*
ECDIS	electronic chart display and information system
ETO	electro-technical officer
HCA	high consequence area
LA-LB	Los Angeles-Long Beach
MAREX	Marine Exchange of Southern California
NOAA	National Oceanic and Atmospheric Administration
NRC	National Response Center
NTSB	National Transportation Safety Board
PHMSA	Pipeline and Hazardous Materials Safety Administration
psig	pounds per square inch gauge
PSMS	pipeline safety management system
ROV	remotely operated vehicle
RP	recommended practice
SCADA	supervisory control and data acquisition
VTS	vessel traffic service

Glossary

Breakwater: an offshore structure (such as a wall) protecting a harbor or beach from the force of waves.

Hawsepipe: a cast-iron or steel pipe placed in the bow of a ship on each side of the stem for the anchor chains to pass through.

In-line inspection: an inspection method in which a highly specialized tool is passed within a pipeline to inspect the pipeline from the inside. In-line inspections use nondestructive examination techniques to identify, locate, and size various damages and defects, depending on the type of tool.

Letting go the anchor: deploying the anchor by dropping it from the vessel to the sea floor.

Payed out: let out a rope or chain gradually.

Right-of-way: a pipeline right-of-way over water is a strip of water surface and subsurface where a pipeline operator is permitted to install, operate, maintain, and access a pipeline that crosses a body of water, such as a river, lake, or ocean. A pipeline right-of-way over water may have certain restrictions on what activities are allowed on or near the pipeline, such as anchoring, fishing, dredging, or drilling. A pipeline right-of-way over water may also have certain environmental and safety requirements to protect the water quality and marine life.

Shot: also known as a shackle, a shot of anchor chain is 15 fathoms, or 90 feet, in length.

TEU: a measure of the carrying capacity of a containership based on the number of 20-foot-long containers the vessel is capable of loading (standard shipping container lengths are 20 and 40 feet).

Unified command: a system of command that allows different agencies or services to coordinate an effective response to an incident, while maintaining their own authority and responsibility. Under a unified command, the incident commanders of the major organizations involved in the incident work together to establish a common set of objectives and strategies, share information, and maximize the use of available resources.

Executive Summary

What Happened

On October 1, 2021, at 1610 local time, San Pedro Bay Pipeline controllers received the first of a series of leak detection system alarms for their underwater pipeline, which was located in San Pedro Bay, 4.75 nautical miles off the coast of Huntington Beach, California. Over the next 13 hours, the controllers conducted seven pipeline shutdowns and restarts during troubleshooting of the alarms. At 0604 on October 2, controllers shut down the pipeline for the eighth and final time. A pipeline contractor vessel crew visually confirmed a crude oil release at 0809, and Beta Offshore, the pipeline operator, then initiated an oil spill response. An estimated 588 barrels of oil leaked from the pipeline. Damage, including clean-up costs, was estimated at $160 million. There were no injuries. A postaccident underwater examination of the pipeline found a crack along the top of the pipeline within a section of the pipeline that had been displaced from its originally installed location. Additionally, scarring consistent with anchor dragging was identified on the seafloor near the crack location. Postaccident investigation determined that the containerships *MSC Danit* and *Beijing* had dragged anchor near the pipeline months before the oil release, on January 25, 2021.

What We Found

We found that the release of crude oil occurred as a result of fatigue failure that manifested over a period of time in an area of local deformation to the San Pedro Bay Pipeline caused by an external force that resulted in progressive cracks initiating and growing through the pipe wall until the pipe wall ruptured.

Postaccident examination of vessel traffic in the area determined that on January 25, 2021, vessels anchored nearby were subjected to high winds and seas generated by a strong cold front. As a result, the containerships *Beijing* and *MSC Danit* dragged anchor, and the anchors struck, displaced, and damaged the San Pedro Bay Pipeline. We determined that the *MSC Danit* anchor's contact with the pipeline was the initiating event that led to the eventual crude oil release.

We also found that, because of the proximity of the anchorage positions that the *Beijing* and *MSC Danit* were assigned to and the pipeline, the crews had insufficient time and space to heave in their dragging anchors in high winds and seas before the anchors contacted the pipeline. The southeast boundary of the anchorage and the location of contingency anchorage positions southwest of the anchorage did not leave a sufficient margin of safety between anchored vessels and the pipeline.

Following the anchor dragging events, the pipeline operator was not notified by either the vessels or Vessel Traffic Service (VTS) Los Angeles-Long Beach. The VTS watchstanders did not recognize the danger presented to the San Pedro Bay Pipeline by the *Beijing* and *MSC Danit* dragging anchors because they lacked a visual indicator of the location of the pipeline and they were attending to exceptionally high vessel activity due to weather; a visual and audible alarm when an anchored vessel encroaches on a pipeline would increase their awareness. Had the pipeline operator been made aware of the *Beijing* and *MSC Danit* anchor dragging, the company could have conducted an underwater survey of the pipeline, identified the damage, and made repairs, preventing the eventual release of crude oil. Further, defined procedures for informing pipeline and other utility operators when possible pipeline incursions have occurred within the VTS area of responsibility would improve the pipeline or utility operator's ability to identify and respond to any damage.

We also explored the reasons for the pipeline controllers' delay in properly responding to the pipeline leak following the first alarm. We found that abnormal operating conditions contributed to the pipeline controllers' incorrect determination that the leak alarms were false. Had the controllers responded in accordance with company procedure for a leak by shutting down and isolating the pipeline, they would have significantly reduced the volume of crude oil released and the resulting environmental damage. We also concluded that the insufficient training of the pipeline controllers contributed to the 14-hour delay in stopping the pipeline's shipping pumps, which consequently increased the volume of crude oil released, following the first leak alarm.

Finally, as a result of this investigation, we found that Beta Offshore was not in compliance with regulations when the company did not drug-test the pipeline controllers following the accident. We also found that pipeline safety would be enhanced if pipeline companies implemented safety management systems, and that Beta Offshore may have further evaluated their operations, identified continuous improvement opportunities, and better positioned their staff to respond and react to a leak had they implemented a pipeline safety management system.

We determined that the probable cause of the damage to and subsequent crude oil release from the San Pedro Bay Pipeline was the proximity of established anchorage positions to the pipeline, which resulted in two containerships' anchors striking the pipeline when the ships dragged anchor in high winds and seas. Contributing to the crude oil release was the undetected damage to the pipeline, which allowed fatigue cracks to initiate and grow to a critical size and the pipeline to leak nearly 9 months later. Contributing to the amount of crude oil released was Beta Offshore's insufficient training of its pipeline controllers, which resulted in the failure of the controllers to appropriately respond to leak alarms by shutting down and isolating the pipeline. Contributing to the pipeline controllers' inappropriate response to the leak alarms was the water buildup in the pipeline, an incorrect leak location indicated by Beta Offshore's leak detection system, and frequent previous communication-loss alarms.

What We Recommended

We recommended that the US Coast Guard implement the proposed VTS Los Angeles-Long Beach restructuring of the San Pedro Bay federal anchorages to increase the margin of safety between anchored vessels and the pipeline. In addition, we recommended that the Marine Exchange of Southern California, which jointly operates VTS Los Angeles-Long Beach with the Coast Guard, work with its vessel monitoring system provider to add audible and visual alarms for the system that alert the watchstander when an anchored vessel is encroaching on a pipeline. Further, we recommended that the Coast Guard implement this capability on all VTS vessel monitoring systems nationwide. Additionally, we recommended that the Coast Guard develop procedures for all VTSs to notify pipeline and utility operators following potential incursions on submerged pipelines within the VTSs' areas of responsibility.

To address the lack of drug testing of the pipeline controllers following the crude oil release, we recommended that the Pipeline and Hazardous Materials Safety Administration (PHMSA) audit Beta Offshore's drug-testing program to ensure compliance with postaccident drug-testing regulations.

Finally, to enhance pipeline safety, we recommended that PHMSA issue an advisory bulletin to all PHMSA-regulated pipeline owners and operators, promoting the benefits of pipeline safety management systems and asking them to develop and implement such a system based on American Petroleum Institute Recommended Practice 1173.

1 Factual Information

1.1 Event Narrative

1.1.1 Synopsis

On October 1, 2021, at 1610 local time, San Pedro Bay Pipeline controllers received the first of a series of leak alarms for their underwater pipeline, which was located in San Pedro Bay, 4.75 nautical miles off the coast of Huntington Beach, California.[1] Over the next 13 hours, the controllers conducted seven pipeline shutdowns and restarts during troubleshooting of the alarms. At 0604 on October 2, controllers shut down the pipeline for the eighth and final time. A pipeline contractor vessel crew visually confirmed a crude oil release at 0809, and Beta Offshore (Beta), the pipeline operator, then initiated an oil spill response (see figure 1). An estimated 588 barrels of oil leaked from the pipeline. Damage, including clean-up costs, was estimated at $160 million. There were no injuries. A postaccident underwater examination of the pipeline found a crack along the top of the pipeline within a section of the pipeline that had been displaced from its originally installed location. Additionally, scarring consistent with anchor dragging was identified on the seafloor near the crack location. Postaccident investigation determined that the containerships *MSC Danit* and *Beijing* had dragged anchor near the pipeline months before the oil release, on January 25, 2021.

[1] (a) In this report, all times in January 2021 are Pacific standard time, and all times in October 2021 are Pacific daylight time; all miles referencing the pipeline are statute miles and all miles referencing anchorages and ships are nautical miles (1.15 statute miles). (b) *Leak detection systems* are designed to detect releases that meet specific criteria (see section 1.8). They may detect *leaks* or *ruptures* if the release meets the design criteria. (c) Visit ntsb.gov to find additional information in the public docket for this NTSB accident investigation (case number DCA22FM001). Use the CAROL Query to search safety recommendations and investigations.

Figure 1. Crude oil in the Pacific Ocean off the California coast on October 3, 2021. Oil spill removal organization vessels are towing a skirted oil boom to contain the oil spill. (Source: US Coast Guard)

1.1.2 October 2021 – Crude Oil Release

1.1.2.1 Background

Underwater pipelines cross many of the nation's ports and waterways, particularly in areas where the production of oil, gas, and other petrochemical products is common. Utilities such as water and sewer lines and electrical and communications cables may also cross harbors and waterways. In shallow water, near sheltered anchorages, or in high-traffic areas, pipelines and utilities may be buried or overlayed with a protective covering, but in other areas they may lie exposed on the seafloor. Pipelines and utilities are marked on nautical charts as a single line or a corridor defined by two parallel lines.

The 17-mile-long San Pedro Bay Pipeline was owned by the San Pedro Bay Pipeline Company and operated by Beta, both of which were subsidiaries of the Amplify Energy Corporation (Amplify). The pipeline transported crude oil from a complex of four platforms (Elly, Eureka, Edith, and Ellen) located in San Pedro Bay (see figure 2). The pipeline ran from Platform Elly (mile 0) to the Beta Pump Station (mile 17.3) located in Long Beach, California. The 16-inch-diameter pipeline was constructed in 1980 of steel with a concrete weight coating. The pipeline was buried from the Long Beach Harbor breakwater to the shore. Beyond the breakwater, the underwater portion of the pipeline sat on the ocean floor. Three shipping pumps located on Platform Elly moved crude oil through the pipeline. The pumps could be operated individually or together. (See section 1.3 for more information about the pipeline.)

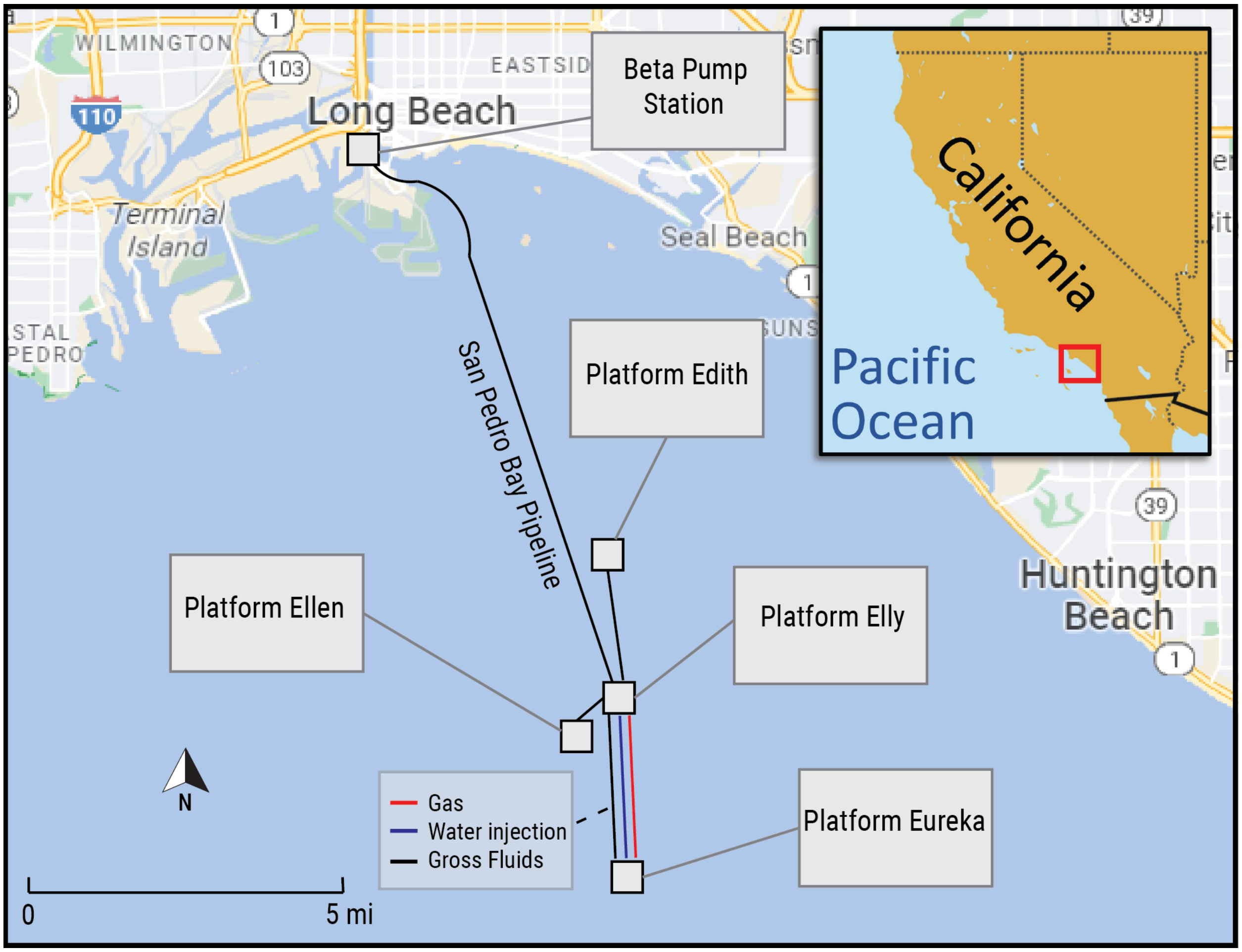

Figure 2. Simplified illustration of the San Pedro Bay Pipeline and supporting structures.

The primary pipeline personnel involved in the troubleshooting leading up to the oil release discovery consisted of two pipeline controllers (the dayshift controller and the nightshift controller) located on Platform Elly, the person-in-charge located on Platform Ellen (connected to Platform Elly by a foot bridge), the senior field technician located at Beta Pump Station, and the off-duty pipeline superintendent who was called in to the Beta Pump Station during the night of October 1.

On the afternoon of October 1, 2021, the free water knockout tank on Platform Elly, which separated water from the oil/water emulsion coming from production wells, experienced problems that resulted in up to 100 times more water entering the San Pedro Bay Pipeline than normal. During the upset, the pipeline's mixture of crude oil and water was about 50% water, rather than the normal 0.5% water. Operators spent several hours working on the issue, waking the nightshift controller about 1330 or 1400 to help troubleshoot, and they repaired the problem about 1600.

In addition to the problem with the free water knockout tank, controllers also received multiple communication-loss alarms, indicating lost communication between Platform Elly and Beta Pump Station for at least 10 seconds, throughout the day on October 1. As an example, during a 2-hour period, controllers received six communication-loss alarms. The pipeline had a history of experiencing communication-loss alarms. (See section 1.8.1 for more information about alarms.)

1.1.2.2 Leak Alarms and Oil Release Discovery

At 1610, the leak detection system alarmed, indicating a leak. The control room console showed the leak location at “Mile 0,” indicating a leak at the pipeline’s origin at Platform Elly.[2] Working together, the dayshift controller and nightshift controller decided to allow one shipping pump to continue running for about an hour (it was normal to run one pump at a time). (During this time, the controllers also received two communication-loss alarms, at 1617 and 1632.) The nightshift controller’s understanding was that the leak detection system indicated a leak on Platform Elly, not on the underwater portion of the pipeline. Further, the controllers knew that high water levels were already in the pipeline. They assumed the alarm was erroneous and activated due to the higher-than-normal water content in the pipeline’s crude oil resulting from the earlier problem with the free water knockout tank.

During the period after the first leak alarm, the dayshift controller and nightshift controller checked the pressure differentials between Platform Elly and Beta Pump Station, known as “lambdas,” generated by the leak detection system and displayed on their screens. (See section 1.8.3 for more information about the leak detection system). Increasing lambdas signal an increasing likelihood of an actual leak. When the controllers noticed that the lambdas had begun rising during the hour that the one shipping pump remained on, they decided to shut off the shipping pump to allow the pipeline to “settle.” The dayshift controller turned off the shipping pump about 1710 and allowed the pipeline to settle for about 30 minutes before restarting the shipping pump about 1740.

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[2] The leak detection system showed the leak location in miles from Platform Elly to shore. A 0 value indicated the beginning of the line at Platform Elly, and a 17.3 value indicated the Beta Pump Station.

About 1752, the leak detection system issued a second leak alarm, again indicating a leak at Mile 0. The dayshift controller shut off the shipping pump about 1753. Given the 17.3-mile length of the pipeline, once the pump was turned off, it took a few minutes for oil to stop flowing out of the pipeline to Beta Pump Station. Similarly, it took a few minutes for oil to begin flowing into Beta Pump Station after the pump was turned on. Therefore, in the minutes after the pump was turned on or off, the flow and pressure readings at either end of the pipeline diverged until the pipeline returned to steady-state operations.

About 1800, the nightshift controller assumed duty from the dayshift controller, and the dayshift controller went to rest. Sunset was at 1837.

Because the leak detection system indicated a leak at Mile 0, on Platform Elly, when the pumps were off, the nightshift controller requested the assistance of other personnel to visually check for a leak by observing the pumps, discharge line, and meters on Platform Elly. At various times that evening, a field operator checked equipment at Platform Elly, including the flow meters, shipping pumps, and the pipeline itself. The field operator visually checked the pipeline down to the point at which it entered the water. At 1903, having given the pipeline over an hour to settle, and having detected no leak on the platform, the nightshift controller restarted one shipping pump.

About 1915, the leak detection system issued a third leak alarm, again indicating a leak at Mile 0. The nightshift controller allowed the shipping pump to continue to operate to determine whether the leak detection system would normalize. When the leak alarm did not clear, the nightshift controller again shut down the pump at 1942.

After the third leak alarm, in addition to directing the field operator to continue checking for a leak on Platform Elly, the nightshift controller alerted the person-in-charge (on-duty supervisor) about the issues with the leak detection system. They agreed to call the pipeline superintendent, who was not on shift at the time, to request that the pipeline superintendent go to Beta Pump Station to assist in troubleshooting the leak alarms. The pipeline superintendent arrived at Beta Pump Station about 2000 and rebooted the leak detection system. Once the alarms had cleared, about 2029, the nightshift controller restarted the shipping pump.

About 2039, the leak detection system issued a fourth leak alarm, again indicating a leak at Mile 0. The nightshift controller shut down the shipping pump at 2043.

About 2112, the nightshift controller restarted a shipping pump to continue troubleshooting, and he switched from one flow meter to the other to evaluate whether the meter was causing the leak alarms.

At 2123, a fifth alarm activated, and the nightshift controller shut down the shipping pump 1 minute later, at 2124. Twenty minutes later, having discovered no issues with any meters or valves on Platform Elly, and with the leak alarms having cleared, the nightshift controller restarted the pump and resumed shipping.

A sixth alarm activated at 2201. The controller stopped the pump at 2233 and restarted it at 2315.

At 2330, a seventh leak alarm activated. The nightshift controller continued to run one pump so that the onshore and offshore crew could conduct a manual leak detection calculation. The nightshift controller and the pipeline superintendent conducted the manual leak detection test in 30-minute increments, taking flow meter readings from about 0020 to 0220 on October 2 at both Platform Elly and Beta Pump Station. Comparing the results of the readings, the manual leak detection revealed a difference of about 16-20 barrels per hour between what was shipped from Platform Elly and what was received at Beta Pump Station. The controller stopped the pump and shut down shipping at the end of the manual leak detection test.

At 0234, Beta employees called SoCal Ship Services, Beta's right-of-way patrol contractor, to perform a pipeline right-of-way inspection via the vessel *Nicholas L*, starting from shore and working toward Platform Elly. The right-of-way inspection, in which the vessel crew visually inspected the water above the pipeline's entire path for oil, began about 0330. It was before sunrise, and therefore the vessel crew conducted the inspection in the dark, using a spotlight at the front of the vessel and flashlights to look for oil; they also attempted to smell any oil on the surface. At 0510, the right-of-way patrol crew reported they had not found anything. After the report from the right-of-way inspection, the nightshift controller started a pump and resumed shipping at 0511.

At 0528, an eighth leak alarm activated. About 0550, the dayshift controller came back on duty and relieved the nightshift controller.

At 0604, the dayshift controller stopped shipping and called for a pipeline right-of-way survey in daylight. Sunrise was at 0647, and the vessel *Nicholas L* crew started inspecting the pipeline right-of-way for a second time about 0710, starting from Platform Elly and traveling toward shore. About 0809, the vessel crew reported that they saw a roughly 60-foot-wide-by-1.5-mile-long oil sheen on the water, located about 4.7 miles from the shoreline (see figure 1).

Figure 3 shows the timeline of leak alarms and the oil release discovery.

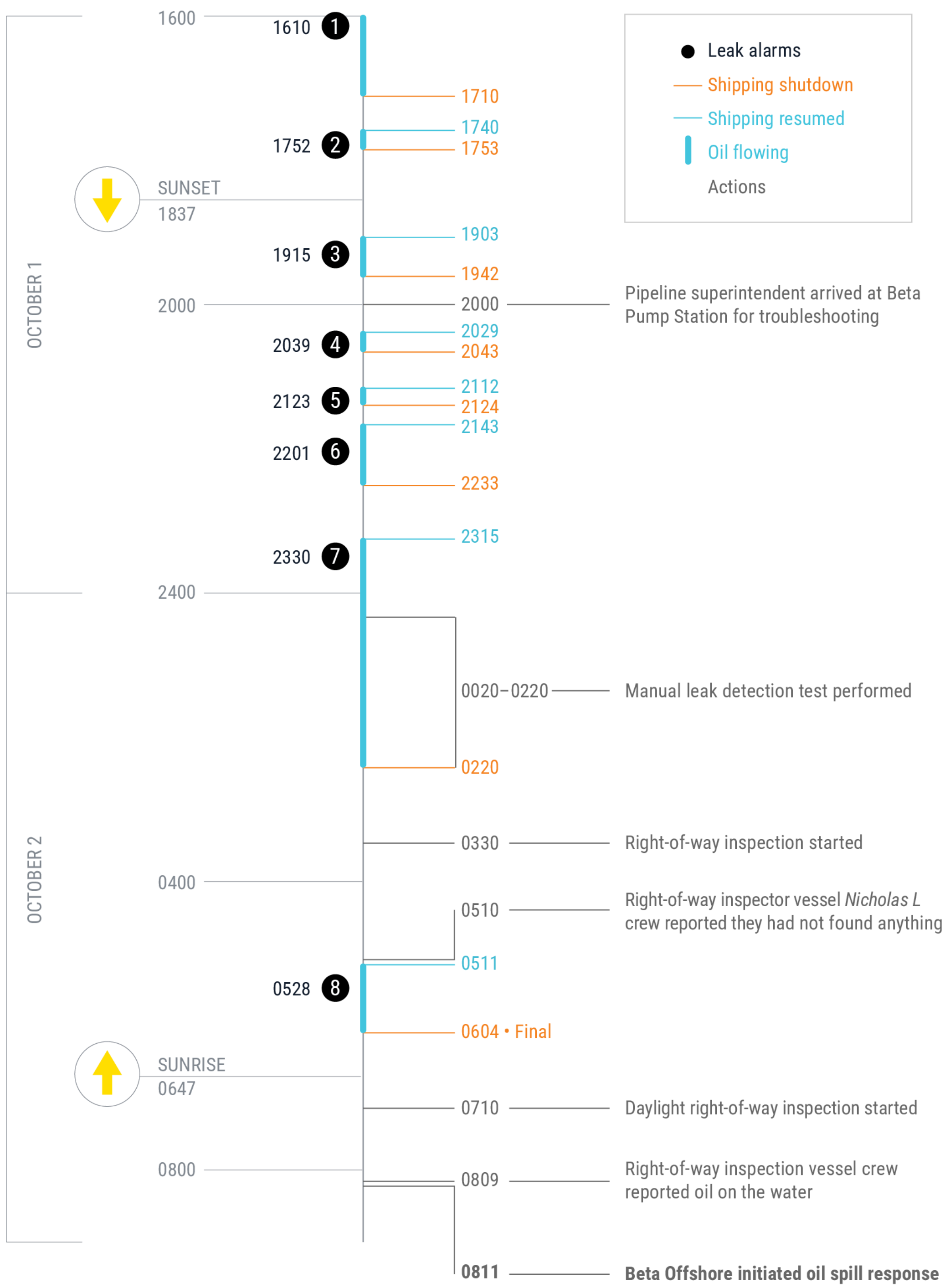

Figure 3. Timeline of leak alarms and oil release discovery.

1.1.2.3 Response to Oil Release

Once the right-of-way inspection vessel confirmed oil in the water, Beta initiated its oil spill response plan.[3] Notifications went out to the oil spill removal organizations: SoCal Ship Services and the Marine Spill Response Corporation. At 1002, while the San Pedro Bay Pipeline's valves were closed from the Platform Elly control room, the pipeline superintendent started the shipping pumps at Beta Pump Station to pull pressure off the pipeline. This process created a vacuum in the pipeline, which alleviated pressure at the oil release site and pulled any remaining product out of the pipeline along with sea water through the leak location to prevent any further crude oil from leaking into the ocean. Negative pressure was achieved before noon on October 2.

A unified command formed, consisting of Amplify and local, state, and federal agencies, including the Coast Guard, Bureau of Safety and Environmental Enforcement (BSEE), National Oceanic and Atmospheric Administration (NOAA), Pipeline and Hazardous Materials Safety Administration (PHMSA), California Department of Fish and Wildlife, and local law enforcement.[4]

1.1.2.4 Oil Release Detection from Other Sources

At 1813 on October 1, the crew of a vessel in San Pedro Bay discovered a sheen in the water 3 miles offshore. (The location of the sheen was about 2.2 miles east of the San Pedro Bay Pipeline oil release location.) At 1830, the vessel crew reported an "oil slick" to the Coast Guard's Vessel Traffic Service (VTS) Los Angeles-Long Beach (LA-LB) via VHF radio and shortly afterward also reported it to the Coast Guard sector command center. The Coast Guard directed the vessel crew to report the sheen to the National Response Center (NRC), which the vessel crew did.[5] The vessel crew reported to the NRC that the estimated size of the sheen was 2 miles long and 100 meters (328 feet) wide. At 1909, Coast Guard Sector LA-LB Incident Management Division personnel briefed the Federal On-Scene Coordinator's Representative, California Oil Spill Prevention and Response, and

[3] Beta maintained an oil spill response plan based on Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements.

[4] BSEE resides within the Department of the Interior.

[5] The *National Response Center* is a continuously staffed communications center that receives telephonic notification of all oil, chemical, radiological, biological, and etiological discharges into the environment, anywhere in the United States and its territories.

Orange County Sheriff Department/Harbor Patrol about the reported sheen.[6] The agencies determined that no assets were available to respond to the location of the reported pollution until the next morning due to Pacific Air Show support and safety concerns related to crew endurance and the capability of nighttime detection.

Separately, at 1858, the NOAA Environmental Satellite, Data, and Information Service satellite analysis branch observed a possible oil anomaly on satellite imagery in San Pedro Bay less than 3 miles from the San Pedro Bay Pipeline (see figure 4).[7] On October 2 at 0157, NOAA reported the oil anomaly to the NRC.[8] The NRC shared this information with BSEE. The NRC did not inform Beta of these reports, nor was it required to.

[6] A *Federal On-Scene Coordinator* is a designated representative who represents the federal government within a unified command.

[7] An *oil anomaly* looks out of place or unnatural based on experience, but there is no discernible source, no previously reported oil spill; the anomaly exhibits low contrast with its surroundings or is near natural phenomena.

[8] For significant spills, the Office of Response and Restoration (OR&R) is responsible for providing scientific support to the federal on-scene coordinator overseeing the response. OR&R provides situational awareness to the Unified Command. OR&R is provided on-scene and remote scientific support. NOAA’s National Weather Service provided weather briefings and decision support to the Unified Command. Weather conditions will change how the oil moves and where it might strand on beaches.

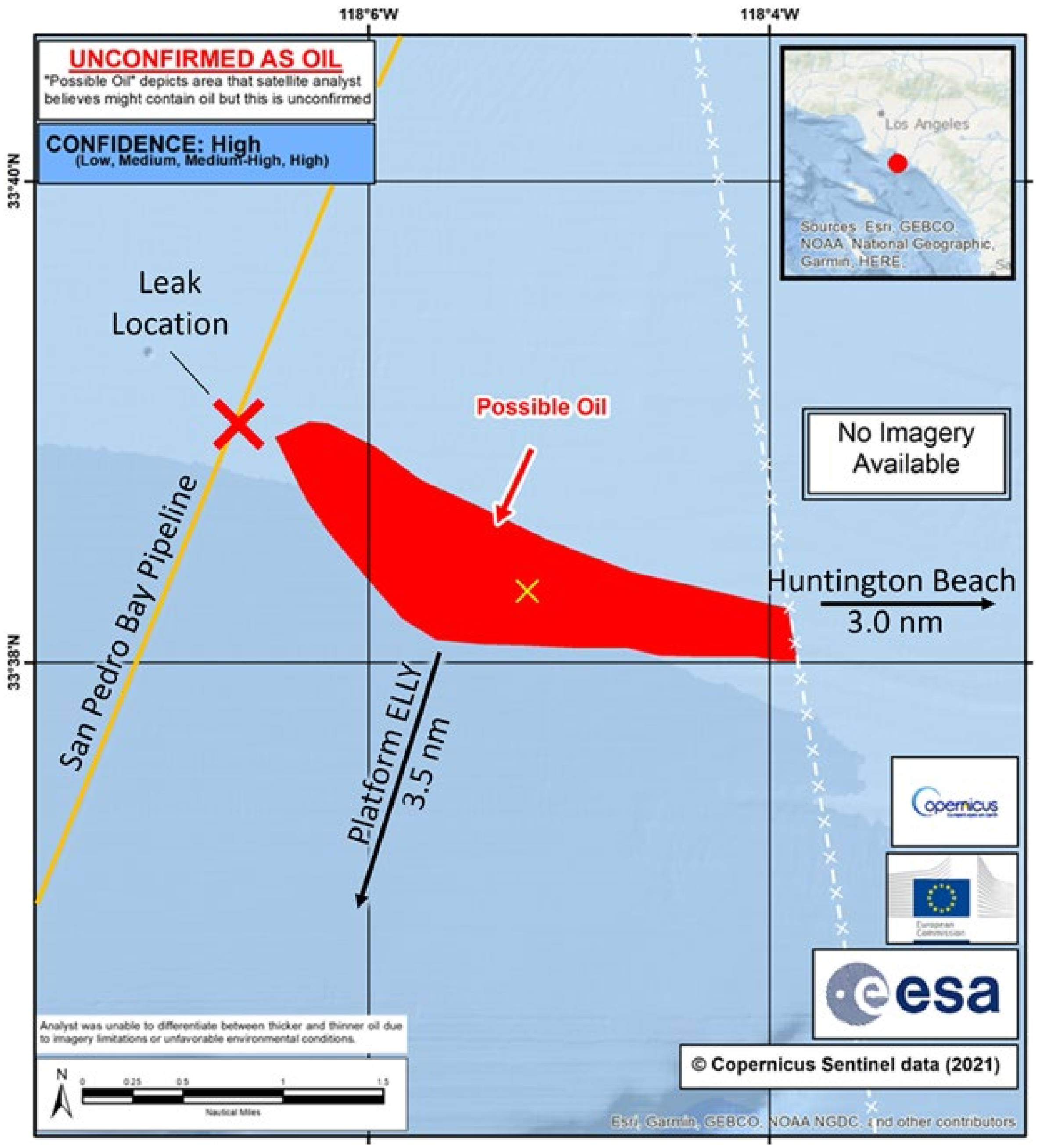

Figure 4. NOAA marine pollution surveillance report image from 1858 on October 1, 2021, showing the oil anomaly in red. The yellow *X*, indicating the center point of the potential oil slick, was less than 3 miles from the San Pedro Bay Pipeline. Pipeline location, leak location, and distances to Platform Elly and Huntington Beach added by the National Transportation Safety Board. (Background source: NOAA)

At 0730 on October 2, Coast Guard Incident Management Division personnel and the Orange County Sheriff's Harbor Patrol proceeded to the reported oil spill location to investigate. They discovered oil in the water about 0830, shortly after the Beta right-of-way patrol contractor visually confirmed the presence of oil.

Additionally, in the morning on October 2, in response to the NRC report, BSEE had two inspectors en route to the reported oil sheen location, one via helicopter and one on a vessel, when they were informed of the oil spill by Beta.

1.1.2.5 Pipeline Damage

Following the oil release and pipeline shutdown, Beta’s contractor completed a detailed underwater pipeline survey on October 22, 2021. The purpose of the survey was to identify and map any displacement of the pipeline and search for any indication of how the pipeline was damaged. The survey showed that a 4,025-foot section of pipeline was displaced, with a maximum displacement point 105 feet from the original pipeline location, and there was evidence of seabed scars/scouring adjacent to and near the damage (see figure 5). The pipeline’s concrete coating was also damaged. (In the most recent remotely operated vehicle [ROV] survey contracted by Beta, conducted in 2020, the pipeline was positioned in the original pipeline location.)

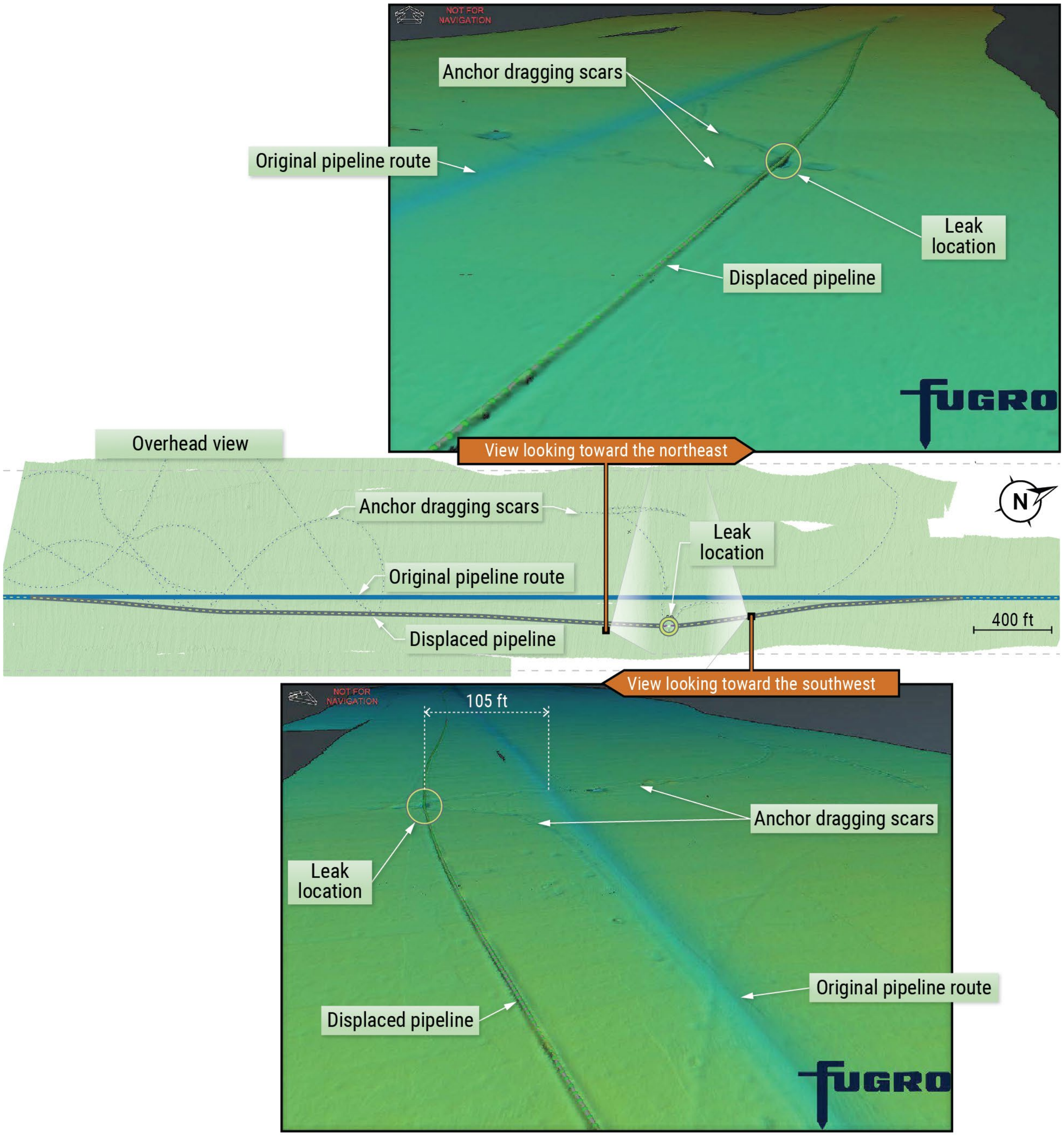

Figure 5. Results of the survey showing the San Pedro Bay Pipeline original location, leak location, pipeline displacement, and anchor dragging scars, viewed looking toward the northeast (*top*), from overhead (*middle*), and looking toward the southwest (*bottom*). (Background sources: Amplify, Aqueos, Fugro)

Crews conducted underwater nondestructive testing of the failed section of pipeline. The surveyors also found indications of a longitudinal crack with an overall measured length of 21⅜ inches on the outer surface. The circumferential profile showed the pipeline was out of round with a convex (dented) segment at the crack location. The crack was at the 10:30 through 11:00 o'clock position relative to the pipe facing north and below the weld seam (see figure 6).[9]

Figure 6. San Pedro Bay Pipeline underwater nondestructive testing showing a portion of the crack indication, highlighted in red, on the pipe on October 11, 2021. (Background source: Aqueos)

1.1.3 January 2021 – Anchor Dragging

1.1.3.1 Precasualty Events

The postcasualty ROV survey showed scarring on the sea floor along the length of the displaced section of pipeline that was consistent with anchor dragging. The Coast Guard and National Transportation Safety Board (NTSB) reviewed evidence to identify vessels that could have dragged anchor and damaged the pipeline. A May 2020 survey showed that the San Pedro Bay Pipeline was in its originally installed

[9] Clock positions are as viewed looking along the product flow direction with the 12 o'clock position located at the top of the pipe.

location and that no damage had occurred since a previous survey in 2018. Therefore, the Coast Guard and NTSB focused on the period between May 2020, when the last survey was conducted, and the time of the leak, reviewing automatic identification system (AIS) data for the area surrounding the damage location. The review identified only two vessels, the containerships *Beijing* and *MSC Danit*, that crossed the pipeline near the oil release location in a manner consistent with anchor dragging. Radar data and radio communications recorded by VTS LA-LB confirmed that both vessels had dragged anchor on January 25, 2021.[10]

Starting in late 2020 and extending through 2021, supply chain disruptions associated with the COVID-19 pandemic had led to unprecedented backups at the ports of Los Angeles and Long Beach, requiring containerships to anchor or drift at sea for up to 2 weeks while awaiting a berth. Throughout this period, the designated anchorage areas in San Pedro Bay, off the Los Angeles and Long Beach coast, were filled to capacity. (See section 1.6.2 for more information on anchorages.)

In the early morning on January 18, 2021, the 1,199-foot-long containership *MSC Danit* arrived in San Pedro Bay (see figure 7) and dropped its port anchor near the center of anchorage position SF-3, as assigned by VTS LA-LB. (See section 1.5 for more information about VTS.) After dropping the anchor, the crew payed out a total of seven shots (630 feet) of anchor chain to hold the vessel in the 93-foot-deep water. According to crewmembers, they placed the vessel's main propulsion engine on "standby," and the engineering control room remained staffed while at anchor.

[10] The NTSB also reviewed seismic data for the time period. No earthquakes occurred between May 2020 and October 2021 that were of sufficient magnitude to have caused damage to the pipeline or other structures.

Figure 7. Containership *MSC Danit* at anchor in San Pedro Bay, October 2021. (Source: Coast Guard)

The next day, on January 19, sustained winds in San Pedro Bay rose to between 22 and 35 knots, with gusts as high as 43 knots. The wind direction was from the northeast, coming off the shore. Peak significant wave heights were 5.2 feet (1.6 meters).[11] The northeast winds subsided that evening. Throughout the high-winds event, the *MSC Danit* remained anchored in position SF-3, with no indications of dragging anchor. Logs and records from VTS LA-LB showed no evidence of any vessels dragging anchor on January 19.

On January 23, the 1,150-foot-long containership *Beijing* arrived in San Pedro Bay and lowered its port anchor near the center of its assigned anchorage position SF-12, to the southwest of the *MSC Danit* (see figure 8, and see section 1.4 for additional vessel information). The crew then payed out 6 shots (540 feet) of anchor chain into the water. At the location where the *Beijing* anchored, the water depth was 102 feet.

[11] *Significant wave height* is the average height of the highest one-third waves in a wave spectrum. Significant wave height is the international standard sea height forecast reference.

Figure 8. Containership *Beijing* at anchor in San Pedro Bay, November 2021. (Source: Coast Guard)

The crew placed the *Beijing*'s engine in a 15-minute standby status while at anchor, according to the chief engineer. At night while at anchor, oilers stood watches and an engineering officer was on call if needed or in the event of an emergency.

SF-3 and SF-12 were circular anchorage positions with radii of 1,800 feet. SF-3 was located within the charted Anchorage F, while SF-12 was one of several Coast Guard designated "contingency" locations added southwest of Anchorage F (see figure 9). Immediately after the *MSC Danit* and *Beijing* arrived at their respective anchoring positions, the crews set up their electronic chart display and information systems (ECDISs) to alert them in the event of an anchor dragging. On each vessel, the officer of the watch input parameters into the system for a circle centered on the anchor drop position with a diameter about the length of the distance between the anchor and the vessel's GPS antenna (anchor chain length plus distance from the hawsepipe to the GPS antenna). If their respective vessel's position moved outside of the circle displayed on that ship's ECDIS, an audible alarm sounded.

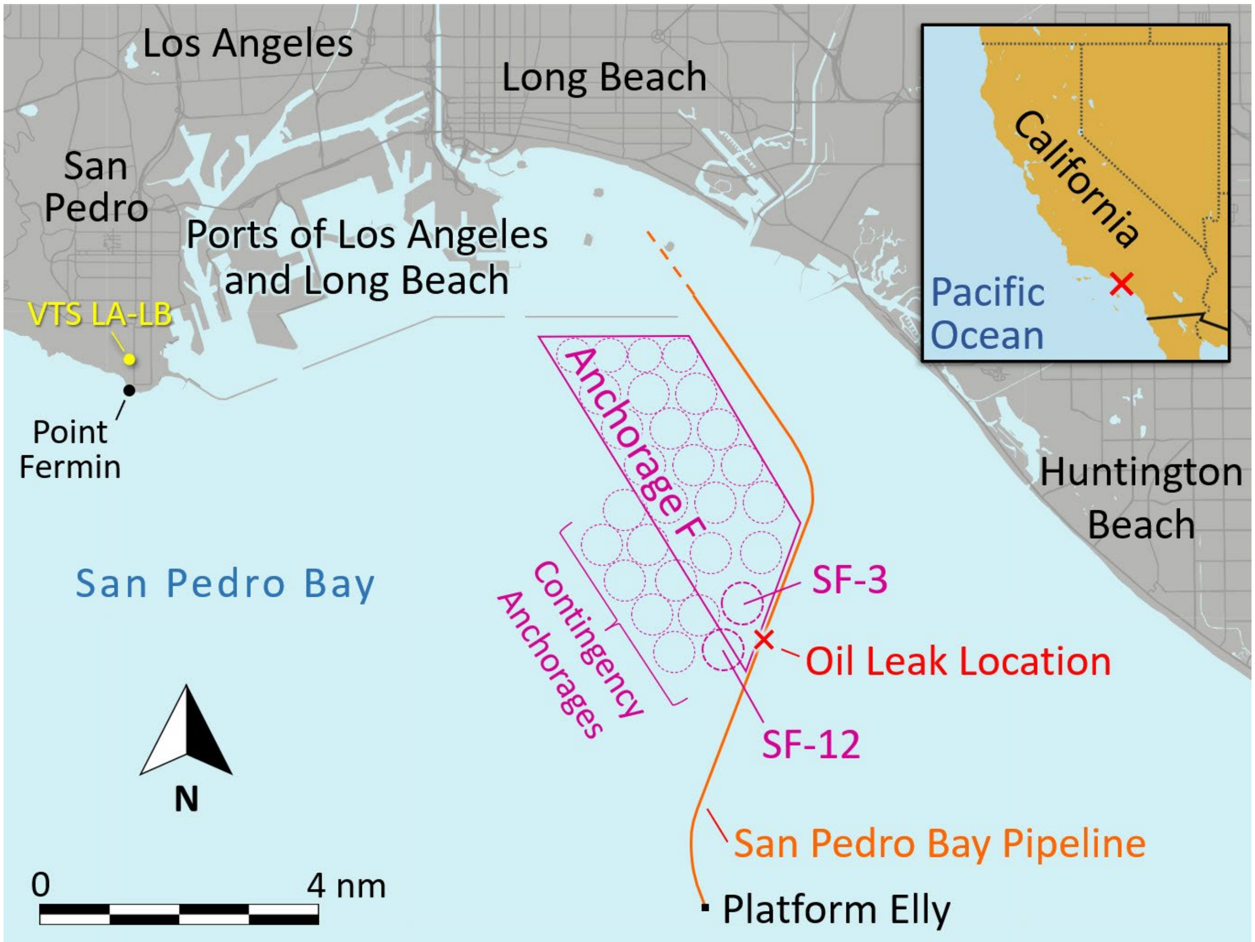

Figure 9. San Pedro Bay Pipeline, with locations of oil release, federal Anchorage F, and contingency anchorage positions near Anchorage F. Other anchorage areas and contingency anchorage positions in San Pedro Bay are not shown. (Background source: Google Maps)

A portion of the San Pedro Bay Pipeline ran parallel to the southeast boundary of Anchorage F; the distance between the anchorage and the pipeline's charted location was about 180 feet. At its closest point, the pipeline's charted position was 2,586 feet from the center and 786 feet from the outer edge of anchorage position SF-3. The pipeline's charted location was 2,733 feet from the center and 933 feet from the outer edge of anchorage position SF-12.

On January 23, the National Weather Service issued a gale watch for the area, and at 2100 on Sunday, January 24, the National Weather Service issued a gale warning that was in effect through the following Tuesday afternoon, January 26.[12] The forecast on January 24 predicted 20- to 30-knot winds from the west overnight with gusts to 40 knots. Sustained winds were expected to increase to 25–35 knots the next morning, becoming 30–40 knots by the afternoon.

At 0001 on January 25, anchored vessels occupied nearly all anchorage positions in Anchorage F and all contingency anchorage positions southwest of Anchorage F. The containership *CMA CGM Mexico* occupied contingency anchorage position SF-11, due west of the *Beijing*'s anchorage position, while the tanker *Hong Kong Spirit* occupied anchorage position SF-10, to the west of the *MSC Danit*'s position (see figure 10).

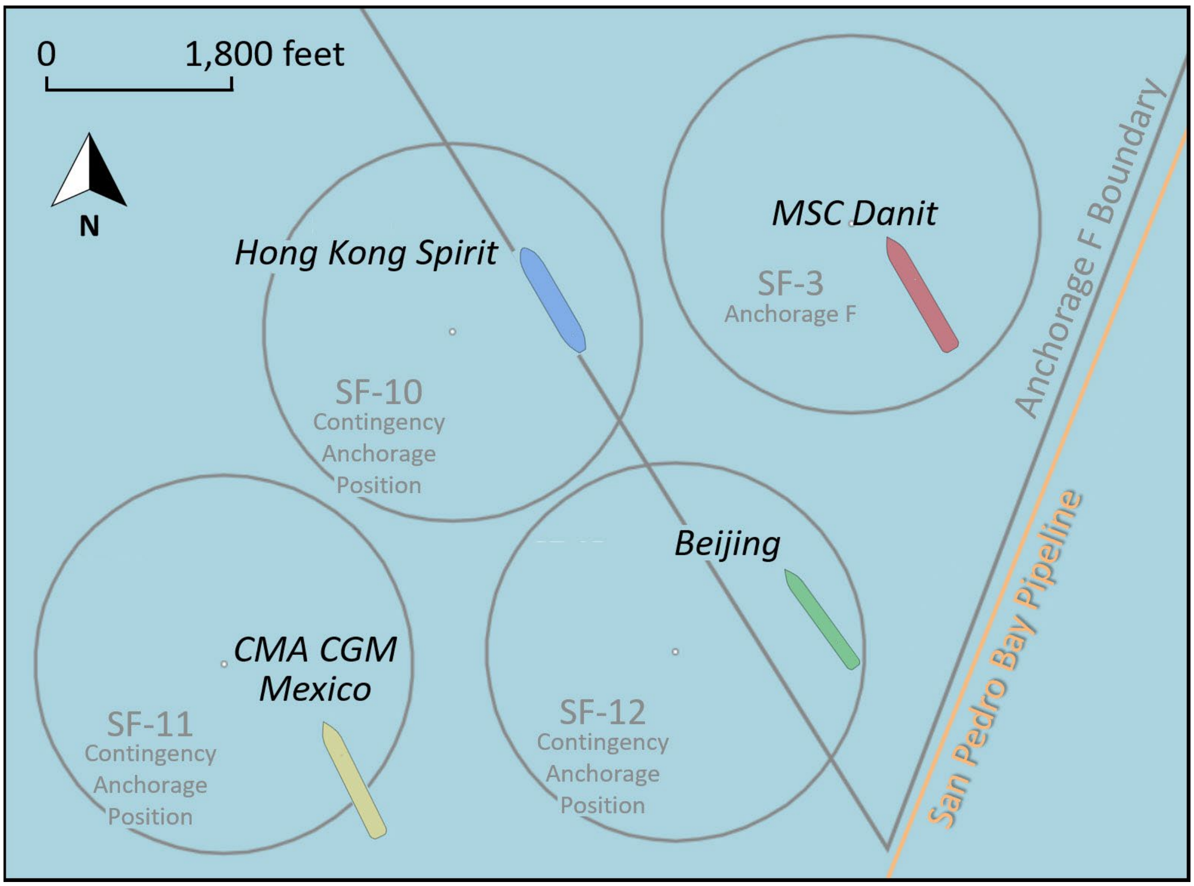

Figure 10. Anchorage AIS positions of *MSC Danit*, *Beijing*, and nearby vessels at 0001 on January 25, 2021.

[12] (a) A *gale watch* is a watch for an increased risk of a gale force wind event for sustained surface winds, or frequent gusts, of 34 knots (39 mph) to 47 knots (54 mph), but its occurrence, location, and/or timing is still uncertain. (b) A *gale warning* is a warning of sustained surface winds, or frequent gusts, in the range of 34 knots (39 mph) to 47 knots (54 mph) inclusive, either predicted or occurring, and not directly associated with a tropical cyclone.

At 0200, in anticipation of the forecasted increasing winds, VTS LA-LB began issuing hourly high-winds warnings via VHF radio to the vessels at anchor in San Pedro Bay. With each broadcast, the VTS watchstander advised vessels to have engines on immediate standby and a second anchor ready for letting go. As predicted, wind speeds began steadily increasing starting at 0230. At 0318, the NOAA weather station at the entrance to the Port of Los Angeles (Angel's Gate) recorded sustained winds from the northwest of 18 knots and a maximum gust of 29 knots.

VTS LA-LB watchstanders used a Kongsberg Norcontrol C-Scope maritime surveillance system to monitor vessels entering, exiting, and anchored within the service's area of responsibility. The system integrated radar and AIS data and displayed the information to allow watchstanders to keep track of vessels' locations. The configurable displays showed features such as anchorage areas and positions. The system was also capable of detecting and warning the VTS watchstander during potential anchor dragging situations. When an anchored vessel moved out of a designated anchor watch area, an audible and visual alarm was automatically triggered on the system.

The Kongsberg maritime surveillance system used by the watchstanders was also capable of displaying full nautical charts, which included charted hazards such as pipelines. However, the charts could be toggled on or off in the system by the operator, and, according to a VTS LA-LB representative, the standard practice was to have the full charts toggled off because the full chart display was too cluttered with information.

At 0324 on January 25, the VTS watchstander at the surveillance system console (the watch supervisor, who was the senior person on duty at VTS that day) began receiving multiple successive and sometimes overlapping anchor-dragging alarms for vessels in the San Pedro Bay anchorages. With each alarm, the watchstander contacted the associated vessel and advised the crew to check to ensure that the vessel was not dragging anchor.

At 0330, the wind speed at the VTS LA-LB facility in San Pedro, California, was observed to rise from 15 to 28 knots, with gusts up to 47 knots.

1.1.3.2 Containership *Beijing*

About 0350, the ECDIS anchor-dragging alarm sounded on the *Beijing* bridge. The second officer acknowledged the alarm and checked the containership's position, confirming that the vessel was dragging anchor about 0354. The second officer called the master and then called the engine control room, directing the oiler on watch to have the engineering department prepare the main engine for getting underway. He next called the chief officer, bosun, and duty ordinary seaman and told them to proceed to the bow.

The master went to the bridge, took the watch from the second officer, and ordered the second officer to go to the bow to prepare to heave up the anchor. The master also ordered the chief engineer to start the engine.

At 0356, the *Beijing*'s engine had not yet been started, but AIS data showed that the vessel started to move eastward out of SF-12 on a course over ground of about 70° and a speed over ground between 1.5 and 2.1 knots (see figure 11).[13] The vessel moved laterally, with its heading to the northwest. Four minutes later, wind speeds at the *Beijing*'s location reached Beaufort scale force 8 (34–40 knots), according to the vessel's deck log.[14]

[13] Vessel location data used throughout this report are as reported from each vessel's AIS. The AIS data for each vessel were consistent with radar data displayed on VTS LA-LB's Kongsberg maritime surveillance system and other evidence collected by the NTSB. Therefore, the AIS data were determined to be accurate.

[14] The *Beaufort wind scale* is a method for estimating wind strength without using instruments. The scale ranges from force 0 (winds less than 1 knot) to force 12 (hurricane: winds 64 knots or more). It is still used for its original purpose as well as for tying various components of weather (wind strength, sea state, and observable effects) into a unified picture.

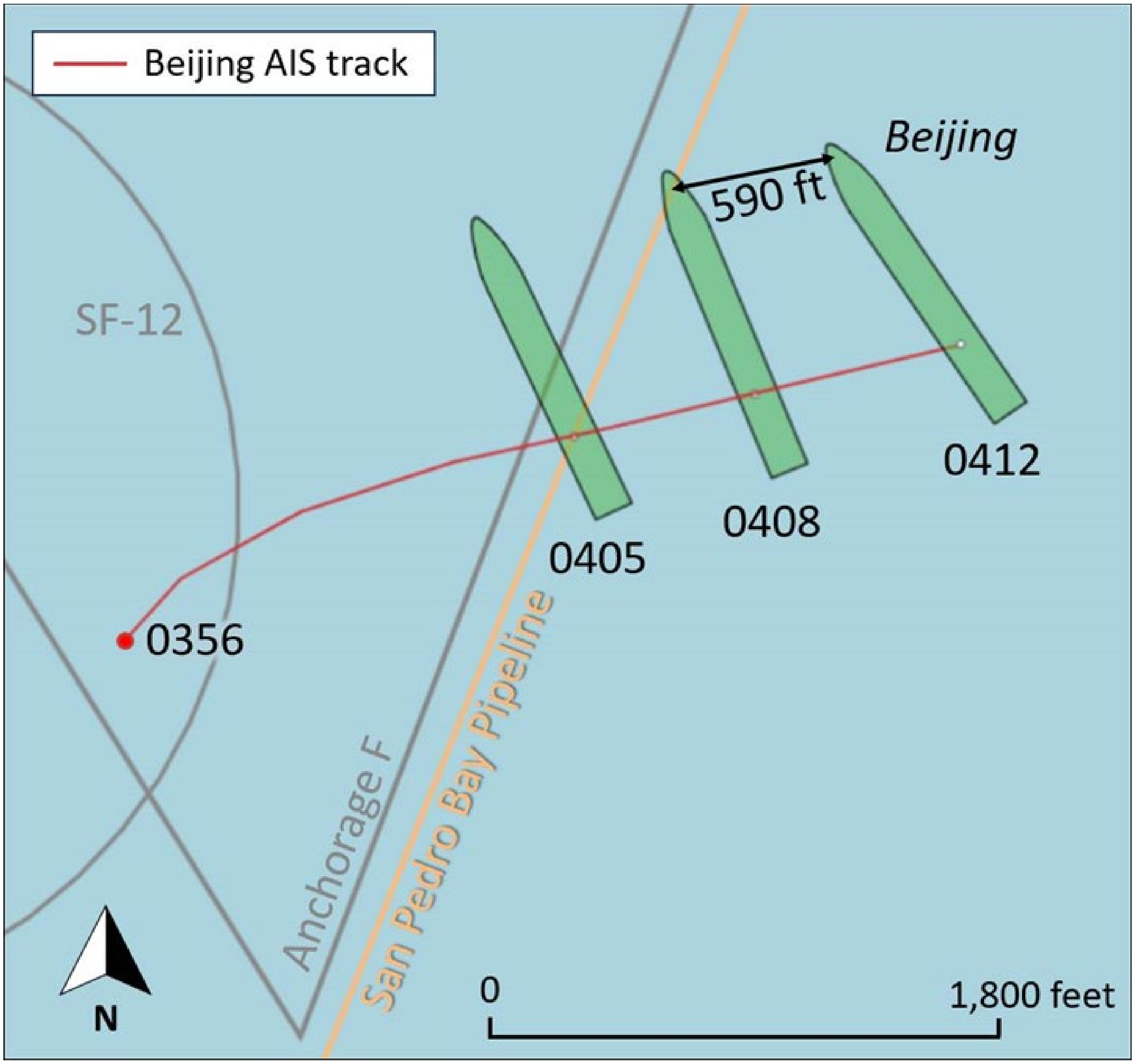

Figure 11. Initial AIS track of the *Beijing* as it moved out of anchorage position SF-12 and crossed the San Pedro Bay Pipeline on January 25, 2021. (See figure 12 for full track of the *Beijing* during anchor dragging.)

At 0403, the anchor-dragging alarm on the VTS LA-LB surveillance system sounded for the *Beijing*. The VTS watchstander contacted the *Beijing* via VHF radio. The master of the *Beijing* responded and confirmed that the vessel was dragging anchor. The master radioed that the *Beijing* was starting its engine and that it would attempt to heave up its anchor.

At 0405, the containership's AIS position passed over the charted location of the San Pedro Bay Pipeline (the *Beijing*'s AIS antenna was located 846 feet aft of its bow). At the same time, the crew on the exposed bow of the *Beijing* began heaving in the port anchor chain with the windlass. At 0410, the windlass stopped due to an electrical problem with the windlass motor, and the ship's electro-technical officer (ETO) was summoned to troubleshoot.

Meanwhile, the *Beijing*'s main propulsion engine had been started and, according to the master, the ship began maneuvering at 0411, "to avoid close quarter[s] with surrounding vessels and pipelines behind the ships." One minute later, the ship's eastward progress halted about 2,900 feet from where it had begun dragging anchor. At this moment, the *Beijing*'s bow, from which the port anchor chain extended, was 590 feet from where it had passed over the San Pedro Bay Pipeline's charted location.

With the ETO on hand at the bow, the *Beijing* crew restarted the anchor windlass multiple times. The crew heaved in more anchor chain each time until a relay in the electrical circuitry tripped, stopping the motor again. The ETO noted that the motor was overheating and drawing excess current.

While the *Beijing* crew was troubleshooting the port anchor windlass, VTS watchstanders were dealing with two other containerships in San Pedro Bay, the *CMA CGM New Jersey* and *Ever Front*, that collided when their anchors dragged. At the same time, additional anchor dragging alarms were sounding on the VTS LA-LB surveillance system, and other ships were reporting to VTS that their anchors were dragging and that they were getting underway. Alarms and reports of vessels getting underway continued throughout the morning.

About 0542, the *CMA CGM Mexico*, which had been anchored in position SF-11 to the west of the *Beijing*, began dragging anchor in an easterly direction. Within 9 minutes, the *CMA CGM Mexico* had drifted into anchorage position SF-12, where the *Beijing* had been anchored. The *CMA CGM Mexico* crew informed VTS LA-LB that they were heaving up the ship's anchor and would depart the anchorage to drift at sea.

The *Beijing* remained near the pipeline, using its engine and bow thruster to hold position. At 0606, the *Beijing* informed VTS LA-LB that the vessel had 1.5 shots (135 feet) of chain "on deck," the anchor windlass was overheating and was being repaired, and the vessel would be maintaining its current position.[15] The crew later

[15] *On deck* refers to the amount of chain deployed starting at the anchor windlass on the bow.

updated the report to VTS LA-LB, stating that there were 1.5 shots of chain “in the water.”[16]

While heaving in its anchor, the *CMA CGM Mexico* drifted farther east, and, at 0630, the vessel crew radioed the *Beijing*, requesting that its crew maneuver the *Beijing* to provide more space, using astern propulsion if necessary. The *Beijing* crew responded that they would “adjust our engine to give you more distance.” Twenty-one minutes later, at 0651, the *CMA CGM Mexico* reported to VTS LA-LB that it was underway and heading south. At 0652, the vessel exited anchorage position SF-12.

The *Beijing* ETO eventually determined that the port anchor windlass motor was burned out, and he informed the bridge at 0700. After consultation with a shoreside electrical superintendent, the crew was directed to swap the motor on the port anchor windlass with the motor on the starboard anchor windlass. Work began immediately. According to the master’s statement, the anchor remained in the water with 1.5 shots (135 feet) of chain, similar to the report to VTS LA-LB; the second officer recalled that 5 shots (450 feet) of chain was on deck, based on markings on the chain that he witnessed while on the bow.

After the *Beijing* had initially passed over the pipeline, it continued to maneuver nearby, with its AIS position passing over the charted location of the pipeline at least 10 times (see figure 12). During this time, the vessel’s AIS position was as much as 1,044 feet to the east and 1,158 feet to the west of its last pipeline crossing.

[16] *In the water* refers to the amount of chain deployed starting where the chain enters the water.

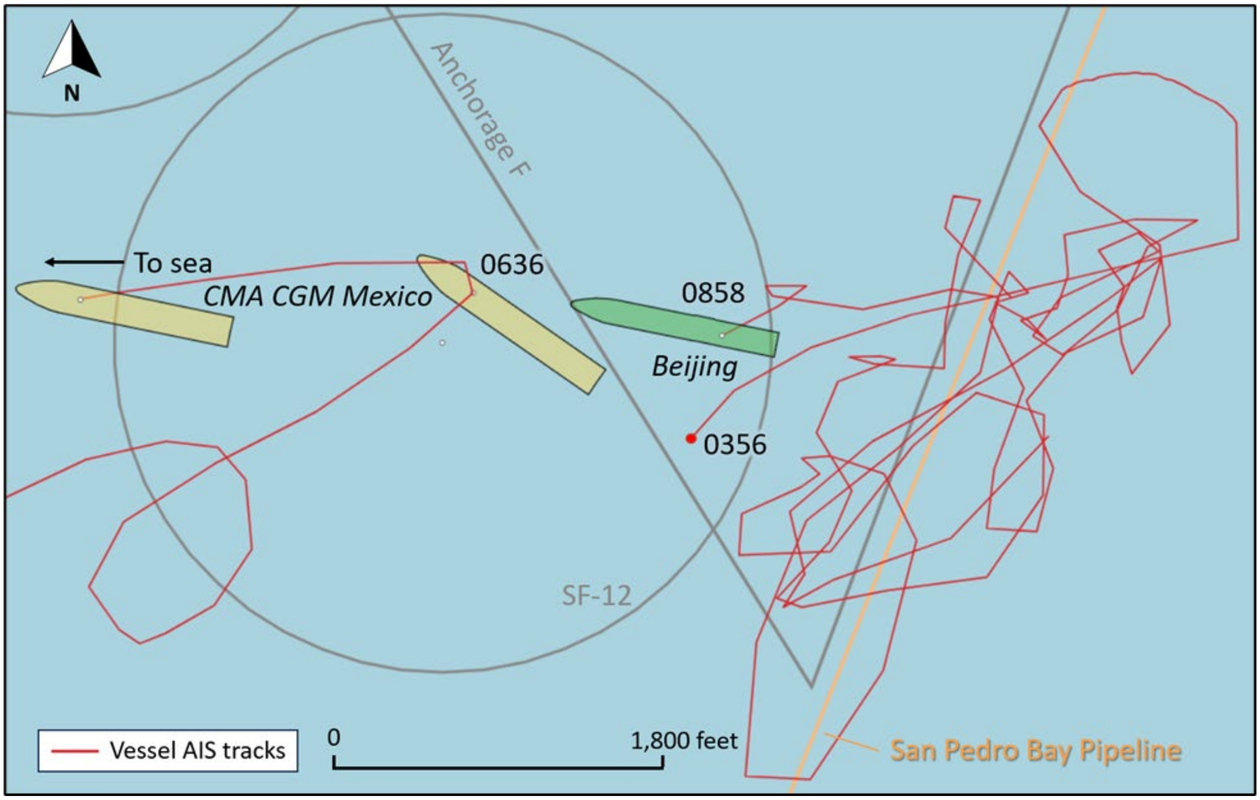

Figure 12. AIS track of the *Beijing* between 0356 and 0858 on January 25, 2021. Also shown is the AIS track of the *CMA CGM Mexico* as it dragged anchor into contingency anchorage position SF-12 between 0551 and 0652 on the same morning.

About 0900, the *Beijing* reentered SF-12 and did not approach the pipeline again.

According to crew accounts, the work switching out the windlass motors took 10–12 hours to complete. The ship did not heave in the anchor fully until about midnight on January 26. The *Beijing* then proceeded to a position offshore where it could safely drift until the weather subsided.

After the anchor dragging, the *Beijing*'s operating company conducted an internal investigation into the failure of the port windlass. The investigation determined that the failure of the windlass motor was likely due to the attempt to heave in the anchor in "sudden bad weather prevailing conditions." The facts of the incident were later circulated and shared with crews throughout the operator's fleet.

1.1.3.3 Containership *MSC Danit*

The January 25, 2021, 0400 deck log entry for the *MSC Danit* noted that the vessel's anchorage position, which was consistent with the vessel's AIS data, was well within its assigned anchorage SF-3. The vessel's deck log reported winds at the time were from the northwest at Beaufort scale force 7 (27–33 knots).

AIS data showed that, about 0516, the *MSC Danit* began moving in a generally eastward direction while swinging to the south and then back to the north (see figure 13). The ship's headings were westerly. The crew started the ship's main propulsion engine and, at 0523, shifted control of the engine to the bridge. Over the next 39 minutes, the bridge team issued engine orders alternating between dead slow ahead (27 rpm) and stop.

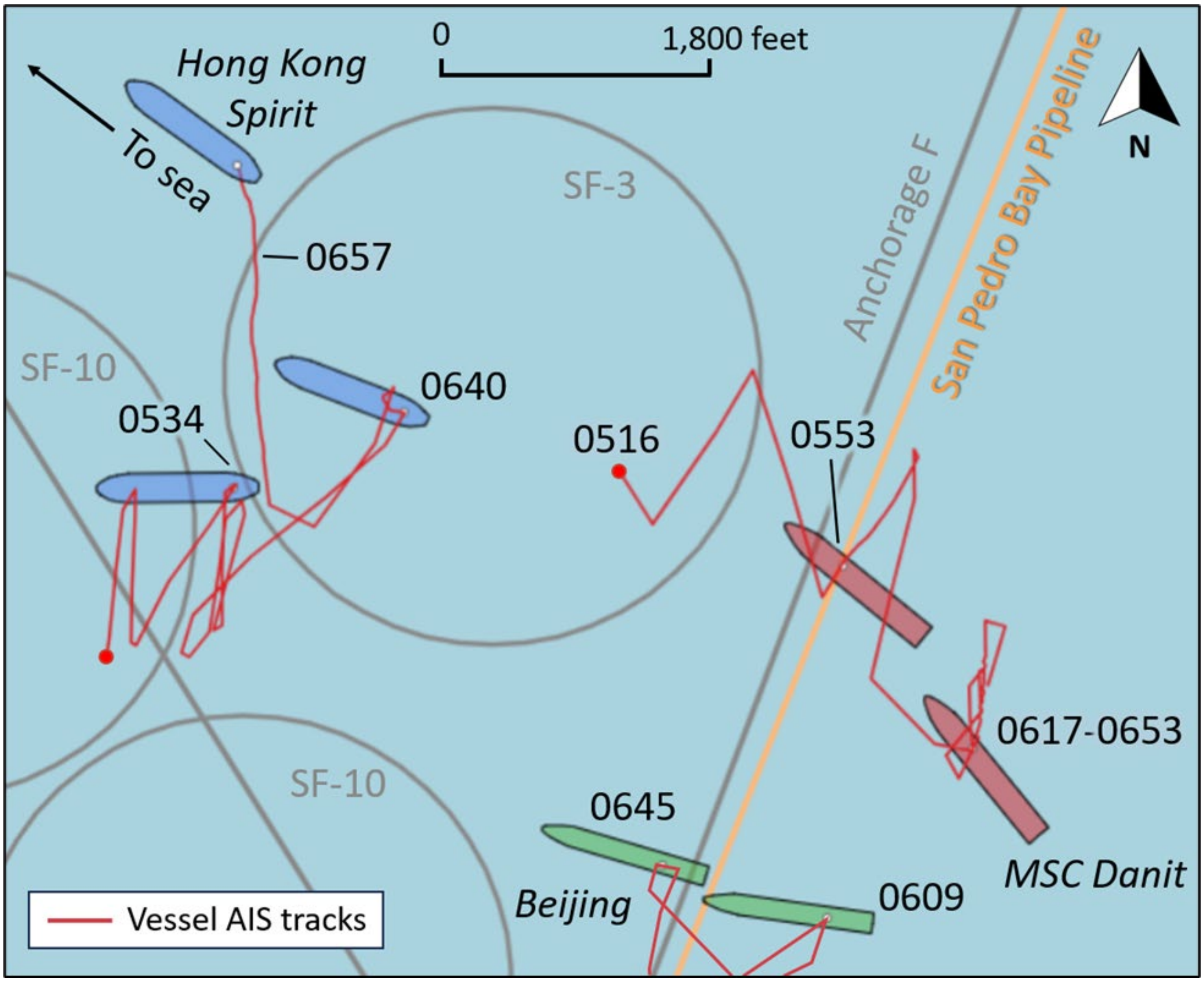

Figure 13. Initial AIS track of the *MSC Danit* as it moved out of anchorage position SF-3 and crossed the charted location of the San Pedro Bay Pipeline. Also shown is the AIS track of the *Hong Kong Spirit* as it dragged anchor into the *MSC Danit*'s assigned anchorage, and the AIS track of the *Beijing* as it dragged anchor off the port side of the *MSC Danit*, during the same period. (See figure 14 for remaining track of *MSC Danit* during anchor dragging.)

At 0526, an alarm sounded on VTS LA-LB's Kongsberg maritime surveillance system, indicating that the *MSC Danit* was dragging anchor. The VTS watchstander radioed the containership, requesting that the vessel confirm that it was not dragging anchor, that its propulsion engine was on immediate standby, and that a second anchor was ready for letting go. Deck watchstanders on the *MSC Danit* responded that the engine was on standby and a second anchor was ready for letting go, but the vessel's anchor was "not dragging for the moment."

AIS data showed the *MSC Danit* continued to move to the east, and, between 0534 and 0540, the vessel's AIS position passed outside the boundary of anchorage SF-3, with the vessel on a westerly heading. At 0549, a watchstander on the *MSC Danit* radioed VTS LA-LB to report that the vessel was no longer holding position, that the main propulsion engine was in use, and that the ship was starting to heave in its anchor. The watchstander further reported that the *MSC Danit* would be proceeding out of the anchorage to the south to drift. According to the ship's bell book, the crew began heaving in the anchor a minute later.

Between 0535 and 0602, the containership continued to move in an easterly direction, with a westerly heading, alternating movement in the northeast and southeast directions. At 0553, the vessel's AIS position, moving to the northeast, passed over the charted location of the San Pedro Bay Pipeline.

About the same time that the *MSC Danit* had begun dragging anchor, AIS data showed that the tanker *Hong Kong Spirit*, which had been anchored in contingency position SF-10, to the west of the *MSC Danit*, had also begun dragging anchor in an easterly direction. About 0535, the stern on the *Hong Kong Spirit* crossed into the western edge of SF-3 (see figure 13 above). The tanker then moved to the southwest, out of SF-3, before drifting back again into the *MSC Danit*'s assigned anchorage position at 0617.

At 0617, the *MSC Danit*'s eastward movement stopped, with the ship's bow about 842 feet southeast of the location where the leak in the San Pedro Bay Pipeline would eventually be found. Over the next 36 minutes, the vessel moved along a north/south axis but did not move appreciably to the east or west. The containership's heading remained westerly during this time, varying between 255° and 325°.

At 0620, VTS LA-LB radioed the *MSC Danit* to inform the vessel about the *Beijing*'s anchor windlass problem, noting that the *Beijing* would be maintaining its current position. The *MSC Danit* acknowledged this information and informed VTS LA-LB that it would stop heaving up its anchor. The *MSC Danit* crew further informed VTS LA-LB that their vessel was "coming in [a] dangerous situation" with the

Hong Kong Spirit. The *MSC Danit* watchstander radioed, "I will try to keep this position for the moment, until situation clear." According to a cadet assigned to the vessel at the time, the master had ordered two additional shots of anchor chain payed out in order to avoid a collision with the *Hong Kong Spirit*.

At 0635, VTS LA-LB contacted the *MSC Danit*, asking that the vessel crew confirm that it would be able to "keep an appropriate sea space between yourself and the *Beijing*." The *MSC Danit* crew responded that the vessel would come astern to open the distance between the vessels.

At 0654, the *Hong Kong Spirit* crew reported to VTS LA-LB that the vessel was underway. The vessel began maneuvering to the northwest, away from the *MSC Danit*. One minute later, the *MSC Danit* crew contacted VTS LA-LB to report that it was continuing to heave up its anchor. About the same time, the *MSC Danit* began moving forward, to the west, toward the pipeline. The *Hong Kong Spirit* exited anchorage position SF-3 at 0657.

At 0703, the *MSC Danit*'s forward progress halted, with the ship directly over the pipeline (see figure 14). For the next 1 hour and 8 minutes, the ship's AIS position remained within an area about 600 feet in radius, centered on the eventual leak location on the pipeline.

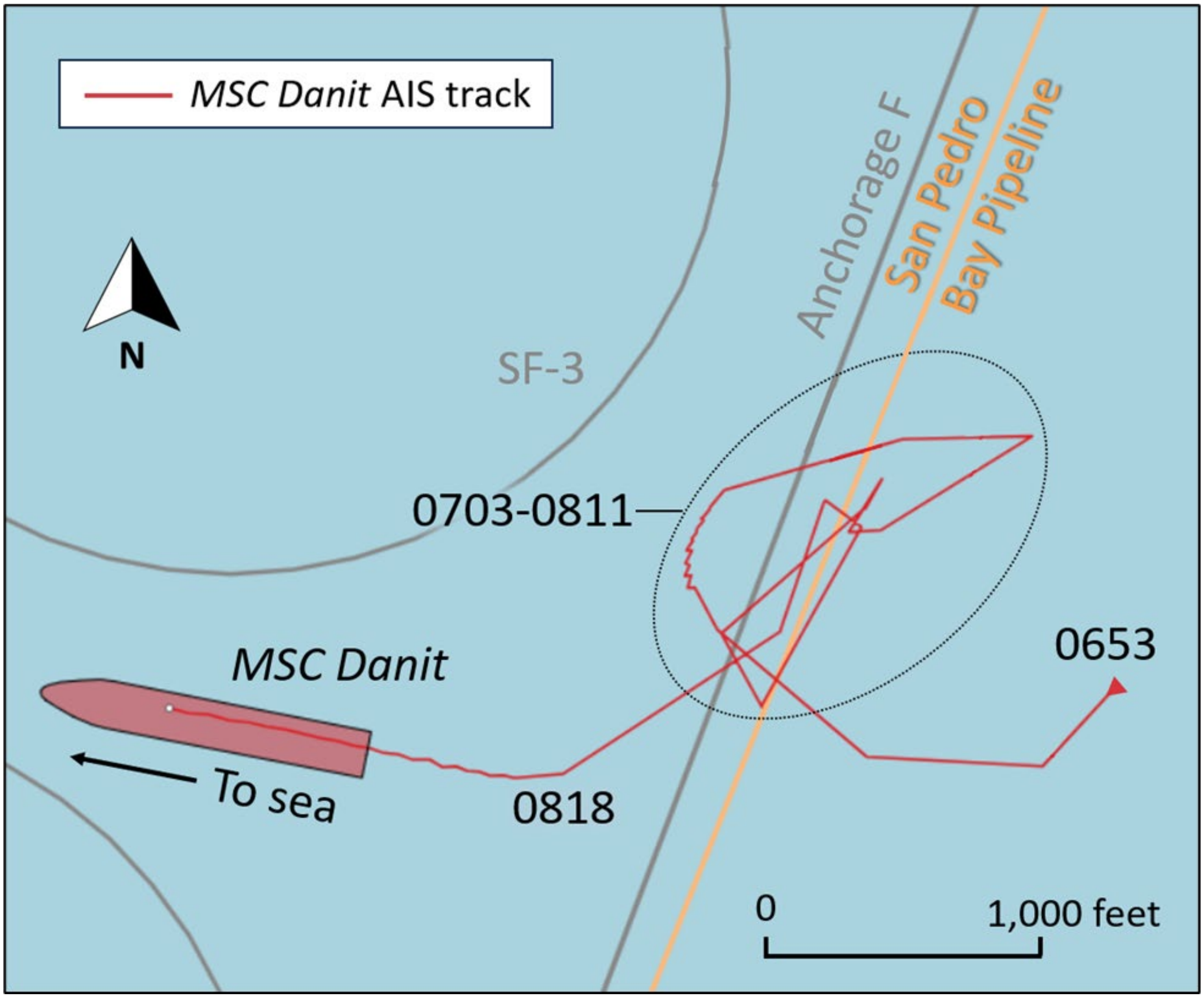

Figure 14. AIS track of the *MSC Danit* between 0653 and 0818.

After 0811, the *MSC Danit* began moving to the west again on a heading of 280° and at a speed of 2.5 knots. The ship's crew reported "anchor aweigh" to VTS LA-LB at 0816 and logged "anchor up" in the bell book at 0820. The *MSC Danit*'s speed increased, and the vessel departed San Pedro Bay. At 1100, the ship began drifting in open water. The ship drifted until a berth became available in Long Beach on January 27.

Between the start of the high-winds event and 0930 on January 25, 19 vessels, including the *MSC Danit*, departed the San Pedro Bay anchorages due to the weather conditions.

1.1.3.4 Vessel Damage

The *Beijing* experienced a failure of the port anchor windlass motor, which the operating company attributed to the attempt to heave in the anchor in heavy weather conditions. There was no damage reported by the *MSC Danit* related to the anchor dragging.

1.2 Injuries

There were no injuries reported among pipeline crew as a result of the oil release on October 1–2. There were no injuries reported on the *Beijing* or *MSC Danit* related to the anchor dragging on January 25.

1.3 Pipeline Information

1.3.1 Overview

The San Pedro Bay Pipeline, a 16-inch-diameter, interstate transmission, common carrier pipeline, transported about 4,000 barrels per day of heavy crude oil about 17.3 miles from Platform Elly to the Beta Pump Station located ashore at the Port of Long Beach, California (see figure 2).[17] The crude oil was pumped from oil wells located near Platforms Ellen and Eureka, where drilling rigs on each platform have been in operation since the 1980s. Oil, water, and associated natural gas were pumped through production wells from subsurface petroleum reservoirs and transferred via production pipelines to Platform Elly, where the water and products were separated. Crude oil was dewatered and sent to shore. Platform Elly pumped the crude oil through the San Pedro Bay Pipeline to the Beta Pump Station. During normal operations, the pipeline flowed south to north.

The San Pedro Bay Pipeline began at the 16-inch mainline valve located on Platform Elly and transitioned from aboveground to subsea piping. The first 10.9 miles of the pipeline laid on top of the ocean floor. The remainder of the offshore pipeline was buried 10–15 feet below the ocean floor until it reached the shoreline. The pipeline then continued onshore, where it was buried 5–15 feet below grade for about 2.2 miles to the Beta Pump Station.

[17] (a) *Pump stations* are industrial facilities that maintain the flow and pressure of the crude oil by receiving oil from the San Pedro Bay Pipeline. Due to the friction loss created by liquids moving through the length of the pipeline, the pipes are subject to pressure losses over the length of the piping. Pump stations bolster (re-pressurize) the pipeline for further delivery to reach its customers. (b) An *interstate pipeline* is a pipeline or that part of a pipeline that is used in transportation of hazardous liquids in interstate or foreign commerce. An interstate pipeline is a pipeline that extends beyond the boundaries of one state.

1.3.2 Pipeline Design and Construction

The Shell Oil Company designed the San Pedro Bay Pipeline. The US Army Corps of Engineers issued the original permit to construct the pipeline on December 11, 1979. When the pipeline was built, the Corps of Engineers permit specified that the pipeline was to be placed at least 500 yards (1,500 feet) outside of Anchorage F.[18] About 15.28 miles of the pipeline were designed to be offshore, with 6.37 miles in federal waters and 8.91 miles in State waters.

Kaiser manufactured the pipe in 1979, and the pipeline was constructed from 1979 through 1980. The entire offshore pipeline, from Platform Elly to the shoreline, was successfully hydrostatically tested at 2,160 pounds per square inch gauge (psig) for 24 hours following construction and before being placed into operation.[19]

The pipeline had a maximum operating pressure of 1,152 psig, and the shipping pumps automatically shut down on high pressure at 1,045 psig. The total oil volume in the pipeline was 20,228 barrels.

The San Pedro Bay Pipeline was fabricated from 16-inch-external-diameter, 0.375-inch to -0.844-inch-wall-thickness, American Petroleum Institute-5L Grade B to -X-52-grade steel pipe with a specified minimum yield strength of 35,000 to 52,000 psi, depending on the locations of the section of pipe. Where the beginning of the line started at the riser on Platform Elly, there was a 16-inch-diameter seamless steel pipe with 0.844-inch wall thickness. The remainder of the offshore portion was constructed of 16-inch-diameter double submerged arc welded steel pipe with a 0.500-inch wall thickness, with plain-end field-welded pipe joints.[20] The external coating consisted of two coats of fully plasticized coal tar enamel and glass reinforcement covered with an outer wrap of 15-pound felt. A concrete weight coating, consisting of 1-inch-thick, 190-pound-per-cubic-foot concrete, was applied over the external coat before installation.

[18] Anchorage F was later expanded. See section 1.6.2 for more information.

[19] *Hydrostatic testing* refers to the process of testing pipelines to examine their strength using water or another medium. Hydrostatic testing also can identify and locate leaks, which can weaken the vessel's strength. Pressure tests are used by pipeline operators to determine the integrity of the pipeline immediately after construction and before placing the pipeline in service, as well as during a pipeline's operating life. The postconstruction pressure test verifies the adequacy of the pipeline materials and construction methods.

[20] *Double submerged arc welding* is a process that involves two submerged arc welding passes. One pass of submerged arc welding takes place on one side of the material, and another pass takes place on the opposite.

Before the accident, the San Pedro Bay Pipeline had no history of leaks.

1.4 Vessel Information

1.4.1 *Beijing*

The 1,150-foot-long, 140-foot-wide containership *Beijing* was built in 2006 by Hyundai Heavy Industries Co. Ltd. in Ulsan, Korea. The 109,149-gross-ton (ITC) vessel had a single 101,640-hp (75,793-kW) MAN B&W main propulsion engine directly coupled to a fixed-pitch propeller; it was also fitted with a 3,353-hp (2,500-kW) tunnel bow thruster.[21] The containership had a cargo capacity of 9,469 20-foot-equivalent units (TEUs).

The *Beijing* was classified by DNV. Capetanissa Maritime Corporation, based in Monrovia, Liberia, owned the Malta-flagged vessel, and Costamare Shipping Company, SA, based in Piraeus, Greece, was the commercial manager. V.Ships Greece Ltd., also located in Piraeus, was the operator and provided technical management.

The *Beijing* was fitted with two 16.5-ton high-holding-power anchors, each connected to 14 shots (1,260 feet) of chain. Two anchor windlasses, one on the port bow and one on the starboard bow, serviced the anchors. The Rolls-Royce windlasses were rated for a maximum speed of 9 meters of anchor chain per minute (29.5 feet/minute). Less than 1 month before the January 25, 2021, anchor dragging, an electrical insulation resistance test was performed on the windlass motors, with no anomalies reported. On January 10, 2021, the crew performed a semi-annual inspection of the windlasses. The inspection report noted that the windlasses were in "serviceable" condition both before and after the inspection. Deck and engineering crew stated in interviews that the port windlass had not presented a problem before the anchor dragging.

1.4.2 *MSC Danit*

The 1,199-foot-long, 168-foot-wide containership *MSC Danit* was built in 2009 by Daewoo Shipbuilding & Marine Engineering Co. Ltd. in Geoje Island, Korea. The 153,092-gross-ton (ITC) vessel had a single 61,031-hp (45,511-kW) MAN B&W main propulsion engine directly coupled to a fixed-pitch propeller; it was also fitted with

[21] *GT ITC*, or gross tonnage-international tonnage convention, is the international standard for the measurement of the volume of all enclosed spaces on a vessel, as defined in the International Convention on Tonnage Measurement of Ships, 1969.

two 2,682-hp (2,000-kW) tunnel bow thrusters. The containership had a cargo capacity of 14,028 TEUs.

The *MSC Danit* was classified by DNV. Dordellas Finance Corp, based in Panama City, Panama, owned the Panama-flagged vessel, and MSC Mediterranean Shipping Company S.A., headquartered in Geneva, Switzerland, was the operator. Mediterranean Shipping Company s.r.l., a subsidiary of MSC Mediterranean Shipping Company S.A., based in Piano di Sorrento, Italy, provided technical management for the vessel.

The *MSC Danit* was fitted with two 21.5-ton high-holding-power anchors, each connected to 14 shots (1,260 feet) of chain. Two anchor windlasses, one on the port bow and one on the starboard bow, serviced the anchors. According to a master of the *MSC Danit* who was interviewed by investigators (but not aboard the vessel on January 25, 2021), the Rolls-Royce windlasses could heave in anchor chain at a rate of one shot every 5 minutes (18 feet/minute).

The table below shows vessel particulars for the *Beijing* and *MSC Danit*.

Table. Vessel Particulars

Vessel	*Beijing*	*MSC Danit*
Type	Cargo, General (Containership)	Cargo, General (Containership)
Owner/Operator	Capetanissa Maritime Corporation (Commercial)/V.Ships Greece Ltd. (Commercial)	Dordellas Finance Corp (Commercial)/MSC Mediterranean Shipping Company S.A. (Commercial)
Flag	Malta	Panama
Port of registry	Valetta, Malta	Panama City, Panama
Year built	2006	2009
Official number (US)	N/A	N/A
IMO number	9308508	9404649
Classification society	DNV	DNV
Length	1,150.1 ft (350.6 m)	1,199.0 ft (365.5 m)
Breadth (max.)	140.4 ft (42.8 m)	168.0 ft (51.2 m)
Draft	42.7 ft (13.0 m)	52.5 ft (16.0 m)
Tonnage	109,149 GT ITC	153,092 GT ITC
Engine power; manufacturer	1 x 101,640 hp (75,793 kW); MAN-B&W	1 x 61,031 hp (45,511 kW); MAN-B&W
Persons on board	22	20

1.5 Vessel Traffic Service Los Angeles-Long Beach Information

The purpose of a VTS is to provide active monitoring and navigation advice for vessels in confined and busy waterways. It is also designed to expedite ship movements, increase transportation system efficiency, and improve all-weather operating capability (US Coast Guard 2023, MAREX 2023a). VTS LA-LB assists in the safe navigation of vessels approaching the ports of Los Angeles and Long Beach. The service's area of responsibility extends from Point Fermin (located just west of the ports) out to 25 miles. VTS LA-LB is jointly operated by the Coast Guard and the Marine Exchange of Southern California (MAREX) under a public-private partnership from a vessel traffic center located in San Pedro, California.[22] The VTS LA-LB watch team consisted of three personnel: a civilian watch supervisor employed by MAREX, a second MAREX civilian, and a uniformed Coast Guard servicemember. (See section 1.9 for more information about VTS personnel.)

VTS LA-LB was responsible for assigning vessels to anchorages outside the breakwater for the Los Angeles and Long Beach ports. According to VTS operating procedures, the controller on watch assigned positions based on a vessel's draft, length, and type; the destination port (Los Angeles or Long Beach); emergency situations; and whether the Coast Guard expected to board the vessel. After assigning an anchorage, the controller was responsible for ensuring that the vessel anchored in the assigned position. Once the vessel was anchored, the controller monitored the vessel's position to ensure that it was not dragging anchor.

According to the operating procedures, when winds were forecasted or observed at 35 knots or greater, including gusts, the controller was required to notify the on-call senior manager for MAREX and the Coast Guard Sector LA-LB Command Center and ensure that anchored vessels had their propulsion plants in immediate standby and had a second anchor ready for letting go (VTS personnel followed these procedures during the heavy weather on January 25).

1.6 Waterway Information

1.6.1 San Pedro Bay

San Pedro Bay is a roughly 150-square-mile area bounded to the north and east by the cities of Huntington Beach, Seal Beach, Long Beach, and Los Angeles, California. Santa Catalina Island lies 15 miles southwest of the bay, across the San Pedro Channel. To the northwest and south, San Pedro Bay is open to the Pacific Ocean. A breakwater divides the bay, providing shelter for the ports of Los Angeles and Long Beach.

1.6.2 Anchorages

Title 33 *Code of Federal Regulations* (*CFR*) 110.214 defines the boundaries of nine federal anchorage areas for the ports of Los Angeles and Long Beach. Two of

[22] The MAREX is a nongovernment, nonprofit organization "dedicated to the development and efficient flow of maritime commerce throughout the region…The Marine Exchange maintains a continuous 24-hour service, and uses a state-of-the-art, comprehensive, computerized database system to provide vital statistics and information on ships calling at the four major ports in Southern California: Port Hueneme, Los Angeles, Long Beach, and San Diego; and the marine oil terminal at El Segundo" (MAREX 2023).

the anchorage areas lie outside the ports' breakwaters: Anchorage G and Anchorage F. As previously noted, VTS LA-LB was responsible for assigning ships to these outer anchorages. According to regulations, vessels were prohibited from anchoring outside of the designated anchorage areas without prior approval of the Coast Guard Captain of the Port, except for emergency reasons.

Anchorage F in San Pedro Bay was established in 1980, about the same time that the San Pedro Bay Pipeline was being constructed. The anchorage's original boundaries were defined in the *CFR* such that only the southeast corner of the area was close to the San Pedro Bay Pipeline (see figure 15).[23] The outer boundary of the closest anchorage position within Anchorage F, position F-16, was 2,430 feet from the pipeline.

In 2004, the Coast Guard announced in a Notice of Proposed Rulemaking a proposed expansion of Anchorage F that would move the southeastern boundary to its current location parallel to and about 180 feet from the San Pedro Bay Pipeline's pre-damage location. The Coast Guard stated that the proposed expansion was needed to "accommodate vessels of increasing size."[24]

As part of the analysis for the proposed expansion, the Coast Guard considered *Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply*, and determined that the change in anchorage boundaries was "not likely to have a significant adverse effect on the supply, distribution, or use of energy." The Coast Guard also analyzed the proposed expansion for compliance with the National Environmental Policy Act of 1969 (Title 42 *United States Code* 4321–4370f) and concluded that the expanded anchorage would not have a significant effect on the human environment.

In its announcement of the proposed enlargement of the anchorage, the Coast Guard invited public comments and requests for a public hearing. In December 2004, following the release of the Notice of Proposed Rulemaking, the Coast Guard briefed the Los Angeles-Long Beach Harbor Safety Committee on the proposed expansion of Anchorage F, and the call for public comments. Representatives from the Army Corps of Engineers, the California Department of Fish and Wildlife Office of Spill Prevention and Response, environmental groups, tanker operators, and the Ports of Los Angeles and Long Beach were present at the Harbor Safety Committee meeting.

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[23] *Federal Register*, Volume 45, May 8, 1980, page 30,431.

[24] *Federal Register*, Volume 69, November 5, 2004, page 64,549.

The Coast Guard received no comments or requests for a public hearing on the proposed expansion, and as a result they made no changes to the proposed expansion. The expansion went into effect in February 2006.[25] The Coast Guard added anchorage positions SF-1, SF-2, and SF-3 to the expanded anchorage area, with the outer edge of SF-3 at 786 feet from the pipeline's charted location (see figure 15). The Coast Guard briefed the Harbor Safety Committee in 2006 on the expansion going into effect and the establishment of the anchorage positions.

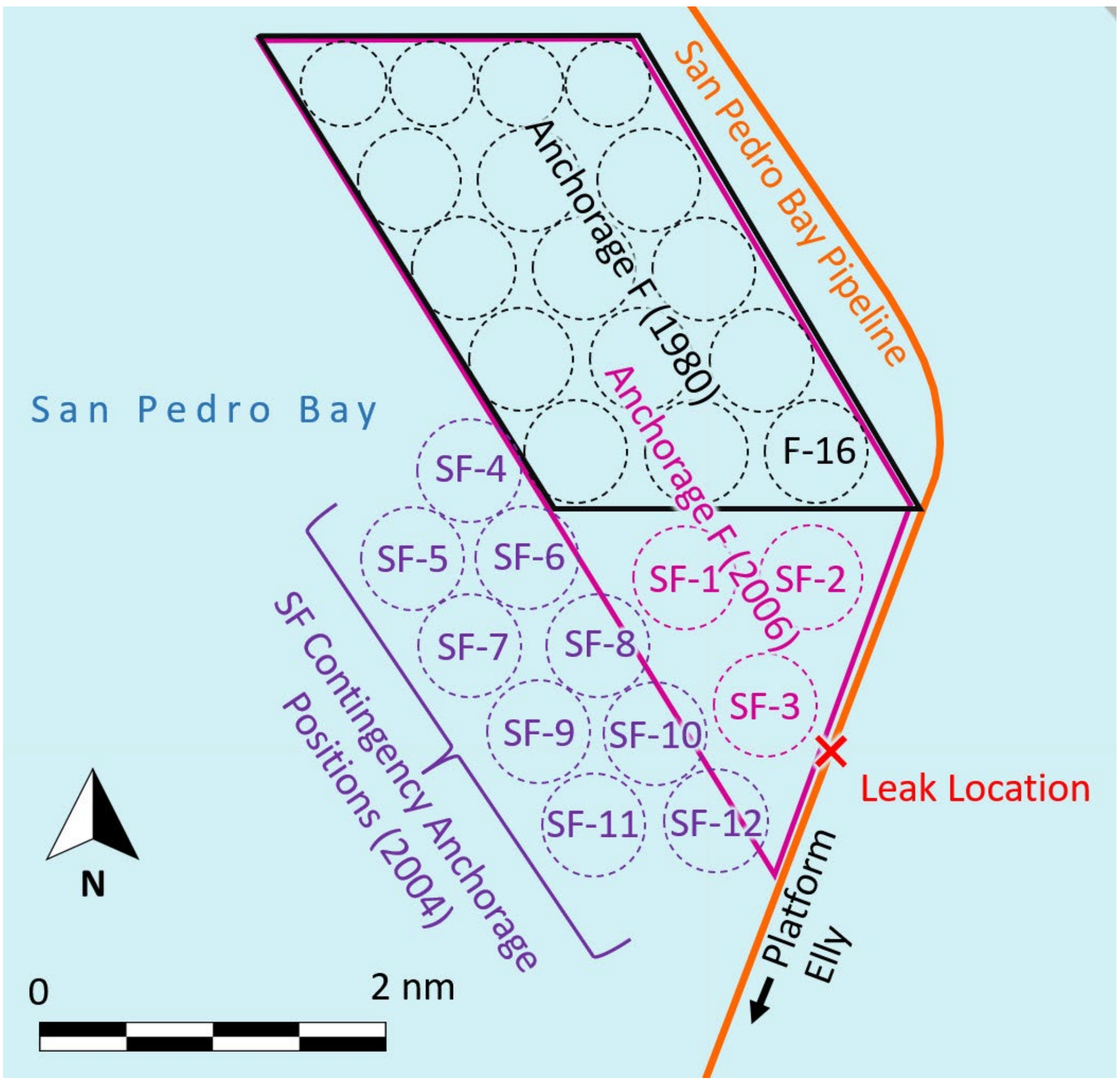

Figure 15. Boundaries of Anchorage F, as originally drawn in 1980 (in black) and as revised in 2006 (in magenta). Also shown are nine contingency anchorage positions established in 2004 (in purple). (Other contingency anchorages in San Pedro Bay are not shown.) (Background source: Google Maps)

[25] *Federal Register*, Volume 71, January 19, 2006, page 3,001.

In addition to the anchorage positions within the regulated anchorage areas, the Coast Guard established 23 contingency anchorage positions in San Pedro Bay to be used "when a suitable federal anchorage is not available or in an emergency situation" (US Coast Guard 2020). Contingency anchorage positions were originally established in 2002, and the locations of the positions were revised in 2004. Anchorage position SF-12, to which the *Beijing* was assigned on January 25, 2021, was a contingency anchorage. The outer edge of SF-12 was 933 feet from the charted location of the pipeline (see figure 9). The contingency anchorage positions were not defined in the *CFR* and were not included on navigation charts.

1.6.3 Nautical Charts

In US waters, mariners navigate using charts produced with data from the NOAA Office of Coast Survey. Charts may be in paper or electronic form, although recently the agency has begun phasing out the production of paper charts. Electronic navigation charts are displayed using a vessel's ECDIS system. Data for features on a nautical chart are collected from numerous sources. For pipelines, the pipeline owner provides data to NOAA at the completion of construction as a requirement for the Army Corps of Engineers permit. The data for the pipeline remain unchanged on charts, unless NOAA is informed that a change has taken place.

The San Pedro Bay Pipeline was charted on the NOAA nautical charts of the San Pedro Channel. The charts identify submarine pipelines and cables with specific symbols. A chart notice states:

> CAUTION SUBMARINE PIPELINES AND CABLES. . . Additional uncharted submarine pipelines and submarine cables may exist within the area of this chart. Not all submarine pipelines and submarine cables are required to be buried, and those that were originally buried may have become exposed. Mariners should use extreme caution when operating vessels in depths of water comparable to their draft in areas where pipelines and cables may exist, and when anchoring, dragging, or trawling.

A survey conducted in June 2022 showed that, at the southern corner of Anchorage F, the pipeline's actual location was about 96.5 feet closer to the anchorage area than the location shown on the nautical charts.

1.7 Environmental Conditions

1.7.1 January 2021

The high winds that began about 0230 on January 25, 2021, and continued through the afternoon of January 26 were the result of a strong cold front that moved through the area from the northwest to the southeast overnight between January 24 and 25. At 0530 on January 25, sustained winds of 26.4 knots and wind gusts of 36.9 knots were recorded at the NOAA Angel's Gate weather station, located 8 miles north-northwest of the anchorages. Gusts above 30 knots and sustained winds above 20 knots were recorded throughout the day. The wind direction was from the west-northwest, ranging between 276° and 304°.

Between midnight and 0300 on January 25, significant wave heights in San Pedro Bay averaged 5.7 feet (1.7 meters) as measured at the San Pedro South Waverider Buoy (station no. 46253). Significant wave heights increased upon the onset of the high winds, and, at 0556, the buoy recorded a significant wave height of 11.1 feet (3.4 meters). Three hours later, the significant wave heights reached a peak of 15.1 feet (4.6 meters).

1.7.2 October 2021

Between 1600 on October 1 and 0800 on October 2, the period during which the San Pedro Bay Pipeline's leak alarms activated, the skies along the Southern California coast were clear with 8–10 miles of visibility. Winds were light, ranging between 0 and 9 knots from the northwest. The air temperature at 1600 on October 1 was 71°F; the temperature dropped overnight, reaching a low of 62°F at 0700 on October 2. Significant wave heights in San Pedro Bay ranged from 2.6 to 3.3 feet, with water temperatures ranging between 68°F and 70°F.

1.8 Pipeline Operations

The San Pedro Bay Pipeline was monitored and controlled by a supervisory control and data acquisition (SCADA) system. The SCADA system allowed the pipeline controller to monitor pipe pressures and crude oil flow rate from one point to another along the pipeline. The system also allowed the pipeline controller to manipulate the remotely controlled pipeline valves, monitor leak detection of the line, review safety-related conditions, monitor and act on alarms, and receive reports of detected anomalies to the controls.

The control room was located offshore on Platform Elly, where a pipeline controller monitored and controlled crude oil movements. The pipeline controller could also remotely control the automated mainline motor-operated valve and close the emergency shut down mainline valves located at the Beta Pump Station. The Platform Elly control room operated 24 hours per day, 7 days a week. In addition, the pipeline could be monitored from an onshore control room at the Beta Pump Station. At the Beta Pump Station, the oil was metered and distributed through two onshore delivery pipelines. The pump station was staffed 7 days a week, 12 hours per day by a pipeline technician, and was otherwise remotely monitored.

1.8.1 Alarms

Alarms indicate an equipment malfunction, process deviation, or other condition that requires a controller's response. Some alarms are designated "safety-related" because they relate to an operational factor that is necessary to maintain pipeline integrity or could lead to the recognition of a condition that could impact the integrity of the pipeline or a developing abnormal or emergency situation. Amplify designated alarms designed to protect the public, property, or the environment as safety-related.

Beta's control room management procedure required review of safety-related alarm operations using a process that ensured alarms were accurate and supported safe pipeline operations. This procedure required monthly identification, recording, review, and analysis of false alarms.[26]

Beta controllers were trained on alarm management procedures. According to Beta's control room management procedure, controllers were trained on responding to abnormal operating conditions likely to occur simultaneously or in sequence. Controller training is discussed in more detail in Section 1.8.8.

1.8.2 Controller Experience with False Alarms

The nightshift controller who was on duty when many of the leak alarms sounded told the NTSB that before the oil release, he had experienced false leak alarms on the San Pedro Bay Pipeline. The dayshift controller told the NTSB that, when the leak alarm activated at 1610 on October 1, he assumed he had received false indications from the equipment. He told investigators that he was "thinking that it was just a regular loss of communication," and, "It didn't really dawn on me that it was actually a leak because it happens to us all the time."

[26] A *false alarm* is any alarm that was presented to the controller that did not accurately reflect the actual parameter or condition, or an alarm that misled a controller to believe a condition existed that did not exist.

1.8.3 Leak Detection

The San Pedro Bay Pipeline's SCADA system monitored the leak detection system. The leak detection system received data from the SCADA system and processed it through an algorithm. If the algorithm and subsequent pattern recognition test indicated a leak, the leak detection system would signal a leak alarm to the SCADA system.

The leak detection system used a volumetric comparison that occurred in two ways to detect leaks and limit the amount of crude oil spilled in the event of a leak.[27] When the system detected an abnormally low pressure, all crude oil shipping pumps would automatically stop in less than 5 seconds. The leak detection system also repeatedly scanned the meters at each end of the pipeline. A scan would calculate the volume of crude oil that had entered the pipeline, the change in crude oil volume in the shore surge tank due to level changes, the volume shipped to Beta Pump Station, and the pressure and temperature changes since the last scan. The leak detection system would then calculate a net volume imbalance for the system. If a leak occurred, the cumulative imbalance would grow steadily larger. Alarms would activate if volume balance discrepancies varied beyond specific short-term and long-term limits. If an alarm limit was exceeded, the system assumed there was a leak.

When a leak was detected, the system activated an audible and visual alarm, printed a report summarizing pipeline conditions, and generated a cumulative imbalance-versus-time trend plot for the last 200 scans.

The leak detection system showed the leak location in miles from Platform Elly to shore. According to Beta's Oil Spill Prevention and Response Plan, which PHMSA approved on March 22, 2021, "as a general rule … the location error decreases exponentially as the leak size increases. Leak location estimation depends on the quality of the measurements. For large leaks (greater than 20% of flow), an accuracy of [plus or minus] 5% of the distance from nearest two pressure meters is achievable." The San Pedro Bay Pipeline had two pressure meters, one on each end of the pipeline, that were roughly 17 miles apart. The system used a proprietary algorithm based on the pressure readings to determine leak location.

Once a potential leak was detected, the leak detection system analyzed pipeline pressures and crude oil flow rates to characterize the potential leak. The software identified a percentage of variation in flow and pressure shown as lambdas. The lambdas provided controllers with a quick indication of a potential leak on the

[27] A very large leak would be detected by a high/low pressure sensor (switch) on the pipeline from Platform Elly.

pipeline system. As long as the potential leak condition was present, the lambda value would remain high.

1.8.4 Communication between Platform Elly and Beta Pump Station

SCADA systems can be affected by environmental conditions such as fog, wind, or other inclement weather causing momentary communication loss. The instrument data inputs used by the SCADA system were sent between Platform Elly and Beta Pump Station through a microwave transmission system. If signal lapses from the instruments were long enough or absent, a communication-loss alarm would be triggered.

In 2020, Beta invested in a series of replacements and upgrades to the communications systems, to reduce the frequency of periodic alarms indicating lost communications between Platform Elly and Beta Pump Station. But according to interviews with the dayshift controller, nightshift controller, and the pipeline superintendent, controllers sometimes still experienced communication losses. Pipeline controllers received communication-loss alarms throughout the day on October 1.

Beta had a manual leak detection procedure that was available for use in the event of a communication breakdown between Platform Elly and the Beta Pump Station as a backup to the leak detection system. The manual leak detection criteria were to be based upon a 5% variance between the volume of crude oil flowing out of Platform Elly and the volume flowing into Beta Pump Station over a 1-hour period or a 1.5% variance over 24 hours.

1.8.5 Emergency Shutdown and Abnormal Operating Conditions

Beta's procedure titled "SPBPL 16 [inch] Emergency Shutdown, Isolation and Drawdown" directed in bold red letters that if a pipeline leak is suspected and/or indicated by the leak detection system, "shut down [the] 16 [inch] pipeline." Specifically, the pipeline was to be isolated by closing shutdown valves at three locations. After initial isolation, according to Beta's procedure, additional valves were to be closed, and an evaluation was to be performed to determine if drawdown of the pipeline was needed.

1.8.6 Pipeline Integrity Management

Integrity management is a process that identifies, assesses, and manages pipeline risks. All pipelines are required to have integrity management programs in high consequence areas (HCAs).[28] Beta had an integrity management plan that identified risk in HCAs and those that could affect an HCA. (The entire San Pedro Bay Pipeline falls within an HCA.) The integrity management program included the integration of information from in-line inspection, pressure testing, ROV, and other technologies. The assessment methods for pipeline integrity include ROV, right-of-way inspections, and in-line inspection tools.

1.8.7 Pipeline Damage Prevention

The San Pedro Bay Pipeline operator was required to have and carry out a written damage prevention program, and Beta had a damage prevention procedure as part of its Operations and Maintenance Manual. The manual included the following guidance:

> Whenever the Company discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time (as soon as possible). However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the Company may not operate the affected part of the system until it has corrected the unsafe condition.

1.8.8 Operator Qualification

According to 49 *CFR* Part 195, Subpart G, Qualification of Pipeline Personnel, to be qualified, an individual must have been evaluated and be able to perform specific tasks and recognize and react to abnormal operating conditions. Amplify's Operator Qualification Program required its controllers to be qualified for several tasks, including:

- Field Operations of a Pipeline, Including Startup/Shutdown
- Control Center Operations of a Pipeline, Including Startup/Shutdown
- Computational Pipeline Monitoring Leak Detection

Amplify required a written test and performance evaluation for qualification and a reevaluation period of 3 years for each task. At the time of the accident, the controllers and pipeline superintendent were qualified for Field Operations of a Pipeline, Including Startup/Shutdown and Control Center Operations of a Pipeline,

[28]A *high consequence area* means a waterway where a substantial likelihood of commercial navigation exists and is an unusually sensitive area, an ecological resource as defined in 49 *CFR* 195.450, and an ecologically unusually sensitive area as defined in Part 195.6.

Including Startup/Shutdown. They were not qualified for Computational Pipeline Monitoring Leak Detection. Amplify explained that Beta employees did not specifically train on Computational Pipeline Monitoring Leak Detection because the training was not relevant to controllers who operated the leak detection system in the control room. Computational Pipeline Monitoring Leak Detection was a training program for maintaining the underlying software that powered the leak detection system.

Amplify required its controllers to complete additional operator qualification modules on topics including abnormal operating conditions, control room management, and fatigue. At the time of the accident, the controllers were current on abnormal operating conditions training but not control room management or fatigue.

The required training for the task Control Center Operations of a Pipeline, Including Startup/Shutdown identified abnormal operating conditions, including a leak; piping, valve, or component failure; and unexplained pressure deviation. The abnormal operating condition training materials defined abnormal operating conditions, described how to recognize and react to them, and demonstrated the difference between an abnormal operating condition and abnormal operation.

1.8.9 Pipeline Safety Management Systems

A pipeline safety management system (PSMS) is a systematic approach to managing safety. PSMS enhances the effectiveness of risk management and enables continuous improvement of pipeline safety performance. PSMS has been evolving since 2012, when the NTSB issued safety recommendation P-12-17, calling on the American Petroleum Institute (API) to:

> Facilitate the development of a safety management system standard specific to the pipeline industry that is similar in scope to your Recommended Practice 750, *Management of Process Hazards*. The development should follow established American National Standards Institute requirements for standard development. (P-12-17) (Closed—Exceeds Recommended Action)

This safety recommendation was issued in response to two accidents that occurred in 2010. The first accident occurred on July 25, 2010, when a hazardous liquids pipeline ruptured in Marshall, Michigan, and released an estimated 843,444 gallons of crude oil that saturated surrounding wetlands and flowed into the Talmadge Creek and the Kalamazoo River (NTSB 2012). The second accident occurred on September 9, 2010, when a natural gas transmission pipeline ruptured in a residential area in San Bruno, California, killing eight people, injuring many more, and destroying 38 homes (NTSB 2011).

Both accidents involved errors in control center operations where delays in identifying and responding to the releases exacerbated the consequences. We found that pipeline safety would be enhanced if pipeline companies implemented safety management systems. American National Standards Institute (ANSI)/API Recommended Practice (RP) 1173, *Pipeline Safety Management Systems*, was issued on July 8, 2015, which satisfied that recommendation (API 2015).

The flexible and scalable PSMS approach within ANSI/API RP 1173 builds upon pipeline operators' existing pipeline safety programs, many of which are required by PHMSA's minimum federal safety standards, to improve safety performance. The RP notes that the 10 essential elements comprising the framework apply to organizations of any size and sophistication.[29]

The following principles, in part, form the basis of the recommended practice:

- Pipelines are designed, constructed, operated, and maintained in a manner that complies with federal, state, and local regulations.
- Defined operational controls are essential to the safe design, construction, operation, and maintenance of pipelines.
- Prompt and effective incident response minimizes the adverse impacts on life, property, and the environment.

ANSI/API RP 1173 also discusses that a positive safety culture is essential to an organization's safety performance.[30] Some examples of a positive culture are: allocating adequate resources to assure individuals can successfully accomplish their PSMS responsibilities, promoting a questioning and learning environment, and reinforcing positive behaviors and why they are important.

[29] The essential elements include: leadership and management commitment; stakeholder engagement; risk management; operational controls; incident investigation, evaluation, and lessons learned; safety assurance; management review and continuous improvement; emergency preparedness and response; competence, awareness, and training; and documentation and record keeping.

[30] *Safety culture* is the collective set of attitudes, values, norms, beliefs, and practices that a pipeline operator's employees and contractor personnel share with respect to risk and safety.

There have been several voluntary initiatives to implement PSMS throughout the pipeline industry.[31] For example, in July 2018, the American Public Gas Association passed a Board Resolution that included 10 action items it reported aligned with the 10 elements of ANSI/API RP 1173. On May 21, 2019, the American Gas Association approved a resolution recommending all its members implement PSMS within 3 years. Similarly, API requires all members to commit to its Energy Excellence program, which it reported includes the 10 elements in ANSI/API RP 1173. Other industry stakeholders have encouraged voluntary implementation of PSMS across the industry. In its 2022 Annual Report, the PSMS Industry Team indicated that, according to its annual survey results, nearly 85% of total pipeline industry mileage is covered by a PSMS.[32] PHMSA recently gathered information through a voluntary information collection request to determine how many gas distribution operators are implementing PSMS in accordance with ANSI/API RP 1173.[33] PHMSA's preliminary results indicate that about 86% of all gas distribution mileage is operated by operators who have begun implementing PSMS voluntarily. Through our investigations, we have observed that several companies have implemented a PSMS voluntarily.

When the NTSB asked Beta if they have a PSMS, Beta shared information about their BSEE-required Safety and Environmental Management System program, PHMSA-required integrity management program, pipeline specific operations and maintenance manual, and spill training.[34]

1.9 Personnel Information

1.9.1 Pipeline Controllers

Two pipeline controllers were typically on Platform Elly. The pipeline controllers worked on the platform for 2-week periods, followed by 2 weeks off. During the 2-week periods on the platform, they typically worked 12-hour shifts each day, followed by 12 hours off. Beta had provisions for extended work hours in the event of an outage or unplanned safety critical task, including exceptions for

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[31] PHMSA has not required PSMS or incorporated ANSI/API RP 1173 into pipeline safety regulations.

[32] 2022-Pipeline-SMS-Annual-Report.pdf (pipelinesms.org)

[33] *Federal Register*, Volume 88, April 11, 2023, pages 21,742-21,746.

[34] The Safety and Environmental Management System program is a performance-based program that promotes safety and environmental protection. See: 30 *CFR* 250.1902.

unplanned shifts or callouts. The procedures required that controllers have an opportunity for 8 hours of continuous sleep between shifts.

The San Pedro Bay Pipeline controllers had received on-the-job training. According to the dayshift controller, they periodically ran drills for an oil leak response. They did not train using a simulator and had not received formal training on the leak detection system.

The dayshift controller who was on duty when the release was first detected had over 13 years' experience with the San Pedro Bay Pipeline. He started working in 2008 for Pacific Energy, which operated the facility at the time. He started as a well bay operator, gaining experience on operations in the Platform Elly and Ellen control rooms. At the time of the oil release, he had been working as a pipeline controller for 3 years.

September 30 was the first day of the dayshift controller's 2-week shift on Platform Elly. He told investigators he got about 4 hours 45 minutes of sleep the night before he arrived at Platform Elly to begin his shift. Although normally pipeline controllers worked 12-hour shifts, the dayshift controller worked from about 0600 on September 30 until about 0100 on October 1—an 18-hour shift—due to the nightshift controller experiencing unforeseeable travel delays related to wildfires and not arriving on time. The dayshift controller told investigators that he went to bed about 0200 and then woke up about 0430 for his next shift. The dayshift controller was again at the console for the San Pedro Bay Pipeline from about 0500 to about 1800 on October 1. On October 2, he assumed duty at the console about 0600 and was on duty when the right-of-way inspectors discovered oil in the water.

The nightshift controller had over 43 years of experience in offshore production. He started working offshore on Platform Elly around 1996 as a facility operator. He trained and became a control room operator and had served in that position on Platform Elly for the last 8 years.

The nightshift controller was awakened about 1400 on October 1 to help troubleshoot the problem with the knockout tank. He stayed awake and assumed duty at the console from about 1800 until about 0600 on October 2.

In accordance with 49 *CFR* 199.105(b), an operator must drug test each employee whose performance of a function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. An operator may elect not to test based on specific information that the employee's performance had no role in the cause or severity of the accident. After the oil release was confirmed, Beta did not perform alcohol or other drug testing on the controllers on duty or field staff. According to Beta, they did not conduct testing because at the time of the crude oil release, the cause was unknown.

1.9.2 *Beijing*

The master of the *Beijing*, who was on the bridge beginning about 0356 on January 25, 2021, held a merchant marine credential as a master on ships of 500 gross tonnage or more issued by Ukraine and endorsed by Liberia, the Marshall Islands, and Malta. He had nearly three decades' experience sailing as a mariner, 15 years as a master. He had sailed on containerships since 1993 and had worked for the same management company for 20 years. He served as master of the *Beijing* from December 2020 to May 2021.

The chief officer, who was on the bow as the vessel initially attempted to heave in its anchor, held a merchant marine credential as a chief mate on ships of 500 gross tonnage or more issued by Ukraine and endorsed by Liberia. He had 11 years' experience sailing as a mariner, with a little over a year and a half as a chief officer. He had sailed on containerships since 2015 and had worked for the same management company for 10 years. He served as the chief officer of the *Beijing* from September 2020 to January 2021 (he served on the vessel again later in 2021).

The second officer, who was on the bridge when the *Beijing* began dragging anchor, held a merchant marine credential as an officer in charge of a navigational watch issued by the Philippines and endorsed by Liberia, the Marshall Islands, and Malta. He had 32 years' experience sailing as a mariner, 17 years as a second officer. He had sailed on containerships since 2013 and had worked for the same management company for 8 years. He served as the second officer of the *Beijing* from December 2020 to November 2021.

Work/rest records for the crew of the *Beijing* indicated that the master, chief officer, and second officer each had at least 13 hours of rest per day in the 4 days before the anchor dragging on January 25, 2021, with at least one break per day lasting 8 hours or more.[35]

The *Beijing* officers and crew were not aware of the marine casualty that had occurred as a result of the anchor dragging or the potential impact to the pipeline; thus, they did not perform alcohol or other drug testing.

[35] International Maritime Organization work/rest records indicate mariners' on- and off-duty hours.

1.9.3 *MSC Danit*

The master came to the *MSC Danit* bridge between 0500 and 0530 on January 25, 2021, and was on the bridge while the ship dragged anchor. The master held a merchant marine credential as a master on ships of 3,000 gross tonnage or more issued by Montenegro and endorsed by Panama. He had nearly 23 years' experience sailing as a mariner, 8.5 years as a master. He had sailed on containerships for 16.5 years, working for the same management company. He served as master of the *MSC Danit* from June 2020 to March 2021.

The chief officer of the *MSC Danit* stood the 0400 to 0800 and 1600 to 2000 watches daily and had the navigation watch when the vessel dragged anchor on January 25. The chief officer held a merchant marine credential as a master on ships of 3,000 gross tonnage or more issued by Montenegro and endorsed by Liberia and Panama. He had 22 years' experience sailing as a mariner, 7 years as a chief officer. He had sailed on containerships for 18.5 years, working for the same management company. He served as chief officer of the *MSC Danit* from June 2020 to February 2021.

Work/rest records for the crew of the *MSC Danit* indicated that the master and chief officer each had at least 12 hours of rest per day in the 4 days before the anchor dragging on January 25, 2021, with at least one break per day lasting 8 hours or more.

The *MSC Danit* officers and crew were not aware of the marine casualty that had occurred as a result of the anchor dragging or the potential impact to the pipeline; thus, they did not perform alcohol or other drug testing.

1.9.4 Vessel Traffic Service Los Angeles-Long Beach Watchstanders

The VTS LA-LB watch team consisted of three personnel: a civilian watch supervisor employed by MAREX, a second MAREX civilian, and a uniformed Coast Guard servicemember. Watch teams stood 12-hour watches, from 0530 to 1730 or from 1730 to 0530, in a 3-days-on/3-days-off work schedule. The watchfloor had two positions: (1) a controller who monitored the Kongsberg maritime surveillance system and communicated with vessels via VHF radio and (2) a "desk" watchstander who answered phone calls and managed the MAREX arrival/departure information system. All three watch team members rotated through the two watchfloor positions, with one watchstander taking a break, meaning that at all times there were two watch team members on watch and one watch team member taking a break. The watch team rotated stations about every 2 hours. If needed during emergencies or high traffic periods, the watchstander on break could be called up to assist the controller and desk watchstander.

To qualify as a watchstander at VTS LA-LB, personnel were required to attend a Coast Guard-certified VTS course, which included simulator and classroom instruction, at a civilian training center. A prospective watchstander was also required to conduct on-the-job training with qualified watchstanders at VTS LA-LB, completing a qualification process developed by VTS LA-LB, and sit for a qualification board. Watch supervisors were required to complete a more comprehensive qualification and board process.

According to watchstanders interviewed by the NTSB and Coast Guard, on-the-job training included instruction on the various hazards in the VTS area of responsibility, including the potential hazard of anchor dragging near the San Pedro Bay Pipeline due to its proximity to the anchorage areas.

The night watch supervisor, who was the controller on watch when the anchor dragging began, had over 20 years' experience as a watchstander and watch supervisor at VTS LA-LB. The night civilian watchstander was the desk watchstander when the anchor dragging began and took over the controller watch following the *CMA CGM New Jersey/Ever Front* collision that morning. He had 9 years' experience as a qualified watchstander at the facility. The night Coast Guard watchstander was on break when the anchor dragging began and was called up to assist the two civilian watchstanders after the *CMA CGM New Jersey/Ever Front* collision. He had qualified as a VTS watchstander in 2019, when he was assigned to the facility. The day watch supervisor, who was on the controller watch starting about 0530 on the morning of the anchor dragging, had 17 years' experience as a qualified watchstander and 11 years' experience as a watch supervisor.

All VTS watchstanders stated that they got between 6 and 8 hours of uninterrupted sleep each day or night (night watchstanders sleeping during the day). Watchstanders were permitted to take naps while on their 2-hour break during their work rotation.

Following their watch on January 25, 2021, the two MAREX civilian VTS watchstanders submitted to postcasualty alcohol and other drug testing due to the *CMA CGM New Jersey/Ever Front* collision. The results were negative. The uniformed Coast Guard servicemember watchstander was not tested following the collision but was subject to random testing under Coast Guard policies.

1.10 Tests and Research

On October 26, 2022, a section of the deformed and displaced pipeline that contained the leak site was removed from the San Pedro Bay Pipeline in six segments, totaling about 250 feet, and brought to the surface as shown in figure 16. A 9-foot segment of pipe was removed from one of the sections and was sent for evaluation at the NTSB materials laboratory in Washington, DC.

Figure 16. Six segments of damaged pipeline removed for replacement. The leak site, circled in red, was observed on the segment shown wrapped in a tarp.

The segment contained the site of the crack where the leak occurred, which had been temporarily repaired with a welded patch so remaining crude oil could be flushed from the line (see figure 17).

Figure 17. Opposite ends of the pipe segment that contained the leak site, which had been temporarily repaired with a welded repair patch, visible in the right image. Damage signatures observed included lateral deformation, out-of-roundness deformation (a typical example indicated at the end of the segment in the right image), and missing concrete coating, especially north of the leak site.

The NTSB materials laboratory removed the repair patch to examine the leak site and found a visible primary crack, about 18 inches long, on the outer surface of the pipe running along the toe of the seam weld located about the 11 o'clock position as shown in figure 18.[36] A visible secondary crack running along a gouge in the outer surface below the seam weld arrested at the primary crack. The primary crack exhibited a relatively flat fracture surface preceded by multiple origin areas near the outer surface with a curved boundary that extended to a maximum of 0.3 inches through the pipe wall, which indicated the primary crack progressed inward over time before the leak event. The pipe was deformed about 2.5 inches inward at the crack location and about 2 inches inward diametrically opposite of the crack and appeared generally ovalized (bulged at the 3 and 9 o'clock positions). The results of mechanical and chemical testing of the pipe were consistent with the API

[36] *Weld toe* refers to the location of the joint where the weld face meets the parent metal.

standards and showed no apparent discrepancies for the as-manufactured pipe material.

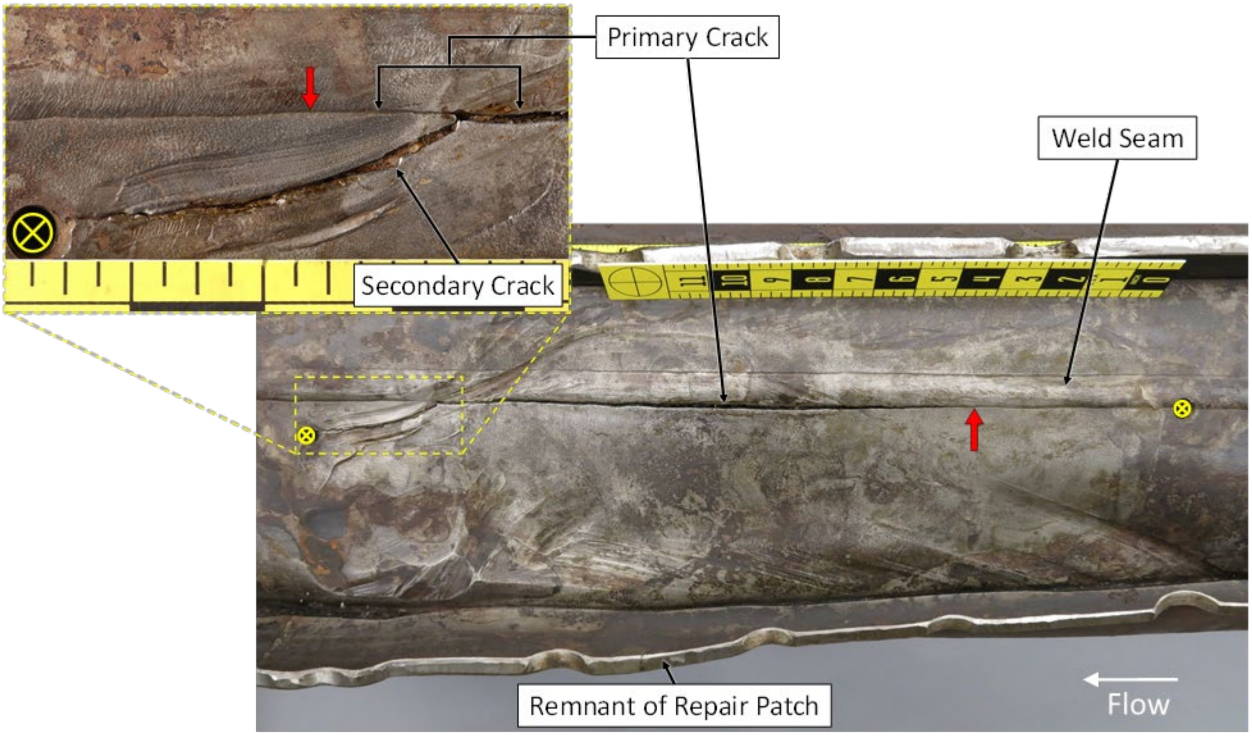

Figure 18. A closer view of the leak site from the outer surface after removal of the repair patch showing general inward deformation, localized gouges, parallel scratches, and smeared metal. The red arrows mark the ends of a visible primary crack along the seam weld toe. The two holes denoted by a yellow circled *X* were introduced following underwater nondestructive testing to prevent further cracking. Inset scale markings are 0.25 inches.

On November 25, 2022, an additional two segments of pipeline that had been located along the displaced length of pipeline to the south of the leak location were brought to the surface. The NTSB examined photographs of these pipeline segments, which totaled about 75 feet in length (see figure 19). The concrete coating was damaged or missing along parts of the segments, and a portion of the pipe was deformed (out-of-round).

Figure 19. End of segment that had been located along the displaced length of pipeline to the south of the leak locations, showing out-of-roundness deformation. (Source: PHMSA)

1.11 Follow-up Actions

1.11.1 Los Angeles/Long Beach Anchorage Actions

1.11.1.1 Reduction in Los Angeles/Long Beach Port Loading

Between September and November 2021, MAREX worked with industry stakeholders to change the queuing system for commercial ships calling on the ports of Los Angeles and Long Beach, with the goal of reducing the number of ships at anchor, drifting, or loitering. Under the old system, ships did not enter the queue for shore labor at a terminal until they arrived within 20 miles of the ports. Therefore, ships bound for Los Angeles or Long Beach would cross the Pacific Ocean at full speed, then anchor, drift, or loiter (sometimes for weeks) near the port awaiting labor and a berth to discharge cargo.

Under the new system, ships entered the queue upon departure from their last port of call. The vessels could then slow their cross-Pacific transit speed or loiter outside the Southern California area until 3 days before their berthing assignment date. On November 16, 2021, the day that the new queuing system was implemented, 86 container vessels that had entered the queue under the old system were anchored, drifting, or loitering within 40 miles of the ports of Los Angeles and Long Beach. By January 9, 2021, 109 containerships were in the queue (23 more than were in the queue on November 16), yet only 12 were anchored, drifting, or loitering near the ports, and these 12 vessels were within 3 days of their assigned berthing times. The remaining 97 containerships in the queue were voluntarily waiting more than 50 miles from land.

1.11.1.2 Changes to Vessel Traffic Service Los Angeles-Long Beach Anchorage Procedures and Federal Anchorages

In October 2021, as a result of the crude oil release, VTS LA-LB added a graphic overlay for the San Pedro Bay Pipeline, as well as another pipeline that ran near anchorages in the area, to its Kongsberg maritime surveillance system display to provide watchstanders with additional awareness of the pipeline locations.

Also in October 2021, following the discovery of the oil release, VTS LA-LB and the Coast Guard agreed to discontinue the use of anchorage positions F-16, SF-2, SF-3, and SF-12 due to their proximity to the San Pedro Bay Pipeline. Additionally, they discontinued the use of two contingency anchorages off Huntington Beach, California, due to their proximity to a sewage outfall.

In November 2021, VTS LA-LB proposed a plan for restructuring the federal anchorages in San Pedro Bay, which increased the distances between anchorage positions, reduced the number of positions from 48 to 28, and increased the distances from the anchorages to the San Pedro Bay Pipeline and Huntington Beach sewage outfall. Specifically, the new plan increased the distance between the San Pedro Bay Pipeline and the centers of anchorage positions in Anchorage F to a minimum of 1 mile. As of the date of this report, VTS LA-LB is working with the Coast Guard to implement the plan through the federal rulemaking process.

While the permanent restructuring proposal was under consideration, VTS LA-LB reduced the number of anchorage positions to which it was assigning ships beginning in December 2021. After the reduction, only 21 out the existing 48 positions (including contingency anchorages) were assigned to ships, allowing more space between anchorage positions.

1.11.1.3 Changes to Vessel Traffic Service Los Angeles-Long Beach Heavy Weather Notifications and Procedures

In December 2021, VTS LA-LB, in collaboration with the Coast Guard, instituted a new process for assigning anchorage positions and advising vessels in the anchorages during impending heavy weather. Forty-eight hours before a forecasted heavy weather event, VTS LA-LB will not assign any new vessels to anchorages that lie outside of the ports' breakwaters, including Anchorages G and F and the contingency anchorage positions. VTS LA-LB will individually contact all vessels already at anchor in the anchorages outside the breakwater, advise them to monitor weather conditions, and ask if the vessels intend to leave the anchorage before the weather event. As necessary, VTS LA-LB will contact vessels 12 and 24 hours before the event to determine if they intend to remain in the anchorage or depart. VTS LA-LB will notify the Coast Guard Sector LA-LB Prevention Department of those vessels deemed high risk due to size, type, or proximity to hazards, and the Prevention Department will encourage those vessels to depart. The Coast Guard Captain of the Port may issue an order directing the vessel to depart. VTS LA-LB will initiate a weather information broadcast 12 hours before a forecasted heavy event or as soon as possible for an unforecasted event.

1.11.1.4 Anchorage Risk Assessments

In May 2022, the Coast Guard Office of Waterways and Ocean Policy directed Coast Guard District, Sector, and Marine Safety Unit waterways managers throughout the US to conduct risk assessments for all federal anchorage grounds. The Office of Waterways and Ocean Policy required the risk assessment to address navigational safety; protection of the marine environment; proximity to subsea pipelines, cables, tunnels, or other infrastructure; safe and efficient use of the maritime transportation system; and the national security of the United States.

The directive instructed Districts to modify existing anchorage grounds or establish new anchorage grounds, if needed, via the federal rulemaking and National Environmental Policy Act processes, after informing Congress of proposed modifications.

In its justification for the risk assessments, the Office of Waterways and Ocean Policy stated,

> Changing demand patterns and increased interest in global commerce have generated concerns about navigation safety and environmental impacts caused by established anchorage grounds. Ongoing supply chain disruptions, caused by COVID-19, have magnified these concerns, as the volume of commercial vessels anchored in U.S. waters has reached unprecedented levels.

Anchorage risk assessments were to be carried out within 1 year of the directive and every 7 years thereafter. At the time of publication of this report, the risk assessment for the ports of Los Angeles and Long Beach, including the San Pedro Bay anchorages, was in progress.

1.11.2 Pipeline Safety Actions

1.11.2.1 Pipeline and Hazardous Materials Safety Administration

On October 4, 2021, PHMSA issued a Corrective Action Order (CAO) to Beta Offshore. The CAO required 15 specific correction actions, including that the San Pedro Bay Pipeline remain shut down until corrective measures were undertaken. The CAO also required testing of the failed pipe, inspection of the integrity of the pipeline, an operating pressure restriction, and PHMSA approval before the pipeline returned to service. Beta adhered to all elements of the CAO before the San Pedro Bay Pipeline was restarted on April 8, 2023, with the exception of a requirement to provide a metallurgical report (PHMSA granted an extension on this item).

In addition to the CAO, after the accident, PHMSA conducted a compliance review related to the pipeline operations leading up to the accident, which resulted in a Notice of Probable Violation, a Proposed Civil Penalty in the amount of $3,389,734, and Proposed Compliance Order issued to Amplify on April 6, 2023.

The Notice of Probable Violation identified 10 probable violations of the Pipeline Safety Regulations. A summary of those items, according to PHMSA, included:

- 49 *CFR* 195.52, *Immediate notice of certain accidents*. PHMSA found that on October 1, 2021, about 1610, Beta received two leak detection alarms.[37] By 1615, the estimated leak amount generated was 33.95 barrels of crude oil. Despite multiple leak alarms and corresponding leak size estimates, Beta did not notify the NRC until 17 hours after the first leak alarms, when its contractor called the NRC on October 2, 2021, at 0907.

- 49 *CFR* 195.401, *General requirements*. PHMSA found that Beta operated its pipeline at a level of safety that was lower than required. Beta personnel decided to use the operator's manual leak detection procedure to try to identify the leak while the pipeline continued to operate. However, the manual leak detection procedure was only to be used "in the event of a communication breakdown between Platform Elly and the Beta Pump Station." PHMSA found there was no communication breakdown between these locations during the failure event. Additionally, PHMSA found that, despite 83 total leak alarms, Beta did not immediately shut down the line and, instead,

[37] PHMSA counted all leak alarm signals as individual alarms, while this report considered each alarm series as one leak alarm. PHMSA identified 83 total leak alarms.

continued to operate the pipeline and engage in manual leak detection, effectively pumping oil into the pipeline and subsequently the San Pedro Bay.

- 49 *CFR* 195.402, *Procedural manual for operations, maintenance, and emergencies*. PHMSA found Beta failed to follow its written procedures for normal operations, maintenance activities, abnormal operations, and emergencies. Despite receiving two leak alarms about 1610 on October 1, 2021, Beta controllers did not immediately shut down and isolate the pipeline, did not notify the person-in-charge until 1915 (after more alarms), and continually cycled the shipping pumps on and off without closing any valve in an effort to clear the alarms and without performing additional actions to investigate the cause of the alarms. Beta could not provide any records to demonstrate that it annually simulated emergency shutdown, isolation, and drawdown with its personnel for the past 5 years. Beta's controllers were not trained on its leak detection system, as required.

- 49 *CFR* 195.446, *Control room management* (five probable violations). Beta controllers did not document shift change information, as required, and failed to follow its procedure by allowing its dayshift controller to work for 22.5 hours, releasing him, and then allowing him to report for duty just 2.5 hours later. Additionally, although the pipeline superintendent directed the controller to place the leak detection system into "sleep" mode, the pipeline superintendent was not identified in Beta's procedures as someone who had the authority to direct the controller's actions.[38] Beta also failed to educate controllers and supervisors in fatigue mitigation strategies, how off-duty activities contribute to fatigue, and how to recognize the effects of fatigue, as required. Beta failed to provide training to its controllers to carry out their roles and responsibilities, such as: (1) responding to abnormal operating conditions likely to occur simultaneously or in sequence, (2) providing controllers with a working knowledge of the pipeline system, especially during the development of abnormal operating conditions, (3) providing an opportunity for controllers to review relevant procedures in advance of their application for setups that are periodically, but infrequently used, and (4) providing control room training and exercises that include both controllers and other individuals, defined by the operator, who would reasonably be expected to operationally collaborate with controllers during normal, abnormal, or emergency situations.

[38] Sleep control is a type of command intended for use during instrument maintenance or other such cases where the system is liable to see large changes for no operational reasons. It causes leak detection to be disabled and inhibits the alarms.

- 49 *CFR* 195.505, *Qualification program*. Beta failed to ensure through evaluation that individuals performing covered tasks were qualified.[39] PHMSA found that the controllers who were present at the time of the accident had missed some years of required training, including training on abnormal operating conditions.

- 49 *CFR* 195.54, *Accident reports*. Beta failed to file an accident report to PHMSA within 30 days after discovery of the accident. The required accident report was filed on December 3, 2021.

The Proposed Compliance Order, if implemented, would require Beta to amend its procedures; train all facilities operators, control room operators, persons-in-charge, supervisors, superintendents, and safety personnel on the amended procedures; and provide training to all controllers and supervisors on fatigue risk management.

As of October 5, 2023, Amplify is contesting PHMSA's findings, asserting that there were no underlying violations and that the proposed civil penalty should be withdrawn or substantially reduced. However, Beta agreed to the proposed compliance conditions.

1.11.2.2 Beta Offshore/Amplify

Beta was also charged in federal and state courts related to the oil release and committed to 14 safety improvements as part of its federal and state plea agreements. These conditions and improvements include: (1) additional training on spill notifications; (2) immediate reporting of any leak detection alarm to the California Office of Emergency Services State Warning Center; (3) semi-annual ROV inspections; (4) comprehensive review and revision of Beta's procedures; and (5) mandatory training for operational employees and related management personnel on the updated policies and procedures.

1.11.2.2.1 Evaluation of Pipeline-Related Procedures and Training

Amplify evaluated procedures for Beta's operations of the offshore facilities, including a month-long review of control room procedures. As a result, they revised several procedures. Additionally, they evaluated revisions to about 150 noncritical

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[39] A *covered task* is an activity identified by an operator that is performed on a pipeline facility, is an operations or maintenance task, is performed as a requirement of 49 *CFR* Part 192, and affects the operation or integrity of the pipeline.

procedures. Amplify reported that they would train and test the crew on all revisions before restarting the San Pedro Bay Pipeline, subject to PHMSA approval.

1.11.2.2.2 Increased Staffing

Amplify evaluated staffing levels for each element of its pipeline-related operations. As a result, Beta will increase its staffing on Platform Elly to provide for three control operators (an increase of one per crew) and three plant operators (an increase of one per crew) for a 3-year testing period, after which they will reevaluate their offshore staffing.

1.11.2.2.3 Leak Detection System Update

Beginning in December 2021, Amplify and Beta installed a new leak detection system on the San Pedro Bay Pipeline to improve the accuracy of its leak alarm locations. The new leak detection system is a site-specific product that is designed for the type of crude oil in the line, including its viscosity, specific gravity, temperatures, and volumetrics. Beta planned to perform three tests to ensure the system was functioning properly. The leak detection system contractor personnel trained the crews before Amplify restarted the San Pedro Bay Pipeline, and the crews will train annually thereafter.

1.11.2.2.4 Communications Infrastructure Update

After the pipeline leak, Beta invested about $180,000 to overhaul the communication networks servicing the platforms and onshore facilities. These improvements addressed the major network hardware components that connect the offshore platforms to land. Beta also installed three sets of new high capacity, long-distance microwave radios that increase performance and reliability of network communications. As part of a separate, but related project, Beta also invested in a new SCADA human-machine interface system. According to Amplify, the improvements to the communications system have significantly reduced the number of communications losses and subsequent alarms.

2 Analysis

2.1 Introduction

On October 1, 2021, at 1610 local time, San Pedro Bay Pipeline controllers received the first of a series of leak alarms. Over the next 13 hours, the controllers conducted seven pipeline shutdowns and restarts while troubleshooting the alarms. At 0604 on October 2, controllers shut down the pipeline for the eighth and final time. At 0809, a pipeline contractor vessel crew visually confirmed that there had been a crude oil release, and Beta Offshore, the pipeline operator, initiated an oil spill response. An estimated 588 barrels of oil leaked from the pipeline. A postaccident underwater examination of the pipeline found a crack along the top of the pipeline within a section of the pipeline that had been displaced from its originally installed location. Additionally, scarring consistent with anchor dragging was identified on the seafloor near the crack location. Postaccident investigation by the Coast Guard and NTSB revealed that the containerships *MSC Danit* and *Beijing* had dragged anchor near the pipeline months before the oil release, on January 25, 2021.

This analysis identifies the following safety issues:

- Insufficient distance between anchorage locations and the pipeline (section 2.3)
- Need for notification of potential pipeline damage to the pipeline operator (section 2.4)
- Need for improvements to VTS vessel monitoring systems (section 2.4)
- Incorrect response by pipeline controllers to leak alarms (section 2.5)
- Lack of postaccident alcohol and other drug testing for pipeline controllers (section 2.6)
- Need for pipeline operators to implement pipeline safety management systems (section 2.7)

2.1.1 Exclusions

Having completed a comprehensive review of the circumstances that led to the pipeline leak, the investigation excluded the following as causal factors.

- *As-manufactured material condition of the pipeline*. The mechanical and chemical testing that the NTSB materials laboratory performed on the pipeline section near the crack found no apparent material discrepancies in the pipe, and the results were consistent with API standards.

- *Overpressurization of the pipeline*. Beta Offshore operated the pipeline below its maximum operating pressure of 1,152 psig and had a system that would automatically shut down shipping due to high pressure at 1,045 psig. The pipeline pressure did not reach these pressure levels before failure.

- *Experience and qualifications of the vessel crews and VTS personnel.* All officers involved in operating or supervising operations of the containerships *Beijing* and the *MSC Danit* at the time of the anchor dragging held valid merchant mariner credentials for the positions they were serving and had significant experience sailing on containerships. All watchstanders at VTS LA-LB were qualified in the watch stations at the facility and had significant experience as a watchstander.

- *Fatigue of vessel crews and VTS watchstanders.* The masters and bridge watchstanders on the *Beijing* and *MSC Danit* had at least 12 hours of rest time each day during the 4 days before the anchor dragging events on January 25, 2021, with at least one break per day lasting 8 hours or more. The VTS LA-LB watchstanders stated that they got between 6 to 8 hours of uninterrupted sleep when not on duty and could take naps while on break during their duty cycle.

Thus, the NTSB concludes that none of the following issues contributed to the pipeline leak: (1) pipeline as-manufactured material condition; (2) pipeline overpressurization; (3) experience and qualifications of the vessel crews and VTS personnel; or (4) fatigue of vessel crews and VTS watchstanders.

2.1.2 Alcohol and Other Drug Testing

The pipeline controllers on duty were not tested for alcohol and other drugs following the oil release discovery. According to Beta, they did not conduct testing because at the time of the release the cause was unknown (see section 2.6 for information about drug-testing deficiencies).

Because the pipeline did not leak until months after the anchor draggings and the crews of the *Beijing* and *MSC Danit* were not aware that pipeline damage occurred, the crews did not conduct alcohol and other drug testing.

VTS LA-LB watchstanders were not tested for alcohol or other drugs related to the anchor draggings, again because they were not aware that the pipeline was damaged. (MAREX watchstanders at VTS LA-LB were tested due to the *CMA CGM New Jersey/Ever Front* collision, and the results were negative.)

Therefore, the NTSB concludes that although there were no indications of alcohol or other drug use by the pipeline controllers on duty at the time of the crude oil release or *Beijing* and *MSC Danit* crewmembers on duty at the time of the anchor draggings, evidence was insufficient to determine whether alcohol or other drug use contributed to the pipeline leak and severity of the accident.

2.2 Pipeline Damage and Anchor Dragging

The San Pedro Bay Pipeline was displaced to the east of its original location up to a maximum distance of 105 feet, and the leak in the pipeline occurred at the apex of this displacement. An examination of the cracked section of the pipeline by the NTSB materials laboratory showed that the leak was most likely the result of delayed failure from a fatigue crack that originated in a deformed section of pipe along the seam weld toe and heat-affected zone.[40] Deformation damage that is insufficient to cause an immediate oil leak, such as a dent, creates a localized change in the smooth and uniform geometry of the pipe that disrupts the distribution of stress through the pipe wall from the internal fluid pressure. This stress becomes concentrated and locally amplified at the dent location, which can initiate cracking. In this case, once initiated, a stress concentration remained at the crack tip, and progressive crack growth continued due to cyclic loading from internal pressure fluctuations associated with normal pipeline operations. When the crack had grown to a point where the pipeline could no longer support the operating pressure of the system, a rupture to the pipe wall occurred.[41] The localized deformation and gouging of the pipe were consistent with an applied external mechanical load on the pipeline. The NTSB concludes that the release of crude oil occurred as a result of fatigue failure that manifested over a period of time in an area of local deformation to the San Pedro Bay Pipeline caused by an external force applied to the pipeline that resulted in

[40] a) *Fatigue* refers to a cracking mechanism that initiates and grows at a stable rate, under repeated application of cycles of stress, at a level below the yield stress. Failure occurs when the crack growth rate becomes unstable, resulting in rapid fracture. b) *Heat-affected zone* refers to the portion of the base metal that was not melted during welding where the microstructure and mechanical properties were altered by the heat.

[41] *Rupture*, as used in this materials analysis, refers to rapid material failure (fracture) that extended under the influence of an applied stress. This definition is separate and distinct from the pipeline operations definition of rupture, which is an unintentional or uncontrolled release of a large volume of commodity from a pipeline.

progressive cracks initiating and growing through the pipe wall until the pipe wall ruptured.

If the pipeline had been impacted once by an outside force, the pipeline would have been displaced a uniform distance on each side of the point of maximum displacement. The displacement of the San Pedro Bay Pipeline was not uniform on either side of the point of maximum displacement, suggesting that the displacement was the result of more than one external force applied to the pipeline. Postaccident surveys identified damage to other sections of the pipeline along the 4,025 feet of displaced length, including the loss of the concrete coating and deformation (out-of-roundness), which was also consistent with applied external forces (see figures 17 and 19 for examples of out-of-roundness deformation). Additionally, the surveys found several seabed scars along the length of the displaced section of pipeline that were indicative of anchors being dragged. The seabed scars were on the northwest side of the pipeline, impinging on the pipeline in several locations where the displacement occurred. One of the scar tracks led directly to the point of maximum displacement of the pipeline, which was also the location of the leak.

On January 25, 2021, the containerships *Beijing* and *MSC Danit* were anchored near the pipeline in VTS-assigned anchorage positions. When a strong cold front passed through the area, winds and seas increased significantly, and the *Beijing* and *MSC Danit*, along with several other vessels, dragged anchor. AIS data showed that, as the *Beijing* and *MSC Danit* were dragging anchor, they crossed the pipeline, from west to east, over the area where the length of displaced pipeline would eventually be found.

While the *Beijing* was dragging its anchor, the crew attempted to heave it in. However, the motor on the port windlass failed, preventing recovery of the anchor. The vessel reported to VTS LA-LB that, while the windlass was inoperable, the anchor remained in the water with 1.5 shots (135 feet) of chain. The master later reported the same amount of chain in his statement to the operating company. During a later interview, the second officer recalled that there were 5 shots (450 feet) on deck when the windlass failed.

Based on the movement of the *Beijing* while it dragged anchor and the differing lengths of anchor chain reported by both the master and the second officer, the NTSB modeled the *Beijing*, its anchor chain, and anchor to determine the possible locations of the anchor relative to the vessel on January 25, 2021 (see figure 20). The model was based on ship and anchoring system drawings and the charted water depth and assumed that the vessel was operating at its designed draft. Given the *Beijing*'s lateral movement when it initially dragged anchor, the model assumed that the anchor chain tended in the direction opposite the vessel's course over ground (by about 70°) during this time. The NTSB modeling found that, at 1.5 shots in the water, the anchor position would be off the *Beijing*'s port bow at 155 feet from the centerline of the vessel; at 5 shots on deck, the anchor position would be between 403 and 443 feet (dependent on the strain on the anchor chain) from centerline of the vessel, as shown at the top of figure 20.

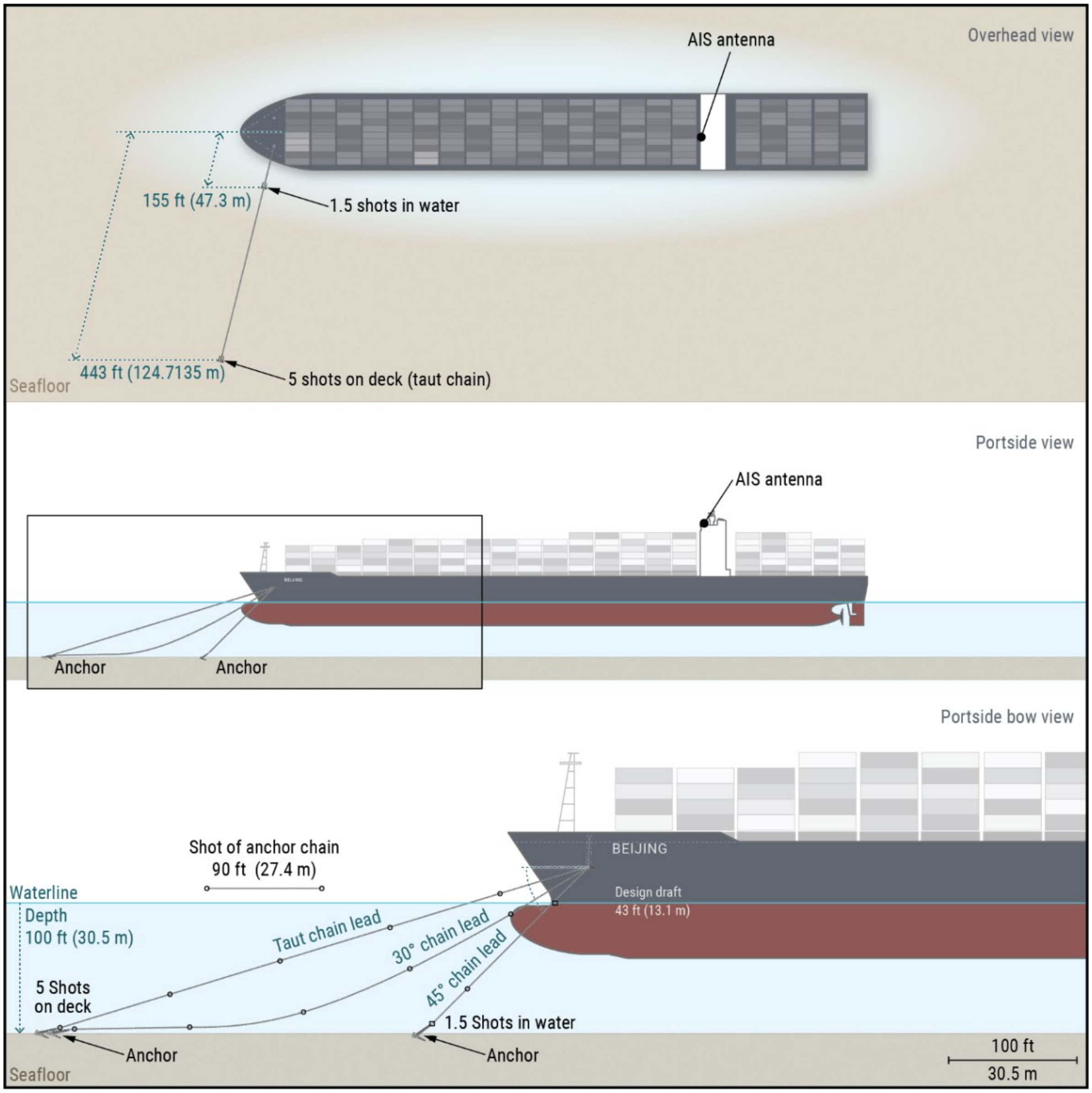

Figure 20. NTSB modeling of *Beijing* anchor position relative to the vessel for moderate to heavy strain on the anchor chain. (In the profile views, the anchor chain is shown tending directly ahead of the vessel for illustrative purposes.)

When the *Beijing* initially dragged anchor, it moved laterally eastward until its progress stopped with the bow 590 feet from where it had passed over the pipeline's charted location (see figure 21). Based on the NTSB's modeling of the *Beijing*'s anchor position (maximum of 443 feet off the bow), it is clear that the anchor would have struck the pipeline as the ship drifted past it.

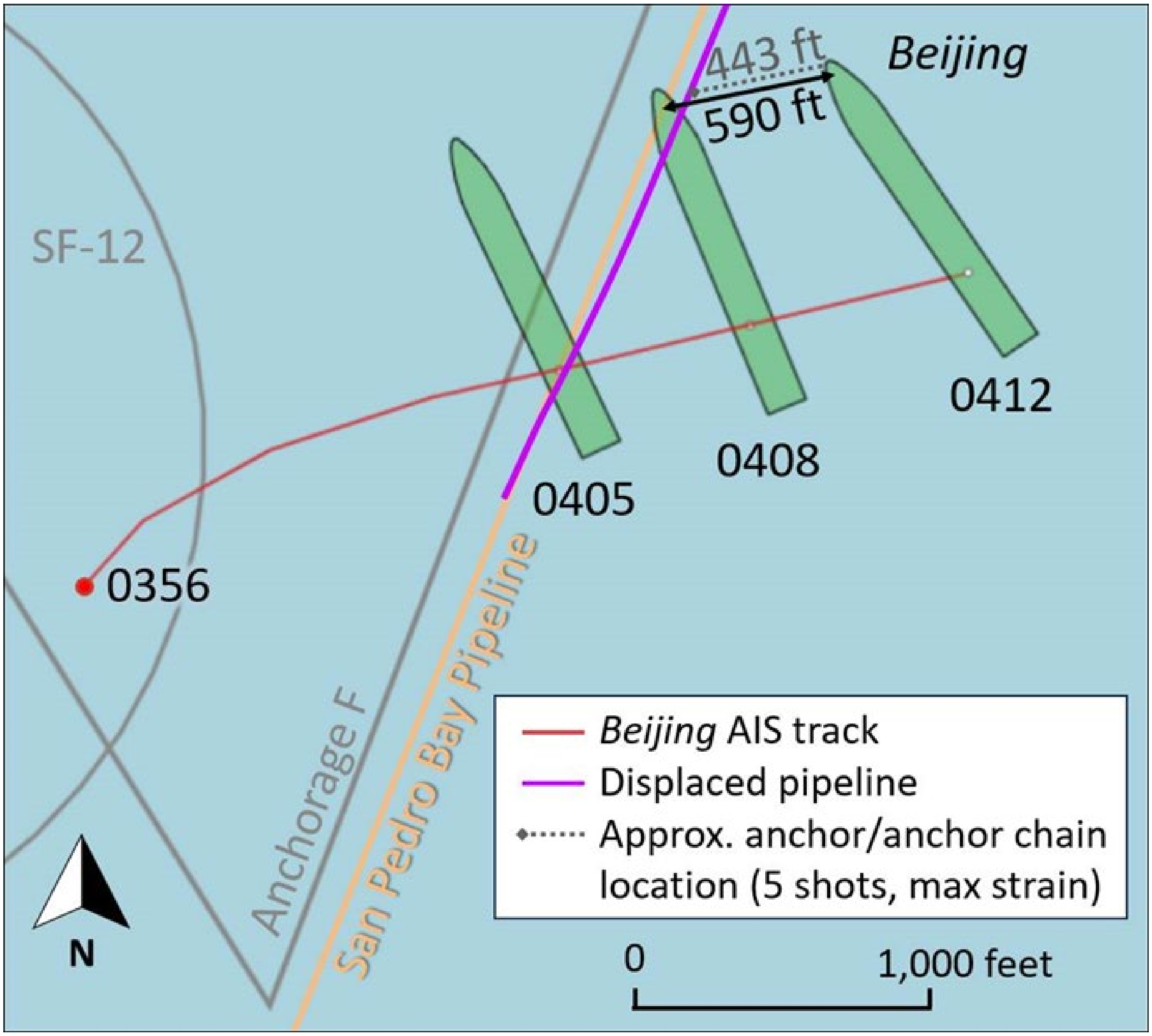

Figure 21. The *Beijing*'s position as the vessel dragged anchor over the San Pedro Bay Pipeline.

After its initial crossing over the San Pedro Bay Pipeline, the *Beijing* continued to maneuver near the pipeline, with the vessel's AIS position passing over the pipeline at least 10 times. The AIS position during this period was recorded as much as 1,044 feet east and 1,158 feet west of the charted pipeline location. Location data from anchor dragging scars on the seabed, when overlaid with the vessel's AIS data, indicate that the *Beijing* anchor likely struck the pipeline multiple times during this period (see figure 22). The pipeline was displaced and the concrete coating damaged in the locations where these incursions occurred.

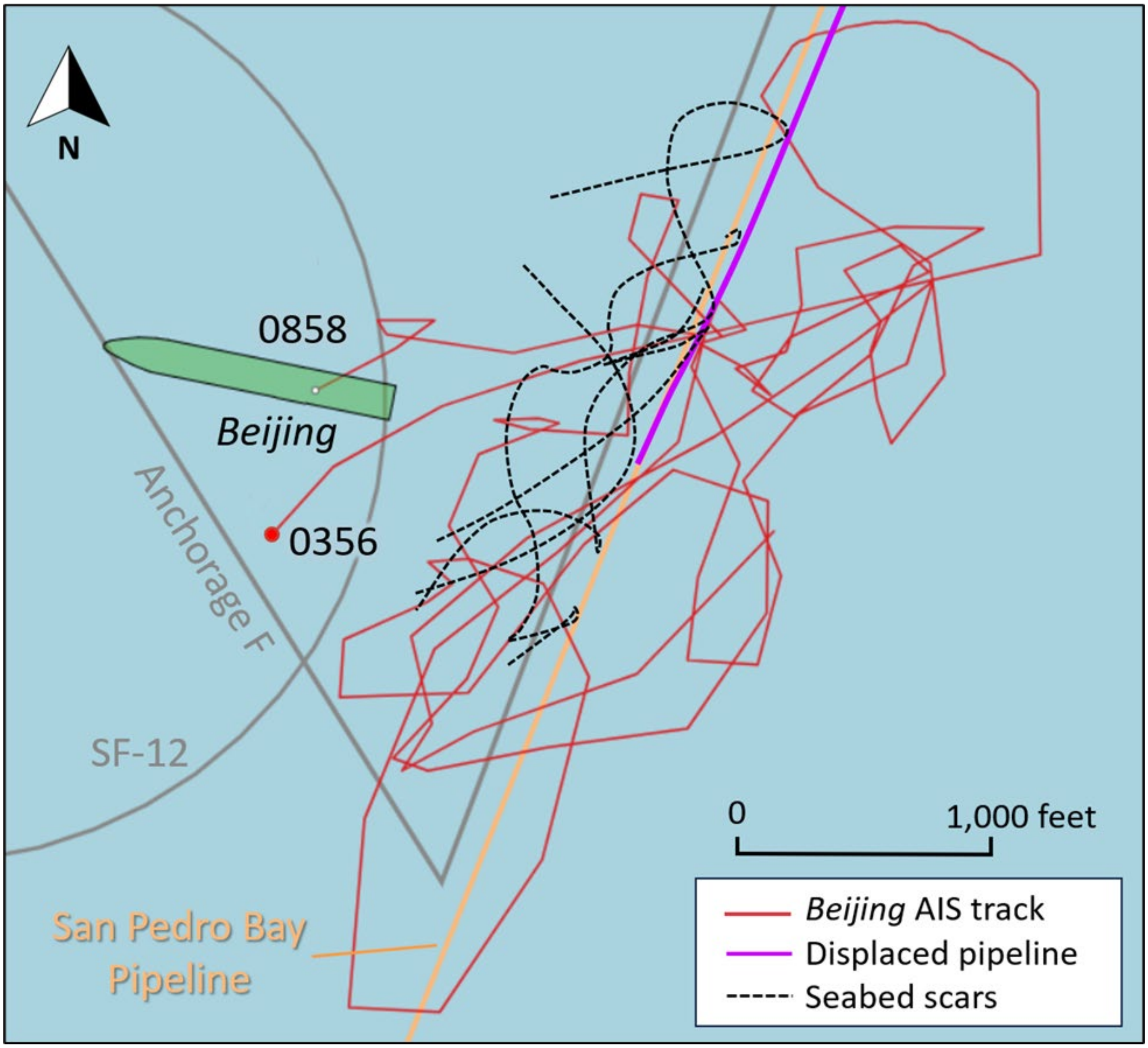

Figure 22. Location data from anchor dragging scars on the seabed, when overlaid with the *Beijing*'s AIS data, indicate that the *Beijing* anchor likely struck the pipeline multiple times.

The *MSC Danit* had originally payed out 7 shots (630 feet) of chain when it first anchored in San Pedro Bay on January 18. Although the *MSC Danit* had begun heaving in its anchor when it began dragging on January 25, the crew stopped heaving in and payed out 2 shots to avoid the tanker *Hong Kong Spirit*, which was dragging anchor in the *MSC Danit*'s direction. At this point, the *MSC Danit*'s deployed anchor chain was likely between 6 and 8 shots in length (540 and 720 feet, respectively).

Using the vessel's motion and a range of anchor chain lengths between 6 and 8 shots, the NTSB modeled the *MSC Danit*, its anchor chain, and anchor to determine a range of values representing the location of the anchor relative to the vessel's bow (see figure 23). Similar to the modeling of the *Beijing*, the NTSB assumed that the vessel was operating at its designed draft. Because the vessel moved in a generally astern direction, the model assumed that the anchor chain tended directly off the bow (any direction other than directly off the bow could be estimated using an arc of the length of the anchor chain). The NTSB modeling found that, at 8 shots (the maximum length of chain), the anchor position would be between 618 and 670 feet forward of the vessel's bow.

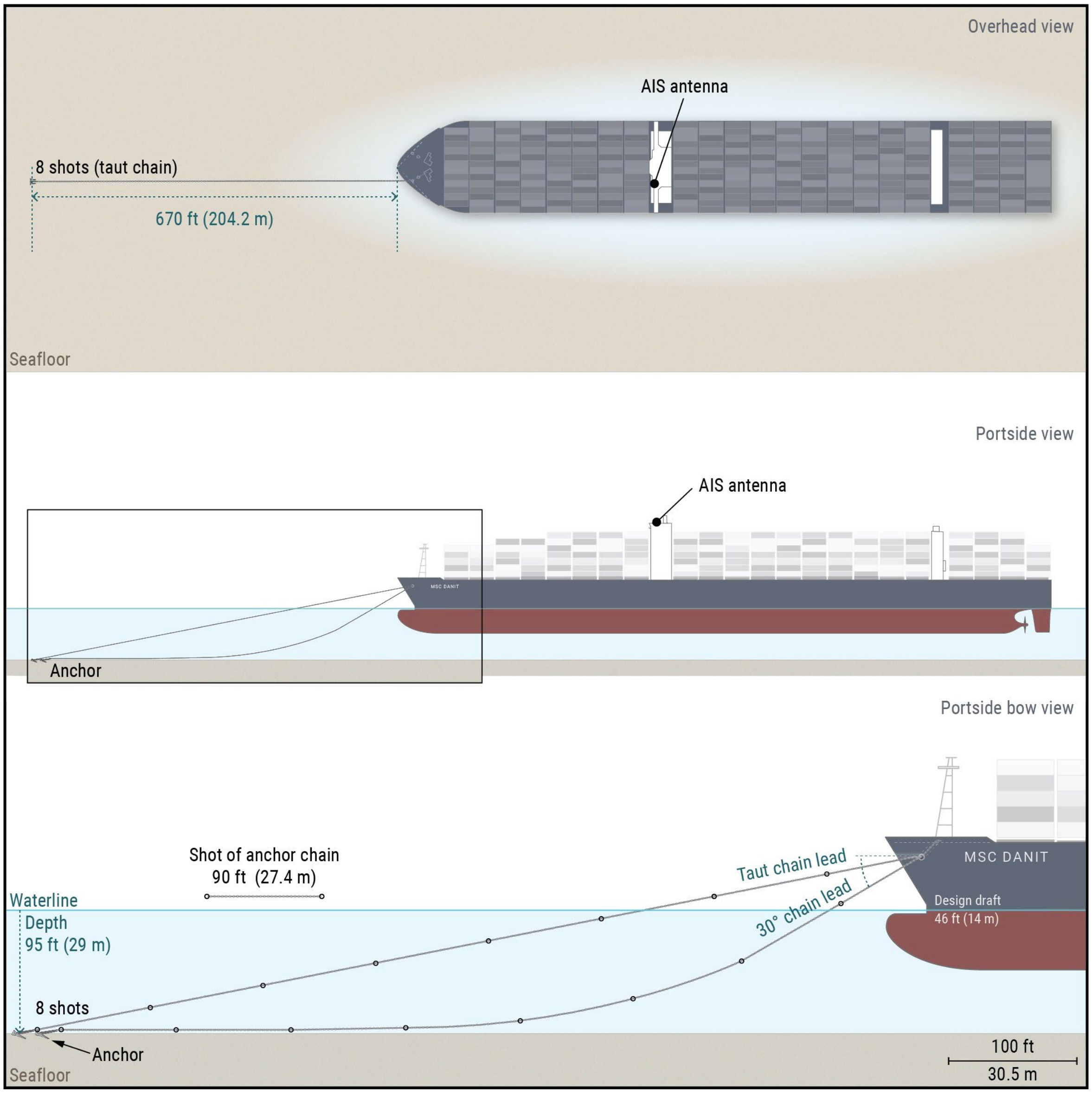

Figure 23. NTSB modeling of the *MSC Danit*'s anchor position relative to the vessel for moderate to heavy strain on the anchor chain.

As the *MSC Danit* drifted over the San Pedro Bay pipeline, the ship's crew used its engine to attempt to maintain position while they heaved in the ship's anchor. At

0617, *MSC Danit*'s eastward progress stopped when its bow was about 842 feet southeast of where the pipeline leak would eventually be found (see figure 24). Based on the NTSB's modeling of the *MSC Danit*'s anchor position (maximum of 670 feet forward of the ship's bow), the anchor would have struck the pipeline as the ship drifted past it (842 feet east of the leak location).

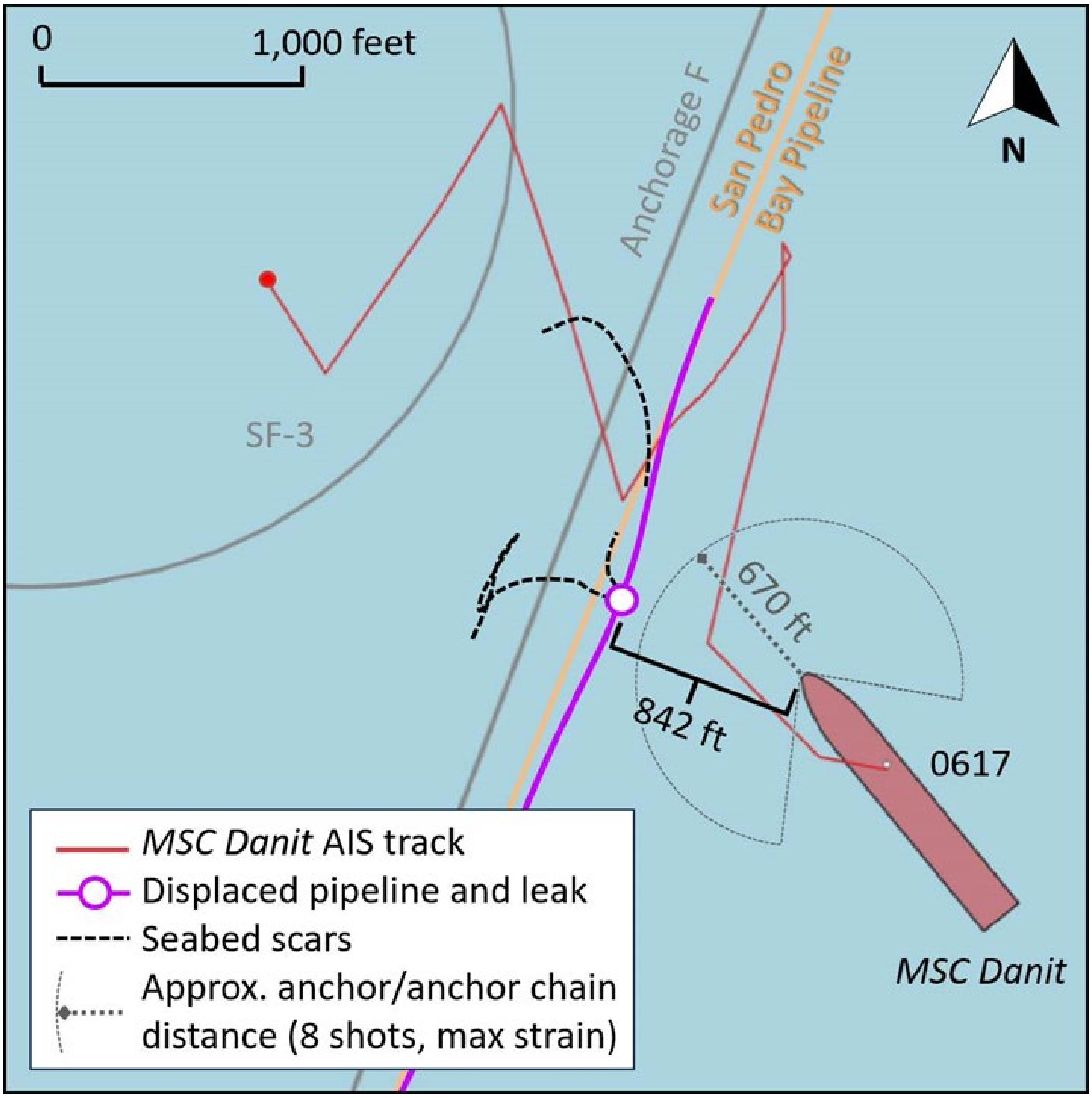

Figure 24. The *MSC Danit*'s position as the vessel dragged anchor over the San Pedro Bay Pipeline, the approximate distance of the anchor from the vessel, and location data from anchor dragging scars on the seabed.

After the *MSC Danit*'s eastward movement stopped, it remained in nearly the same position for 36 minutes. When the *Hong Kong Spirit* departed the anchorage, the *MSC Danit* again started heaving in its anchor and moved in a westerly direction. The vessel maneuvered directly over the pipeline—close to the apex of the pipeline's eastward displacement and the location where the leak was eventually found—and remained there for over an hour (see figure 25). Scars on the seabed indicated anchor dragging marks in the immediate area of the eventual leak location.

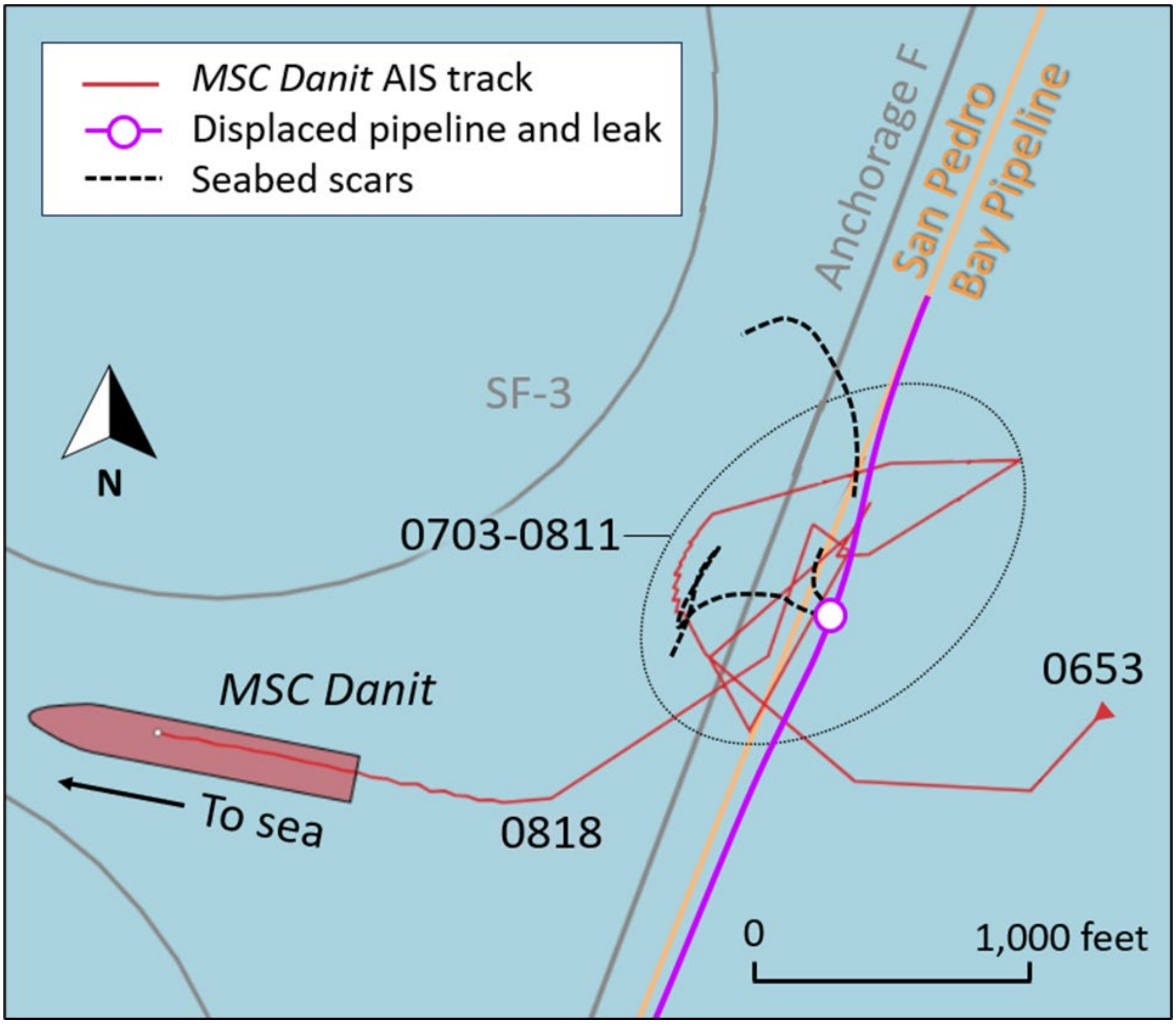

Figure 25. The *MSC Danit*'s AIS data indicated that the vessel maneuvered directly over the pipeline and remained there for over an hour.

Both the *Beijing* and the *MSC Danit* dragged anchor over the pipeline where it was later found to be displaced and damaged. Analysis of AIS data found that no other ships dragged anchor near the pipeline in the time between May 2020, when the last survey was conducted showing the pipeline intact in its original location, and October 2021, when the leak was found. Therefore, the NTSB concludes that, as a result of the winds and seas generated by a strong cold front, the containerships *Beijing* and *MSC Danit* dragged anchor, and the anchors struck, displaced, and damaged the San Pedro Bay Pipeline. (See section 2.3 for further discussion of the crew's performance as the anchors dragged and the location of the anchorage.)

The NTSB materials laboratory found that the crack in the pipeline originated from an area of localized deformation, suggesting that the damage that specifically led to the crack was the result of an anchor strike at the leak location. The *Beijing* passed over the pipeline numerous times, with its anchor striking and damaging the pipeline, but the ship did not pass over the eventual leak location. The *MSC Danit*, however, passed over the pipeline leak location several times while dragging anchor. Therefore, the NTSB concludes that, although both ships' anchors struck, damaged, and displaced the pipeline, the *MSC Danit* anchor's contact with the San Pedro Bay Pipeline was the initiating event that led to the eventual crude oil release.

2.3 Anchorage Location

2.3.1 Background

An anchored vessel is impacted by the winds and seas, thus will move about in its anchorage. This movement is normal if the vessel remains within its drag circle.[42] Dragging anchor is a rare occurrence, particularly in designated anchorages, and it may take time to recognize the condition and take action. To confirm a vessel is dragging anchor, a vessel crew must identify that their vessel's position has moved outside the circle, which may take several minutes. Additionally, a vessel may drag anchor under conditions like those in which the anchor had previously held fast (did not drag). Six days before the January 25 anchor dragging, the *MSC Danit* had been anchored in San Pedro Bay when the area experienced 22- to 35-knot winds with gusts to 43 knots. Neither the *MSC Danit* nor any other vessel dragged anchor during this earlier high-wind event. (The difference between the two wind events, which likely resulted in the different outcomes, was the wind direction: on January 19 the winds were from the northeast—from shore; on January 25, the winds were from the northwest—from the open ocean—generating significantly higher seas).

Only when the crew has determined that the vessel's anchor is dragging and decides to get underway does the crew start the main propulsion engine and heave in the anchor. It then takes time to raise the anchor and get underway, especially for large vessels such as 1,000-foot-long and larger containerships like the *Beijing* and *MSC Danit*. Engineers need to take several steps before starting the slow-speed diesel engine (even if the engines are on standby), which is directly coupled to the

[42] A *drag circle* or *swinging circle* is a circle centered on the anchor drop location and defined by the length of anchor chain that has been payed out plus the distance between the hawsepipe and GPS antenna.

propeller and therefore cannot idle, and crews must also shift engine control to the bridge. Crewmembers also need to standby at the anchor-handling equipment on the bow and prepare to heave in the anchor. (On most ships the anchor-handling gear is exposed to the weather, and ships are not crewed to support continuous presence on the bow.) Readying the ship to heave in the anchor may take 15 minutes or more, even in emergency situations.

Once the crew has begun heaving in the anchor, the process is slow. The *Beijing*'s anchor windlass was rated at a speed of 29.5 feet of anchor chain per minute. At this speed, the ship would have needed 18 minutes to heave in its initially deployed 6 shots (540 feet) of anchor chain under normal conditions, had the windlass not failed. According to an *MSC Danit* master (who was not aboard during the January 25 anchor dragging), the vessel's windlasses were capable of heaving in the anchor chain at a speed of 1 shot (90 feet) of anchor chain every 5 minutes. Thus, under normal conditions, the ship would have required 35 minutes to heave in the 7 shots (630 feet) of anchor chain that were payed out when it arrived in the anchorage. Anchor dragging situations are most likely to occur under severe wind and sea conditions, putting a strain on equipment and increasing the time necessary to heave in the anchor.

Designated anchoring positions must provide a sufficient margin of safety between anchored vessels and any nearby hazards, such as pipelines. The margin of safety must account for the time necessary for a crew to get a vessel underway during an anchor dragging situation. An Army Corps of Engineers permit for the construction of the San Pedro Bay Pipeline required 1,500 feet between the pipeline and Anchorage F, which was established about the same time that the pipeline was under construction in 1980. As originally drawn, the center of the closest anchorage position within Anchorage F (F-16) was 4,230 feet from the charted location of the pipeline, and its outer edge of was 2,430 feet from the pipeline. However, in 2006, the Coast Guard expanded Anchorage F, with its new southeastern border paralleling the San Pedro Bay Pipeline by a charted distance of 180 feet, and added new anchorage positions, including SF-3, with the outer edge of SF-3 at 786 feet from the pipeline's charted location.

2.3.2 January 25 Events

The crew of the *Beijing* began heaving in the ship's anchor at 0405 local time, 11 minutes after they had confirmed that the anchor was dragging. By 0411, 17 minutes after determining that their ship was dragging anchor, the crew had started the main propulsion engine and issued engine orders. However, due to the proximity of the anchorage to the San Pedro Bay Pipeline, the *Beijing* had already drifted over the charted pipeline location. The failure of the anchor windlass motor, which occurred as the main propulsion engine was started, significantly complicated an already difficult maneuvering situation. As the crew worked to hold the vessel's position while troubleshooting the windlass motor, they were further burdened by the presence of the containership *CMA CGM Mexico*, which dragged anchor and moved toward the *Beijing*. At 0630, the *CMA CGM Mexico* requested that the *Beijing* open the distance between the two vessels to avoid collision, which necessitated the *Beijing* moving farther east, past the pipeline.

Within 7 minutes of the *MSC Danit*'s anchor beginning to drag, at 0516 (based on AIS data), the vessel's crew had started the main engine and issued engine orders. The crew attempted to maintain the vessel's position, but it continued to move east in the high winds and seas. When the crew determined that they could not maintain the ship's position, they began to heave in the anchor. However, by this time the ship was already crossing the San Pedro Bay Pipeline. As the *MSC Danit* crew maneuvered to hold position, the tanker *Hong Kong Spirit* began dragging anchor in the *MSC Danit*'s direction. This situation limited the *MSC Danit*'s ability to maneuver forward or heave in its anchor without risking collision.[43] The *MSC Danit*'s situation was further complicated by the maneuvering of the *Beijing* on its port side.

The margin of safety around designated anchorage positions must also account for the size of vessels anchoring. The *Beijing* had been anchored in position SF-12, as assigned by VTS LA-LB. The pipeline's charted location was 2,733 feet from the center and 933 feet from the outer edge of anchorage position SF-12. The length of the *Beijing* was 1,150 feet, and when it arrived in San Pedro Bay, the crew had payed out 6 shots (540 feet) of anchor chain. Thus, when winds were from the northwest, as they were on January 25, the vessel was potentially less than one ship length away from the pipeline even before its anchor began to drag (see figure 26). The *MSC Danit* was likewise within one ship length of the pipeline as it swung at anchor before dragging began.

[43] When a ship heaves in its anchor, the ship moves forward, toward the anchor—even if that anchor is dragging.

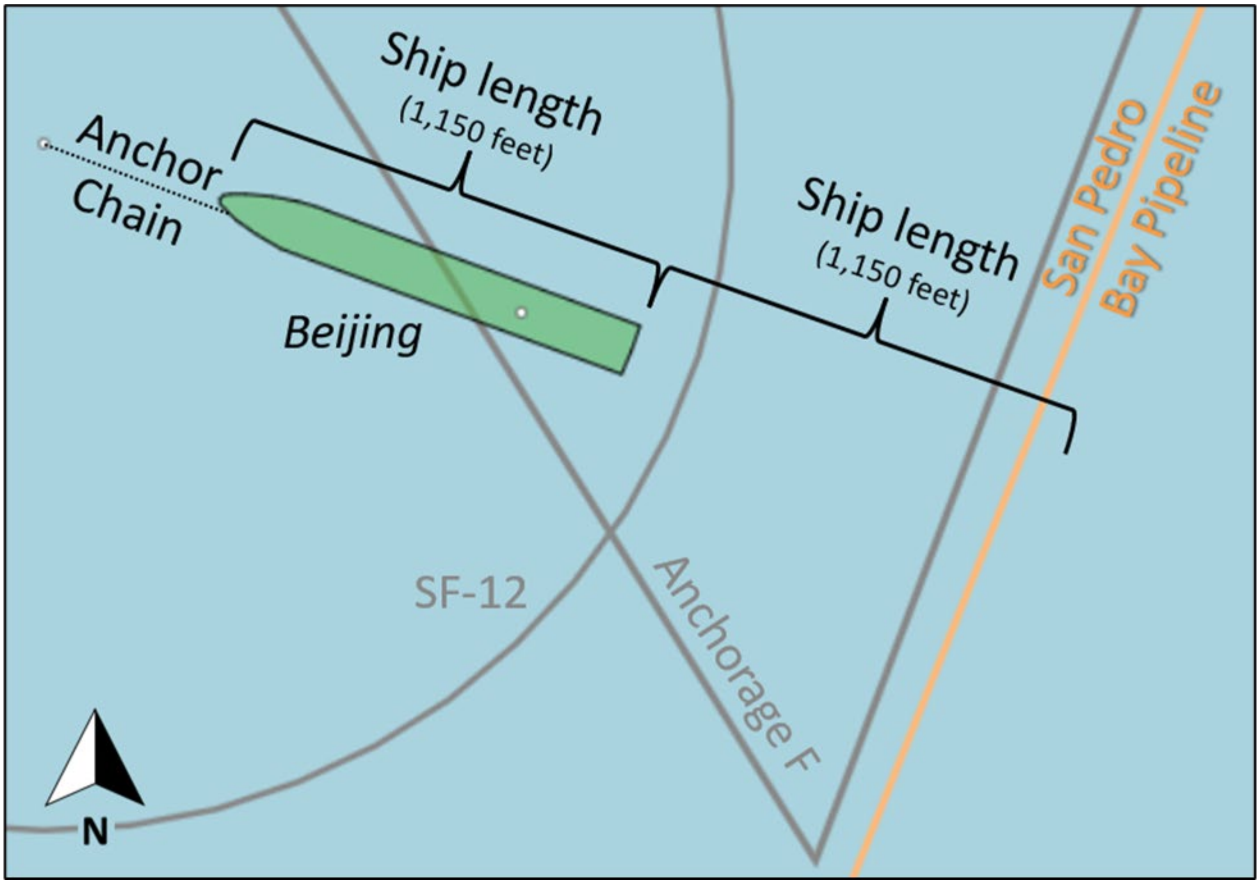

Figure 26. *Beijing* before its anchor began to drag, with less than one ship length between the vessel and the San Pedro Bay Pipeline.

The ships' crews determined that their vessels were dragging anchor, started their main engines (which had been on standby), and began heaving in their anchors in a reasonable amount of time, given the time necessary to confirm their navigation situation, complete the engine starting procedures, and crew the anchor station on each bow. However, once the *Beijing* and *MSC Danit* began dragging anchors, the crews could not heave in their anchors before the anchors struck the San Pedro Bay Pipeline, because of the size of the vessels and distance between their assigned anchorage positions and the pipeline. The NTSB concludes that, because of the proximity of anchorage positions to the pipeline, the crews of the *Beijing* and *MSC Danit* had insufficient time and space to heave in their dragging anchors in high winds and seas before the anchors contacted the pipeline. The NTSB further concludes that the southeast boundary of Anchorage F and the location of contingency anchorage positions southwest of Anchorage F did not leave a sufficient margin of safety between anchored vessels and the San Pedro Bay Pipeline.

After the pipeline leak, VTS LA-LB discontinued use of anchorage positions SF-3 and SF-12, as well as other anchorage positions close to the San Pedro Bay

Pipeline and other pipeline systems. VTS LA-LB also reduced the number of available anchorage positions to increase spacing and reduce risk. Long term, VTS LA-LB has proposed a restructuring of the federal anchorages in San Pedro Bay. The restructuring plan increases the distance between the centers of anchorage positions in Anchorage F and the San Pedro Bay Pipeline to a minimum of 1 mile, well in excess of the 1,500-foot buffer required by the original Army Corps of Engineers construction permit for the pipeline. Given the NTSB's determination that the current anchorage boundaries and contingency positions provide an insufficient margin of safety with the San Pedro Bay Pipeline, the NTSB agrees with VTS LA-LB's anchorage restructuring proposal. Therefore, the NTSB recommends that the Coast Guard implement the proposed VTS LA-LB restructuring of the San Pedro Bay federal anchorages to increase the margin of safety between anchored vessels and pipelines in San Pedro Bay.

2.4 Notification of Pipeline Damage

The release of oil from the San Pedro Bay Pipeline occurred on October 1–2, over 8 months after the ships' anchors struck the San Pedro Bay Pipeline. If damage to the pipeline had been identified immediately after the anchor strikes, Beta could have discontinued use of the pipeline and completed repairs before the leak occurred. Beta's operations and maintenance manual required the operator to repair any condition that adversely affected the safe operation of the pipeline. The NTSB concludes that, had the pipeline operator been made aware of the *Beijing* and *MSC Danit* anchor dragging, the company could have conducted an underwater survey of the pipeline, identified the damage, and made repairs, preventing the eventual release of crude oil. However, Beta was not notified of the anchor dragging events that had occurred on January 25, and therefore had no reason to conduct an underwater survey that would have revealed the damage to the pipeline.

One of the VTS's principal functions is to assist in the safe navigation of vessels through a port, and VTS watchstanders should be able to identify and warn vessels when a potential danger exists, such as the risk of contact with a pipeline. VTS LA-LB watchstanders told investigators that they had been trained on and were aware of the San Pedro Bay Pipeline's location near the anchorage. But VTS LA-LB's area of responsibility spans over 1,000 square miles, and it is not feasible for a watchstander to recall all the area's potential hazards and danger zones from memory alone, particularly during high-intensity operations. At the time that the *Beijing* and *MSC Danit* were dragging anchor, multiple other vessels were dragging anchor, heaving in their anchors, and getting underway. Two vessels, the *CMA CGM New Jersey* and the *Ever Front*, collided when they dragged anchors that morning.

Due to the sheer size of the VTS LA-LB area of responsibility and the number of vessels that must be monitored within the area, VTS watchstanders must have tools available to them to identify hazardous situations. An overlay of the pipeline or a chart layer would have provided the watchstanders with a visual indication of its presence at the time of the anchor-dragging events on January 25, 2021. However, no overlay was available, and nautical chart layers showing pipeline hazards were turned off because of excessive clutter. Watchstanders monitored the vessels' movements, but they did not recognize the hazard presented to the pipeline as the vessels dragged anchor southeast toward the pipeline. Consequently, VTS LA-LB watchstanders provided no warnings of the pipeline to the *Beijing* or *MSC Danit* crews. Following the anchor dragging, VTS LA-LB made no reports to the pipeline operator regarding the potential damage to the pipeline. It is apparent that watchstanders were unaware of the hazardous situation that had occurred. The NTSB concludes that due to the absence of a visual indicator of the San Pedro Bay Pipeline on the VTS LA-LB vessel monitoring system and exceptionally high vessel activity occurring in the anchorage due to the weather, the VTS watchstanders did not recognize the danger presented to the San Pedro Bay Pipeline by the *Beijing* and *MSC Danit* dragging anchors.

Since the oil release, VTS LA-LB has added visual overlays of the San Pedro Bay Pipeline and other pipelines to its vessel monitoring system to assist watchstanders in identifying vessels that may be encroaching on the pipelines. The NTSB believes that additional updates to the system could further enhance safety by increasing watchstander awareness of potential hazards. When the *Beijing*, *MSC Danit*, and other vessels dragged anchor on January 25, the VTS vessel monitoring system alerted the watchstanders to these anchor-dragging events. When a vessel's motion indicated that it was dragging anchor, distinctive audible and visual alarms triggered on the system, and the watchstanders then contacted the vessels. The addition of audible and visual alarms configured to alert when an anchored vessel is encroaching on a pipeline would improve VTS watchstander awareness of a potential incursion, particularly in situations where there is high activity, such as the day of the accident. The NTSB, therefore, concludes that an audible and visual alarm on the VTS LA-LB vessel monitoring system that alerts when an anchored vessel is encroaching on a pipeline would improve watchstander awareness of the possibility of an anchor strike in the San Pedro Bay anchorages. Therefore, the NTSB recommends that MAREX work with its vessel monitoring system provider to add audible and visual alarms to the system that alert the VTS watchstander when an anchored vessel is encroaching on a pipeline. The NTSB further recommends that the Coast Guard develop and implement the capability on all VTS vessel monitoring systems nationwide to provide audible and visual alarms for VTS watchstanders when an anchored vessel is encroaching on a pipeline.

As the *Beijing* and *MSC Danit* departed the anchorage after getting underway on January 25, the crews did not have a positive indication that their anchors had struck the pipeline. The pipeline was marked on the *Beijing* and *MSC Danit*'s electronic navigation charts, which the crews had available to them, but the crews did not know where their anchors had dragged. There is no sensor or indicator on the bridge of a ship providing the anchor's actual location. Under normal conditions, the anchor's location can be assumed to be where it was dropped on arrival, but once an anchor begins dragging, its real location is unknown. Although a broad assumption can be made based on the amount of anchor chain in the water (and even this must be relayed from the crew on the bow—there is not an indicator of anchor chain length on most vessel bridges), a crew that is working to get a vessel underway is not tracking the location of the anchor.

The crews of the *Beijing* and *MSC Danit* had some evidence suggesting that their anchors had escaped an incursion with the pipeline. Foremost, the crews fully retrieved their anchors. Had the anchors not disengaged from the pipeline, the crews would have known that the anchors had hooked it. The lack of pollution was another indicator. Had the pipeline been breached immediately, the incursions by the ships would have been evident by the presence of crude oil in the water.

Under 33 *CFR* 160.216, the owner, agent, master, operator, or person in charge of a vessel must immediately notify the nearest Coast Guard Sector Office or Group Office whenever there is a hazardous condition either on board the vessel or caused by the vessel or its operation. The regulations define a *hazardous condition* as "any condition that may adversely affect the safety of any vessel, bridge, structure, or shore area or the environmental quality of any port, harbor, or navigable waterway of the United States."

Under this regulation, the crews of the *Beijing* and *MSC Danit* would have been required to report the damage to the pipeline, had they known that damage occurred. However, with no evidence of damage, the crews likely did not believe that a hazardous condition had happened, and therefore did not make a report.

As this case demonstrates, the ramifications of an anchor strike on a pipeline may not manifest until long after the strike has occurred. VTS LA-LB watchstanders and the crews of the *Beijing* and *MSC Danit* had information that a pipeline was nearby, and the containerships' proximity alone suggested an anchor strike on the San Pedro Pipeline was, at the very least, a possibility. Had either VTS LA-LB watchstanders or the vessel crews reported the possible incursion and the pipeline operator been informed, the oil release would likely have been prevented. Yet, for the reasons stated previously, the VTS watchstanders and ships' crews were not aware of the dangerous situation that had been created. Thus, an opportunity to prevent the pipeline leak was lost.

As stated earlier, the VTS watchstanders did not recognize the danger presented to the San Pedro Bay Pipeline by the *Beijing* and *MSC Danit* dragging anchors. Even if the watchstanders had recognized the danger, they did not have a procedure for informing Beta of the potential damage. The consequences of a pipeline breach and subsequent oil release to health, safety, and the environment are so great that even the possibility of damage needs to be reported immediately so it can be addressed and environmental damage minimized. Therefore, a system must be in place to inform pipeline operators when any known *or potential* incursion—resulting from an activity such as an anchor strike, contact by a grounded vessel, or dredging—has occurred on an underwater pipeline in ports and waterways.

With incursions on pipelines and other utility lines involving vessels in ports or areas that have a VTS, the VTS is likely the first point of notification, either directly via vessel monitoring systems or indirectly via vessel reporting. VTS watchstanders must be ready and able to communicate information regarding a potential incursion to pipeline or other utility operators so that the operators can check the integrity of their systems. Numerous pipelines and utilities often cross ports and waterways, and ownership and operatorship may differ for each individual line. Attempting to identify pipeline and utility owners and operators and then find their contact information after an incursion has occurred would delay notification and potentially increase harm to the environment. The NTSB concludes that defined procedures for informing pipeline and other utility operators when possible incursions have occurred within the VTS area of responsibility would improve the pipeline or utility operator's ability to identify and respond to any damage. Currently, VTS LA-LB does not have a defined procedure for informing pipeline operators when a possible incursion has occurred, and the NTSB believes that such a procedure should be implemented not only at VTS LA-LB, but in all VTS areas nationwide. Therefore, the NTSB recommends that the Coast Guard develop procedures for VTSs to notify pipeline and utility operators following potential incursions on submerged pipelines and utilities within the VTSs' areas of responsibility.

In the evening on October 1 and early morning of October 2, the NRC received reports of an "oil slick" and an "oil anomaly" that could later be correlated to the San Pedro Bay Pipeline leak. At the time the reports were received, however, the source of the oil was unknown, and therefore the pipeline operator was not informed. The NRC forwarded the reports to the Coast Guard and BSEE, and the agencies made efforts to investigate the reports when assets were available and daylight operations allowed, on October 2. Beta reported the leak before the Coast Guard and BSEE could identify the oil source; therefore, the agencies were not a factor in the discovery.

2.5 Response to Crude Oil Release

2.5.1 Pipeline Controller Actions

The first leak alarm sounded at 1610 on October 1. Beta's procedures directed controllers to isolate their pipeline if a leak was suspected or indicated by the leak detection system. After initial isolation, they were to close additional valves and evaluate whether drawdown of the pipeline was needed. Contrary to Beta's procedures, the pipeline controller on duty stopped the shipping pump about an hour after the first leak alarm and later restarted the shipping pump. The controllers stopped the shipping pump a total of eight times, and about 14 hours passed from the time of the first leak alarm at 1610 until the controllers stopped shipping pumps for the final time, about 0604 the next day.

From the afternoon of October 1 to the early morning on October 2, the controllers received eight leak alarms. The controllers on duty the day of the release reacted to, but did not appear to understand the significance of, the multiple alarms as they went off throughout the night. Instead of shutting down and isolating their pipeline, as directed in their procedures, each time, the pipeline controllers responded to the alarms as if they were false alarms and restarted a pipeline shipping pump.

The controllers eventually implemented their manual leak detection procedure, a procedure that was only to be used in the event of a communication breakdown between Platforms Elly and the Beta Pump Station (there was no such communication breakdown). While the manual leak detection calculation showed a 16- to 20-barrel-per-hour difference between the volume shipped from Platform Elly and the volume received at Beta Pump Station, the pipeline crew still did not isolate their pipeline. They shut down pumps and had a contractor inspect their right-of-way. Because it was still nighttime, the contractor used a spotlight and flashlights to look for oil but didn't find any. Then the controllers restarted the pipeline pumps believing that the alarms were false.

Several factors likely contributed to the pipeline controllers' failure to appropriately respond to the repeated leak alarms:

Water buildup in the pipeline. On October 1, the free water knockout tank, which separated water from an oil/water emulsion, experienced problems that resulted in up to 100 times more water entering the pipeline than normal. The first leak alarm activated shortly after the problem with the free water knockout tank that caused the water buildup was repaired. The dayshift controller said he assumed the alarm was erroneous and activated due to upset conditions in the pipeline from shipping the large volumes of water with the crude oil. Controllers told the NTSB that, throughout the course of troubleshooting the leak alarms, they assumed that many abnormal parameters were due to the excess water in the system.

Leak Location Error. The leak detection system indicated that the location of the leak was at Mile 0, at Platform Elly, instead of displaying the actual location of the leak on the underwater portion of the pipeline. Pipeline crewmembers therefore focused their attention on inspecting the equipment on Platform Elly for a leak. The pipeline controllers sent a crewmember to visually observe the water surface at Platform Elly. Each time, the crewmember confirmed that no oil was on the water at the platform. This further incorrectly confirmed the controllers' initial assumption that the leak alarms were false alarms.

Communication-loss Alarms. The pipeline had a history of experiencing communication-loss alarms, and on October 1, operators received several communication-loss alarms throughout the day. The dayshift controller told the NTSB that, when the leak alarm activated at 1610, he assumed he had received false indications from the equipment. He told investigators that he was "thinking that it was just a regular loss of communication," and "it didn't really dawn on me that it was actually a leak because it happens to us all the time." The NTSB reviewed alarm data and did not find a correlation between communication-loss alarms and leak alarms.

Following the pipeline leak, Beta overhauled the communication networks servicing the platforms and onshore facilities, including investing in three sets of new high-capacity, long-distance microwave radios that increase performance and reliability of network communications.

Automated monitoring systems compare incoming data against set thresholds, and when defined parameters are met, the system activates alarms to alert the controller so they can further analyze and take appropriate action to resolve the alarmed condition. The controller's response is based on their workload, supporting alarm information, system status knowledge, and past experiences. Based on these factors, the controller assesses the reason for the alarm, attributes a cause, and plans action to resolve the alarm.

When the pipeline controllers received the leak alarms, their assessment of the alarms was influenced by the recent water buildup in the pipeline, supporting information erroneously showing that the leak had occurred at Mile 0 on Platform Elly, and recent communication-loss alarms. Because of these factors, the controllers attributed the alarms to anomalies within the system rather than an actual leak. As such, efforts to resolve the alarm centered on resetting the system to address these anomalies delayed identification of the actual crude oil release.

The NTSB concludes that abnormal operating conditions such as water buildup in the pipeline, an incorrect leak location indicated by the leak detection system, and frequent previous communication-loss alarms contributed to the pipeline controllers' incorrect determination that the leak alarms were false.

If the pipeline controllers had isolated the pipeline when the leak was first detected by their leak detection system and thoroughly investigated their system for a leak, they would have reduced the amount of time that the leak persisted. In reducing the response time, they would have consequently reduced the volume of crude oil released.

During a postaccident inspection, PHMSA determined that in the 5 minutes after the first leak alarm was received, about 34 barrels of crude oil had released. This is significantly less than the estimated 588 barrels of oil that leaked from the pipeline during Beta's response that included 14 hours of troubleshooting. Smaller oil spills generally have lesser impact on a given environment. Therefore, the NTSB concludes that had the San Pedro Bay Pipeline controllers responded in accordance with company procedure for a leak by shutting down and isolating their pipeline, they would have significantly reduced the volume of crude oil released and the resulting environmental damage.

According to PHMSA, the operator could not provide any records to demonstrate that it annually simulated emergency shutdown, isolation, and drawdown of the San Pedro Bay Pipeline with its personnel for the past 5 years.

Thus, the controllers did not have experience, even through simulation, with low-probability, high-consequence situations such as a major leak. Many industries that are threatened by low-probability, high-consequence accidents use simulators to provide their operational personnel the opportunity to safely experience these low-probability events and learn how to apply appropriate responses to stop or limit the resulting high-consequence event. In addition, the controllers did not undergo any formal training to help them fully understand the leak detection system.

The pipeline controllers lacked the proper training to react and appropriately respond to leak alarms at the first indication of a leak. This is a consideration for any pipeline control center and has been the topic of a previous NTSB safety study. In 2005, the NTSB completed a study to examine how pipeline operators use SCADA systems to monitor and record operating data and evaluate its role in leak detection (NTSB 2006). As a result of the study, we issued two recommendations to PHMSA:

> Require pipeline companies to have a policy for the review/audit of alarms. (P-05-2, Closed—Acceptable Action)
>
> Require controller training to include simulator or non-computerized simulations for controller recognition of abnormal operating conditions, in particular, leak events. (P-05-3, Closed—Acceptable Action)

In response, PHMSA made significant changes to 49 *CFR* 195.446, which included requirements for alarm management and controller training.

PHMSA outlined in the Notice of Probable Violation for this accident that Beta was not in compliance with control room management requirements. PHMSA determined that Beta did not provide needed training to its controllers, training they needed to have a working knowledge of its pipeline system and safely respond to abnormal operating conditions.

Therefore, the NTSB concludes that the insufficient training of the pipeline controllers contributed to the 14-hour delay in stopping the pipeline's shipping pumps and the increased volume of crude oil released following the first leak alarm. After the accident, Beta committed to PHMSA's proposed compliance conditions, including updating procedures on pipeline start up and shutdown, emergency shutdown and isolation, abnormal operations, and control room management. Beta agreed to provide training simulations on all revised procedures and also agreed to train their employees on fatigue risk management.

2.5.2 Dayshift Pipeline Controller Fatigue

In the time leading up to the first leak alarm, the dayshift controller did not get the amount of rest mandated by company policy, which required that controllers have an opportunity for 8 hours of continuous sleep between shifts. September 30 was the first day of the dayshift controller's 2-week shift on Platform Elly. He told investigators he had about 4 hours and 45 minutes of sleep the night before he arrived at Platform Elly to begin his shift. Although normally pipeline controllers worked 12-hour shifts, the dayshift controller worked from about 0600 on September 30 until about 0100 on October 1—an 18-hour shift—because the other controller was not available. The dayshift controller told investigators that he went to bed about 0200 and then woke up about 0430 for his next shift—only getting about 2 hours of sleep between shifts. The dayshift controller then worked about 13 hours, from about 0500 to about 1800 on October 1, during which time he was busy with the water buildup in the San Pedro Bay Pipeline, spurious communication-loss alarms, and the first two leak alarms.

Given the dayshift controller's extended awake hours, he was susceptible to the performance effects of acute fatigue at the time that the first leak alarm activated. Acute fatigue can occur when individuals receive less than the recommended 7-8 hours of sleep during a 24-hour period. Performance effects of fatigue include diminished alertness, poor decision-making, and a reduction in operator vigilance. The dayshift controller's actions in response to the alarms—assessing the conditions and responding with an action—did not indicate impairment due to fatigue. The experienced nightshift controller was with the dayshift controller when the first and second leak alarms activated, and they concurred on a response and worked together to troubleshoot until the dayshift controller went off duty about 1800 on October 1.

The NTSB concludes that although the dayshift pipeline controller was likely affected by the adverse performance effects of acute fatigue, the incorrect response and assessment of the leak alarms was due to insufficient training of the dayshift pipeline controller and nightshift pipeline controller.

The presence of a third pipeline controller on Platform Elly would have prevented the dayshift controller from having to work an unplanned 18-hour shift when the nightshift controller was unexpectedly not available. Following the pipeline leak, Amplify evaluated staffing levels for each element of its pipeline-related operations. As a result, Beta plans to increase its staffing on Platform Elly to provide for three control operators (an increase of one per crew) and three plant operators (an increase of one per crew) for a testing period of 3 years and then reevaluate their offshore staffing. Additionally, PHMSA's Proposed Compliance Order, if implemented, would require Beta to provide training to all controllers and supervisors on fatigue risk management.

2.6 Drug-testing Deficiencies

The pipeline controllers on duty were not tested for alcohol and other drugs following the oil release discovery. According to Beta, they did not conduct testing because at the time of the release the cause was unknown. Without drug test results, it was not possible to determine whether alcohol or other drug use contributed to the pipeline controllers' actions on the night of the accident. Beta's decision not to conduct required postaccident alcohol and other drug testing resulted in an absence of safety critical information. After the accident, Beta took no actions to improve their drug-testing program and PHMSA did not take exception to Beta's absence of postaccident drug testing. The lack of action from PHMSA on this issue is concerning, as the current accident is not the first time that a pipeline operator's decision not to conduct postaccident testing resulted in the loss of safety-critical information.

After a catastrophic natural gas transmission pipeline rupture and fire in San Bruno, California, on September 9, 2010, the Pacific Gas and Electric Company decided not to perform any alcohol or other drug testing of its control room staff (NTSB 2011). As a result, NTSB issued Safety Recommendations P-11-12 and -13 to PHMSA to amend 49 *CFR* 199.105 and 49 *CFR* 199.225 to eliminate operator discretion for the testing of covered employees, and to issue immediate guidance clarifying the need to conduct postaccident alcohol and other drug testing of all potentially involved personnel despite uncertainty about the circumstances of the accident.

On February 23, 2012, PHMSA issued advisory bulletin ADB-2012-02, "Pipeline Safety: Post Accident Drug and Alcohol Testing," reminding pipeline operators of the need to conduct postaccident alcohol and other drug testing of all potentially involved personnel, despite uncertainty about the circumstances of the accident. On January 23, 2017, PHMSA published a final rule, "Pipeline Safety: Operator Qualification, Cost, Recovery, Accident and Incident Notification, and Other Pipeline Safety Proposed Changes," requiring employees to be tested for drugs after an accident, with an exemption only when there is sufficient information that establishes that the employee had no role in the accident. PHMSA's actions improved the regulations and reminded operators of the need to conduct alcohol and other drug testing despite uncertainty about the circumstances of the accident, thereby addressing the NTSB's recommendations. As a result, both Safety Recommendation P-11-12 and -13 were classified Closed—Acceptable Action. However, as discussed above, even with the advisory bulletin and enhanced regulatory language, Beta did not test the controllers and PHMSA did not address Beta's decision not to conduct postaccident alcohol and other drug testing. Therefore, the NTSB concludes that Beta Offshore was not in compliance with regulations when the company did not drug test the pipeline controllers following the accident. The NTSB recommends that PHMSA audit Beta Offshore's drug-testing program to ensure compliance with postaccident drug-testing regulations.

2.7 Pipeline Safety Management Systems

As of the date of this accident, Beta did not have a formal PSMS program; however, they had some internal programs that overlapped with elements of ANSI/API RP 1173. PSMS is the formal, organization-wide approach to managing safety risk, enhances the effectiveness of risk management, and enables continuous improvement of pipeline safety performance.

A PSMS program can help pipeline operators ensure that pipelines are designed, constructed, operated, and maintained in a manner that complies with federal, state, and local regulations. After this accident, PHMSA conducted a compliance review and identified 10 probable violations of the Pipeline Safety Regulations. In addition to PHMSA's preliminary findings, we found that Beta was not in compliance with regulations when the company did not drug test the pipeline controllers following the accident (see Section 2.6).

A PSMS program includes maintaining procedures that address safe work practices and ensuring personnel follow these written procedures. In this accident, we found that the San Pedro Bay Pipeline controllers did not follow company procedures that required them to isolate their pipeline if a leak was indicated by the leak detection system.

Further, PSMS assists pipeline operators in better ensuring a prompt and effective incident response that minimizes the adverse impacts on life, property, and the environment. This is done, in part, through training and improvements that are developed by incorporating previous lessons learned. However, as stated earlier, we found that the delayed response to this accident showed that previous issues, like communication-loss alarms, as well as insufficient training, contributed to a larger volume release (see Section 2.5.1).

The NTSB believes that the implementation of a robust PSMS program would have helped Beta comply with regulations, ensure employees were following company procedures, and better prepare personnel to respond and react to the conditions found during this release. Therefore, the NTSB concludes that had Beta Offshore implemented a pipeline safety management system, they may have further evaluated their operations, identified continuous improvement opportunities, and better positioned their staff to respond and react to a leak.

The NTSB has long advocated for the implementation of safety management systems that provide an organization-wide approach to managing safety risk in the pipeline industry.[44] We acknowledge that there are several ongoing initiatives encouraging voluntary PSMS implementation and that some operators have implemented such programs. Survey results from PHMSA and the PSMS Industry Team indicated that the majority of pipeline industry mileage, about 85%, is covered by a PSMS. However, as we see in this accident, not all pipeline operators under PHMSA's regulatory authority have implemented a formal PSMS program. Thus, the

[44] The API RP 1173 framework is intended to be scalable and is strongly recommended for pipeline operators of all sizes.

NTSB concludes that pipeline safety would be enhanced if pipeline companies implemented safety management systems. Therefore, the NTSB recommends that PHMSA issue an advisory bulletin to all PHMSA-regulated pipeline owners and operators, promoting the benefits of PSMS and asking them to develop and implement such a system based on API RP 1173.

3 Conclusions

3.1 Findings

1. None of the following issues contributed to the pipeline leak: (1) pipeline as-manufactured material condition; (2) pipeline overpressurization; (3) experience and qualifications of the vessel crews and Vessel Traffic Service (VTS) personnel; or (4) fatigue of vessel crews and VTS watchstanders.

2. Although there were no indications of alcohol or other drug use by the pipeline controllers on duty at the time of the crude oil release or *Beijing* and *MSC Danit* crewmembers on duty at the time of the anchor draggings, evidence was insufficient to determine whether alcohol or other drug use contributed to the pipeline leak and severity of the accident.

3. The release of crude oil occurred as a result of fatigue failure that manifested over a period of time in an area of local deformation to the San Pedro Bay Pipeline caused by an external force applied to the pipeline that resulted in progressive cracks initiating and growing through the pipe wall until the pipe wall ruptured.

4. As a result of the winds and seas generated by a strong cold front, the containerships *Beijing* and *MSC Danit* dragged anchor, and the anchors struck, displaced, and damaged the San Pedro Bay Pipeline.

5. Although both ships' anchors struck, damaged, and displaced the pipeline, the *MSC Danit* anchor's contact with the San Pedro Bay Pipeline was the initiating event that led to the eventual crude oil release.

6. Because of the proximity of anchorage positions to the pipeline, the crews of the *Beijing* and *MSC Danit* had insufficient time and space to heave in their dragging anchors in high winds and seas before the anchors contacted the pipeline.

7. The southeast boundary of Anchorage F and the location of contingency anchorage positions southwest of Anchorage F did not leave a sufficient margin of safety between anchored vessels and the San Pedro Bay Pipeline.

8. Had the pipeline operator been made aware of the *Beijing* and *MSC Danit* anchor dragging, the company could have conducted an underwater survey of the pipeline, identified the damage, and made repairs, preventing the eventual release of crude oil.

9. Due to the absence of a visual indicator of the San Pedro Bay Pipeline on the Vessel Traffic Service (VTS) Los Angeles-Long Beach vessel monitoring system and exceptionally high vessel activity occurring in the anchorage due to the weather, the VTS watchstanders did not recognize the danger presented to the San Pedro Bay Pipeline by the *Beijing* and *MSC Danit* dragging anchors.

10. An audible and visual alarm on the Vessel Traffic Service Los Angeles-Long Beach vessel monitoring system that alerts when an anchored vessel is encroaching on a pipeline would improve watchstander awareness of the possibility of an anchor strike in the San Pedro Bay anchorages.

11. Defined procedures for informing pipeline and other utility operators when possible incursions have occurred within the Vessel Traffic Service area of responsibility would improve the pipeline or utility operator's ability to identify and respond to any damage.

12. Abnormal operating conditions such as water buildup in the pipeline, an incorrect leak location indicated by the leak detection system, and frequent previous communication-loss alarms contributed to the pipeline controllers' incorrect determination that the leak alarms were false.

13. Had the San Pedro Bay Pipeline controllers responded in accordance with company procedure for a leak by shutting down and isolating their pipeline, they would have significantly reduced the volume of crude oil released and the resulting environmental damage.

14. The insufficient training of the pipeline controllers contributed to the 14-hour delay in stopping the pipeline's shipping pumps and the increased volume of crude oil released following the first leak alarm.

15. Although the dayshift pipeline controller was likely affected by the adverse performance effects of acute fatigue, the incorrect response and assessment of the leak alarms was due to insufficient training of the dayshift pipeline controller and nightshift pipeline controller.

16. Beta Offshore was not in compliance with regulations when the company did not drug test the pipeline controllers following the accident.

17. Had Beta Offshore implemented a pipeline safety management system, they may have further evaluated their operations, identified continuous improvement opportunities, and better positioned their staff to respond and react to a leak.

18. Pipeline safety would be enhanced if pipeline companies implemented safety management systems.

3.2 Probable Cause

The probable cause of the damage to and subsequent crude oil release from the San Pedro Bay Pipeline was the proximity of established anchorage positions to the pipeline, which resulted in two containerships' anchors striking the pipeline when the ships dragged anchor in high winds and seas. Contributing to the crude oil release was the undetected damage to the pipeline, which allowed fatigue cracks to initiate and grow to a critical size and the pipeline to leak nearly 9 months later. Contributing to the amount of crude oil released was Beta Offshore's insufficient training of its pipeline controllers, which resulted in the failure of the controllers to appropriately respond to leak alarms by shutting down and isolating the pipeline. Contributing to the pipeline controllers' inappropriate response to the leak alarms was the water buildup in the pipeline, an incorrect leak location indicated by Beta Offshore's leak detection system, and frequent previous communication-loss alarms.

4 Recommendations

4.1 New Recommendations

As a result of this investigation, the National Transportation Safety Board makes the following new safety recommendations.

To the Pipeline and Hazardous Materials Safety Administration:

Audit Beta Offshore's drug-testing program to ensure compliance with postaccident drug-testing regulations. (P-24-1)

Issue an advisory bulletin to all Pipeline and Hazardous Materials Safety Administration-regulated pipeline owners and operators, promoting the benefits of pipeline safety management systems and asking them to develop and implement such a system based on American Petroleum Institute Recommended Practice 1173. (P-24-2)

To the US Coast Guard:

Implement the proposed Vessel Traffic Service Los Angeles-Long Beach restructuring of the San Pedro Bay federal anchorages to increase the margin of safety between anchored vessels and pipelines in San Pedro Bay. (M-24-1)

Develop and implement the capability on all Vessel Traffic Service (VTS) vessel monitoring systems nationwide to provide audible and visual alarms for VTS watchstanders when an anchored vessel is encroaching on a pipeline. (M-24-2)

Develop procedures for Vessel Traffic Services (VTS) to notify pipeline and utility operators following potential incursions on submerged pipelines and utilities within the VTSs' areas of responsibility. (M-24-3)

To the Marine Exchange of Southern California:

Work with your vessel monitoring system provider to add audible and visual alarms to the system that alert the Vessel Traffic Service watchstander when an anchored vessel is encroaching on a pipeline. (M-24-4)

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

JENNIFER HOMENDY
Chair

MICHAEL GRAHAM
Member

BRUCE LANDSBERG
Member

THOMAS CHAPMAN
Member

Report Date: January 2, 2024

Appendixes

Appendix A: Investigation

The National Transportation Safety Board (NTSB) was the lead federal agency for the pipeline accident element of this investigation; the US Coast Guard was the lead federal agency for the marine casualty element. The NTSB was notified of the pipeline leak on October 3, 2021, and two pipeline accident investigators launched to the scene that day. On October 5, when evidence indicated that the pipeline leak may have been caused by anchor strikes from a vessel or vessels, the Coast Guard declared the accident a major marine casualty. The next day, the NTSB launched a marine accident investigator to the scene.

While on scene, investigators collected documentation, interviewed pipeline operators, and toured Vessel Traffic Service Los Angeles-Long Beach (VTS LA-LB). After returning from the scene, investigators interviewed VTS LA-LB watchstanders by phone.

Based on information provided by VTS LA-LB and automatic identification system data, investigators identified two vessels, the containerships *MSC Danit* and *Beijing*, suspected of dragging anchor near the pipeline months before the accident, on January 25, 2021. The vessels were overseas during the on-scene investigation; however, the two containerships returned to the US in October and November 2021. During these port calls, investigators boarded the vessels to collect documentation and interview crewmembers.

The Coast Guard, the Bureau of Safety and Environmental Enforcement, Amplify Energy Corp., MSC Mediterranean Shipping Company S.A., and V.Ships Greece Ltd. were parties to the investigation. The Pipeline and Hazardous Materials Safety Administration also cooperated with the NTSB in the investigation.

Appendix B: Consolidated Recommendation Information

Title 49 *United States Code* 1117(b) requires the following information on the recommendations in this report.

For each recommendation–

(1) a brief summary of the Board's collection and analysis of the specific accident investigation information most relevant to the recommendation;

(2) a description of the Board's use of external information, including studies, reports, and experts, other than the findings of a specific accident investigation, if any were used to inform or support the recommendation, including a brief summary of the specific safety benefits and other effects identified by each study, report, or expert; and

(3) a brief summary of any examples of actions taken by regulated entities before the publication of the safety recommendation, to the extent such actions are known to the Board, that were consistent with the recommendation.

To the Pipeline and Hazardous Materials Safety Administration

P-24-1

Audit Beta Offshore's drug-testing program to ensure compliance with postaccident drug-testing regulations.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.6, Drug-testing Deficiencies. Information supporting (b)(1) can be found on page 82-83; (b)(2) can be found on page 83; and (b)(3) is not applicable.

P-24-2

Issue an advisory bulletin to all Pipeline and Hazardous Materials Safety Administration-regulated pipeline owners and operators, promoting the benefits of pipeline safety management systems and asking them to develop and implement such a system based on American Petroleum Institute Recommended Practice 1173.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.7, Pipeline Safety Management Systems. Information supporting (b)(1) can be found on page 83-85; (b)(2) can be found on page 84; and (b)(3) can be found on page 83.

To the US Coast Guard

M-24-1

Implement the proposed Vessel Traffic Service Los Angeles-Long Beach restructuring of the San Pedro Bay federal anchorages to increase the margin of safety between anchored vessels and pipelines in San Pedro Bay.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.3, Anchorage Location. Information supporting (b)(1) can be found on page 72-74; (b)(2) can be found on page 74; and (b)(3) is not applicable.

M-24-2

Develop and implement the capability on all Vessel Traffic Service (VTS) vessel monitoring systems nationwide to provide audible and visual alarms for VTS watchstanders when an anchored vessel is encroaching on a pipeline.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.4, Notification of Pipeline Damage. Information supporting (b)(1) can be found on page 75; (b)(2) is not applicable; and (b)(3) is not applicable.

M-24-3

Develop procedures for Vessel Traffic Services (VTS) to notify pipeline and utility operators following potential incursions on submerged pipelines and utilities within the VTSs' areas of responsibility.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.4, Notification of Pipeline Damage. Information supporting (b)(1) can be found on page 77; (b)(2) is not applicable; and (b)(3) is not applicable.

To the Marine Exchange of Southern California

M-24-4

Work with your vessel monitoring system provider to add audible and visual alarms to the system that alert the Vessel Traffic Service watchstander when an anchored vessel is encroaching on a pipeline.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.4, Notification of Pipeline Damage. Information supporting (b)(1) can be found on page 75; (b)(2) is not applicable; and (b)(3) is not applicable.

References

API (American Petroleum Institute). 2015. *ANSI/API Recommended Practice 1173, Pipeline Safety Management Systems*. 1st Ed., July 2015, https://www.api.org/~/media/files/publications/whats%20new/1173_e1%20pa.pdf.

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NTSB (National Transportation Safety Board). 2006. *Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines*. Safety Study NTSB/SS-05/02. Washington, DC.

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US Coast Guard. 2020. Sector LA-LB, "Delegation of Captain of the Port Authority for VTS Operations," memorandum, August 13, 2020.

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Casualty type	Contact
Location	San Pedro Bay, near Huntington Beach, California 33°34.20′ N, 118°7.26′ W
Date	October 1, 2021
Time	1610 Pacific daylight time (coordinated universal time –7 hours)
Injuries	None
Property damage	$160 million est.
Environmental damage	588 barrels crude oil est. released from pipeline

NTSB investigators worked closely with our counterparts from **Coast Guard Sector Los Angeles-Long Beach** throughout this investigation.

For more detailed background information on this report, visit the NTSB Case Analysis and Reporting Online (CAROL) website and search for NTSB accident ID DCA22FM001. Recent publications are available in their entirety on the NTSB website. Other information about available publications also may be obtained from the website or by contacting–

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Records Management Division, CIO-40
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