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May 12, 2023

Mr. Dustin Hubbard
Director, Western Region
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration
Department of Transportation
12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

Re: CPF 5-2023-011-NOPV (April 6, 2023)
Beta Response to Notice of Probable Violations

Dear Director Hubbard:

We write on behalf of Beta Operating Company, LLC ("Beta") to respond to the above-referenced Notice of Probable Violations regarding the October 2021 spill event.

Beta shares PHMSA's commitment to ensuring public safety and enhancing pipeline integrity. The record before and after the October 2021 spill shows that Beta takes its regulatory, compliance, and safety obligations seriously. Over many years, Beta operated the San Pedro Bay Pipeline ("Pipeline") safely and consistent with applicable laws and regulations. Beta properly invested in its infrastructure, conducted regular inspections, and kept state and federal regulators up to date. External and in-line inspections of the Pipeline repeatedly showed that Beta maintained the Pipeline in excellent condition.

Unfortunately, on January 25, 2021, two massive container ships dragged their anchors in a "no-anchor" zone across the Pipeline. The anchors damaged and displaced the Pipeline. Yet despite the ships repeatedly crossing the Pipeline's well-known location, nobody informed Beta of these anchor drags. Had the ships, the Coast Guard, or the Marine Exchange (which monitors vessel traffic) notified Beta of the anchor drags, Beta would have inspected the Pipeline via a ROV and made any necessary repairs. No disclosures were made, and months later, on October 1 and October 2, 2021, approximately 588 barrels of oil were released at the point of one of the anchor strikes.

On the night of October 1, 2021, the Beta crew worked diligently and in good faith to troubleshoot what the crew believed were false leak detection alarms. After each leak alarm, crew members acknowledged the alarm, checked the alarm system, turned off the Pipeline, and inspected equipment. The alarm system indicated there was a leak at "mile zero"—*i.e.*, on the platform. As a result, the crew sought to identify a possible leak on the platform, and they inspected pipes, valves, shipping pumps, and meters on the platform. Though the crew could not identify the source of the alarms, they continued their process-of-elimination, good-faith search throughout the night. Once oil was confirmed in the water the morning of October 2, the crew immediately shut down the Pipeline and began notifying the relevant authorities pursuant to Beta's Oil Spill Response Plan ("OSRP").

Instead of deflecting blame to the vessels, Beta immediately went to work as a member of Unified Command (a collaborative response team comprised of Beta employees and government agents) to aid the clean-up. As of March 31, 2023, Beta spent approximately $92.8 million in clean-up efforts, including reimbursement for federal, state, and local clean-up efforts. Further, Beta has accepted responsibility in the areas where Beta fell short the night of October 1, 2021. Beta agreed to plead guilty or no-contest to several state and federal misdemeanor charges. Beta also agreed to pay $12 million in fines to federal and state authorities; paid approximately $3.1 million to 240 claimants under the Oil Pollution Act economic claims process; and reached a $50 million settlement with several putative classes of civil plaintiffs.

Beyond its clean-up and claims-resolution efforts, Beta has shown responsibility in multiple ways. Beta has cooperated with all investigations and agencies interested in learning from this spill, including PHMSA, the National Transportation Safety Board ("NTSB"), the Coast Guard, the Bureau of Safety and Environmental Enforcement ("BSEE"), and various California agencies. Further, Beta used the spill as an opportunity to enhance its procedures, systems, and technology to improve safety and performance. For example, Beta installed a new, state-of-the-art leak detection system and retained a third-party consultant to perform a top-to-bottom review of its existing procedures.

While Beta worked quickly to accept responsibility, the two vessels continued to deny their responsibility for displacing and damaging the Pipeline and for hiding their misconduct. It was not until 17 months after the spill that the vessels agreed to pay Beta $96.5 million for the damages that they caused. In addition, the vessels paid certain insurers tens of millions of dollars and the putative classes of civil plaintiffs an additional $45 million. The $200 million-plus in vessel settlement payments show that the vessels' misconduct caused the spill.

Below, Beta provides additional context about the spill event and Beta's actions before and after it. *See* Part I. In light of the relevant facts and circumstances, Beta contests the alleged violations. *See* Part II. The financial penalty should be withdrawn or substantially reduced because there were no underlying violations, and even if there were, the proposed penalties misapply the required assessment criteria and depart significantly from PHMSA precedent. *See*

Part III. Beta, however, agrees to the proposed compliance conditions, subject to certain clarifications, including that Beta has already implemented some of them. *See* Part IV.

An informal conference is appropriate in the first instance, and Beta believes that PHMSA and Beta can find agreement on the disputed issues. Beta timely files this response to preserve its rights in the event that the parties cannot resolve the matter.[1] Accordingly, PHMSA should delay scheduling any hearing to allow PHMSA and Beta time to convene an informal conference.[2]

Beta appreciates PHMSA's engagement and the opportunity to work productively with PHMSA to address its findings. We look forward to discussing further.

Sincerely,

Christopher W. Keegan, P.C.

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[1] PHMSA granted Beta's request for a one-week extension of this response from May 5 to May 12, 2023.

[2] Pursuant to 49 C.F.R. § 190.211(b), Beta identifies the following "issues that the respondent intends to raise at the hearing," to the extent one becomes necessary in this proceeding: (1) the factual and legal bases for each of the ten alleged violations (Item Nos. 1-10), and (2) the factual and legal bases of the proposed civil penalties, as well as their reasonableness.

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I. Background

A. Pipeline Overview.

The Pipeline has operated safely in the San Pedro Bay for more than four decades. The Pipeline was manufactured in 1979 and installed in 1980. Originating at Platform Elly, a processing platform, the Pipeline is approximately 17.3 miles long. The Pipeline runs through the Long Beach Harbor, terminating onshore at Beta Pump Station[3] in Long Beach.

The Pipeline is buried within the breakwater. Beyond the breakwater, the subsea portion of the Pipeline sits on the ocean floor and always has. The subsea portion of the Pipeline is double submerged arc-welded, cold expanded X52 steel with a 16 in. outside diameter and 0.5 wall thickness. The subsea portion of the Pipeline has a 1-inch-thick concrete coating that weighs 190 pounds per cubic foot. The concrete is applied to weigh down the pipeline to secure it in place. Under the concrete layer, the Pipeline is protected by a double enamel coat system made of coal tar enamel, reinforcing glass wrap, and outer felt wrap. The Pipeline is further protected by sacrificial zinc anodes, which weigh approximately 315 pounds each and are installed at 100-foot intervals.

[3] At footnote 2 on page 2 of the Notice, PHMSA states that the Beta Pump Station "is manned during the day shift, Monday-Friday, by one controller." That sentence is inaccurate and incomplete. The Beta Pump Station is staffed seven days a week, 12 hours per day, by a Pipeline technician, and is otherwise remotely monitored.

Beta operates the Pipeline pursuant to two permits. First, Shell Oil Company, which installed the Pipeline, received a construction permit from the Army Corps of Engineers dated December 11, 1979 (USACE Permit No. 78-178). The permit contains certain conditions, such as maintaining the Pipeline in good condition and allowing periodic inspections. (Other conditions concerned the Pipeline's construction, which Shell completed.) Beta complies with the ongoing conditions by, among other things, operating the Pipeline in a way that poses "[n]o unreasonable interference with navigation" (the Pipeline is marked on nautical charts and located in a no-anchor zone); allowing announced and unannounced inspections by regulators; and obtaining additional permits where necessary (*e.g.*, Beta obtained additional permits for the post-spill repair work).

Second, a Right-of-Way Permit from the Department of the Interior, dated June 29, 1998 (DOI Permit No. OCS-P-0547), allows Beta to conduct "maintenance and operation of a 16-inch outside diameter oil pipeline from Platform Elly to state waters." Beta complies with this permit by, among other things, conducting regular Pipeline inspections (including ROVs, ILIs, and weekly right-of-way inspections); submitting both inspection plans and inspection results to regulators; and maintaining an EHS group and Pipeline Superintendent position to monitor compliance with applicable regulations and permit conditions.

In addition to those permits, Beta also follows all applicable regulations from the Department of Transportation with respect to the Pipeline.

Prior to October 2021, the Pipeline had never leaked in its 40-year-plus history.

B. The Pipeline Sits in a No-Anchorage Zone

Since its original construction, the subsea portion of the Pipeline sits on the ocean floor. The entirety of the subsea portion of the Pipeline is located in a no-anchorage zone, and the risks of anchor-dragging are mitigated through multiple steps.

First, the Pipeline is clearly marked on nautical charts of the area.[4] The nautical charts notify mariners about submarine pipelines, with specific symbols. The charts state, "CAUTION SUBMARINE PIPELINES AND CABLES. . . . Not all submarine pipelines and submarine cables are required to be buried . . . . 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."

Second, the Marine Exchange of Los Angeles-Long Beach Harbor ("Marine Exchange") monitors and assigns vessel anchorages. Vessels are required to stay in their designated anchorages while at anchor, and they are not permitted to drag anchors outside of the anchorage zones or near the Pipeline. If a vessel traveled near or over the Pipeline with its anchor down, Beta expects that the vessel, Marine Exchange, and/or the Coast Guard would inform Beta.

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[4] Beta also maintains a public awareness program that provides information about the Pipeline, including its location, to stakeholders. Beta distributes mailers to emergency officials, public officials, and excavators, among others. The mailers include information on the Department of Transportation's National Pipeline Mapping System. The mailers also explain how to recognize the location of a pipeline and how to keep pipelines safe, including by reporting any suspicious activity or unauthorized excavation.

Third, Beta understands that vessel masters, deck officers, and crew are or should be trained to use designated anchorages; not to assume the designated anchorage area is safe; and not to drag anchors outside of anchorage zones. Further, vessels are required to report marine casualties or hazardous conditions, such as when they drag their anchors in no anchorage zones. If vessels comply with regulatory requirements and training, then no anchors should be drug across the Pipeline or in the right of way. If a vessel violates those regulations or drags anchors, it should inform the Coast Guard, Marine Exchange, and/or Beta.

C. Beta Maintained the Pipeline in Good Condition.

Beta understands that the Pipeline, like all subsea pipelines, is subject to various risks. Beta conducts ROV and ILI inspections on the schedule set by regulators to assess the integrity of the Pipeline and identify changes in its condition. Beta worked hand-in-hand with its regulators to share the results of required inspections and communicate important updates about Pipeline operations. Beta's robust maintenance and inspection schedule for the Pipeline consistently showed the Pipeline was in excellent condition:[5]

- Beta conducted ILIs in 2007, 2009, 2011, 2013, 2015, 2017, and 2019—more frequently than industry standard for undersea oil pipelines.[6] ILI assessments were consistently good and showed no cracks or concerns about the Pipeline's condition. In 2020, because of these positive results, BSEE approved Beta's transition to a four-year ILI cycle.

- Beta conducted either ROV inspections or Side Scan Sonar surveys in even-numbered years (ROVs in 2012, 2014, 2018, and 2020 and Side Scan Sonar surveys in 2010 and 2016). Each ROV report in 2012, 2014, 2018, and 2020 found that the Pipeline was "in good condition with no visible damage or anomalies." The Side Scan Sonar reports from 2010 and 2016 identified some debris near the Pipeline (crab pots, fishing nets, and buoys), which is expected and did not pose a hazard to the safe operation of the Pipeline, but otherwise showed the Pipeline was in good condition.

- Beta also conducted line rides, or visual inspections of the Pipeline's right-of-way. While federal regulations require pipeline operators to conduct ROW inspections every three weeks, and at least 26 times a year, Beta conducted nearly 50 ROW inspections every year from 2010 to present. Each ROW indicated that there was "no free oil or visible floating solids" in the water above the Pipeline.

- Beta has a long history of successful cathodic protection testing on the Pipeline. Annually, Beta works with Farwest Corrosion Control Company to test the onshore section of the Pipeline's cathodic protection by doing rectifier inspections, potential

[5] After the incident, an engineer with the California State Lands Commission (the agency tasked with overseeing pipelines through California state waters) stated: "It's one of the cleanest lines I've ever seen." *See* Michael R. Blood and Matthew Brown, *Aging equipment, spills test ties between oil, California*, AP News (Oct. 14, 2021), https://apnews.com/article/business-environment-and-nature-california-los-angeles-environment-5d441c7842a9b50fde345d415ca3fd53.

[6] Beta conducted two ILIs in 2007.

readings, and current readings of shunts. Throughout the history of the onshore portion of the Pipeline, the cathodic protection system has performed to a level that provides sufficient protection against corrosion. (During ROV inspections, cathodic protection readings are also collected and reviewed.)

- Beta also conducts weekly pigging of the Pipeline and maintains a robust chemical program for it.

Several post-spill assessments also confirmed that the Pipeline was in good condition. ***First***, an October 2021 ROV found the Pipeline to "be in good condition with no visible external damage," with the primary exceptions limited to the anchor-damaged areas (as discussed below).[7] In short, the post-spill ROV confirmed that only those areas where the anchors struck the Pipeline showed signs of external damage that required repair; the rest of the Pipeline remained in good shape.

Second, Beta retained ADV Integrity in March 2022 to perform a third-party review of the Pipeline's ILI data.[8] ADV examined the Pipeline's Magnetic Flux Leakage and Caliper in-line inspection results from 2011, 2013, 2015, 2017, and 2019.[9] ADV's review of the 2019 ILI results concluded that—prior to the anchor strikes—the Pipeline had "zero features representative of third-party mechanical damage near the failure site."[10] The review also concluded that there were "zero indications of third-party mechanical damage elsewhere on the affected pipeline."[11] Further, ADV's analysis of dent and deformation data from the prior ILI reports showed that dents have not significantly increased in size or frequency over time, nor are they concentrated in a particular location along the Pipeline (with the exception of the dents caused by the anchor strikes). In other words, dents discovered along the Pipeline's length (which are limited in number and severity) occurred at random locations at random intervals.

Third, the Pipeline was hydrotested on December 19, 2022. The Pipeline "was successfully held above 2220 psig for a period of 15 minutes with no pressure deviations."[12] The December 2022 hydrotest results show that the the entire Pipeline (including both the undamaged sections and the post-repair anchor-strike sections) remains in good condition.

All of the data available shows that the Pipeline was maintained in excellent condition and if the vessels had not struck the Pipeline, no leak would have occurred.

D. Beta Operated the Pipeline Responsibly.

Beta has a long history of safe operations and strong compliance record.

- Until the April 2023 letters, PHMSA had not initiated any Enforcement Actions against Beta for more than a decade (and none during the period of Amplify's ownership). In

[7] Ex. 1, AMPLIFY-00008398.
[8] Ex. 2, AMPLIFY-00779338.
[9] *Id.*
[10] *Id.*
[11] *Id.*
[12] Ex. 3, AMPLIFY-01335316.

fact, from 2006 to March 2023, Beta received just two warning letters (one in 2008 related to the inspection of main line valves and the pressure setting on two thermal relief valves, and one in 2010 regarding the entry of drug and alcohol testing results into the Management Information System).[13]

- Since 2017, federal regulators conducted 157 inspections across Beta's five California assets (the Elly, Ellen, and Eureka Platforms, Beta Pump Station, and the Pipeline). There were zero facility shut-ins before the spill. Of the 31 incidents of noncompliance ("INCs") since May 2017, 20 were resolved the same day and the others were addressed promptly. The number of INCs has been relatively modest: there were two INCs in 2016, nine in 2017, five in 2018, seven in 2019, four in 2020, and four in 2021.

- Beta has a solid record of minimizing and preventing spills. There were no discharges of over a gallon of oil from any equipment in the Beta oilfield between 2015 and the October 2021 incident.[14]

- Beta's safety performance, as measured by work-related injuries and incidents, is excellent. Between 2018 and 2020, Beta had no "OSHA recordable" incidents. Further, Beta's "Total Recordable Incident Rate," a safety metric that normalizes injury rates among Beta employees and contractors across companies of all sizes, was zero in 2018, zero in 2019, and zero in 2020. In 2020, the American Equity Underwriters, Inc. selected Beta as a safety award winner.

Beta's strong safety record is the result of its significant investments in the facilities. Between 2018 and 2021, the Company spent $6.5 million, $7.7 million, $6.0 million, and $7.2 million, respectively, on Beta facilities and pipeline maintenance and improvements (excluding normal, ongoing maintenance).

E. Beta Had Industry-Standard Policies and Procedures in Place.

Beta's policies and procedures for maintaining and operating the Pipeline—including with respect to leak detection, prevention, and response—were consistent with federal and state pipeline regulations and similar to the policies and procedures employed by other oil pipeline operators.

Beta develops its policies and procedures with third-party consultants and with input from Beta's employees. Beta's policies and procedures are updated per federal and state regulations. Federal regulators audit and/or approve certain procedures.

Beta maintained several policy and procedure manuals relating to operating and maintaining the Pipeline, including: a Hazardous Liquids Operations and Maintenance ("O&M") Manual, which included a Pipeline Specific Operations and Maintenance Manual ("PSOM"); Integrity Management Plan ("IMP"); and the OSRP.

O&M Manual. The O&M Manual contains various policies and procedures relevant to Pipeline operations, including Procedure 1.01 (Reporting and Control of Accidents), Procedure

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[13] In 2008, Beta received two notices to amend certain procedures, which it did.
[14] Ex. 4, AMPLIFY-00749972.

5.02 (CPM and Leak Detection), Procedure 8.01 (Maximum Operating Pressure (MOP)), and Procedure 9.01 (Pipeline Repair Procedures). Beta regularly updates its O&M Manual, including through a full review process every two years. Beta also provides updated copies of its O&M Manual to PHMSA when requested.

PSOM. The PSOM, which Beta updates annually,[15] contains procedures to help ensure that control room operators, pipeline technicians, facility operators, and contractors know how to safely operate and maintain specific sections of the Pipeline and related equipment.[16] For instance, the PSOM includes procedures for the startup and shutdown of the Pipeline; meter proving; launching and receiving cleaning pigs; corrosion monitoring; and emergency shutdown, isolation, and drawdown. The PSOM also requires the submission of a Management of Change ("MOC") form—akin to a safety check-list—for changes to equipment, processes, or operating procedures.[17] The MOC process ensures that the personnel who would be impacted by a change are aware of it and have an opportunity to comment on it.

IMP. The IMP details how Beta monitors and maintains the Pipeline.[18] It requires Beta to develop a baseline assessment method for testing the integrity of the Pipeline, establish repair procedures, and develop preventative measures to mitigate Pipeline risks.[19] Beta conducts risk assessments of the Pipeline pursuant to the IMP. Risk assessments are a multiday process; personnel gather and analyze various data points, including the location of the Pipeline, baseline inspection and maintenance findings for the Pipeline, subsequent historical data and inspection and maintenance results (including ILI and ROV data), and updated or different policies or procedures. The assessments integrate identified risk factors to determine the relevant risk ranking of the Pipeline and the most important factors driving the risk analysis. With assistance from various contractors and personnel, the Pipeline Superintendent completed risk assessments for the Pipeline in 2009, 2011 2016, and 2020. Beta's risk assessments have determined that the risk factors associated with the Pipeline are similar over time because (a) the general location of the Pipeline has not changed, and (b) the results of Pipeline inspections have not meaningfully differed from the results of baseline inspections. Beta also conducted annual evaluations of the effectiveness of its integrity assessment methods and its preventative and risk control activities.[20] The IMP was audited every three years through self-assessment, external audits performed by a third-party contractor, management reviews, and/or agency reviews.[21] The Pipeline Superintendent also reviews the IMP annually.[22]

OSRP. The OSRP designates the personnel in charge of spill response; contains various procedures and checklists for effectively identifying and controlling the source of a spill, monitoring and tracking it, and assessing the risks that it could spread; and identifies the protocol for notifications once a spill estimated to exceed one barrel of oil is verified.[23] To ensure an

[15] NTSB_PHMSA_00000357.
[16] NTSB_PHMSA_00000355.
[17] NTSB_PHMSA_00000419.
[18] NTSB_PHMSA_00004894.
[19] *Id.* at NTSB_PHMSA_00005026–5108.
[20] *Id.* at NTSB_PHMSA_00005090.
[21] *Id.* at NTSB_PHMSA_00005091.
[22] *Id.*
[23] NTSB_PHMSA_00005342; *id.* at NTSB_PHMSA_00005354.

efficient response to a spill, the OSRP also describes the location of relevant response equipment,[24] which Beta inspects monthly and tests semi-annually during equipment deployment exercises.[25]

Beta's policies and procedures are available in electronic form to Beta personnel. Employees are trained on the policies and procedures, as detailed below in Part I(F). While policies and procedures are important, they cannot and do not cover every potential circumstance that operations personnel may confront. Beta expects that its onshore and offshore personnel—and its personnel do indeed—rely on their experience, professional judgment, and training to safely operate the assets in a dynamic environment and respond to unique operating circumstances.

In short, Beta maintained comprehensive procedures that were consistent with industry practice and applicable regulations.

F. Beta Trained its Crews in Line with Industry Practice.

Beta provided its crew with industry-standard knowledge- and skills-based training sufficient to allow them to operate the Pipeline safely, including in detecting, preventing, and responding to potential leaks. Beta has a robust training program for those employees who operate the Pipeline and manage its physical integrity. Employees are trained, certified, and qualified through multiple ways:

First, personnel responsible for operating the Pipeline (as well as operational employees who support daily operations or who provide relief to those who do) participate in a multi-day, T2 training program, also known as Production Safety Systems Training. It covers the use and maintenance of devices and safety systems. Beta also provides monthly T2 and safety refresher courses, which cover a range of safety-operational topics.

Second, Beta regularly trains employees on safety-focused matters, including production safety systems, environmental hazards, and government programs (like the National Pollution Discharge Elimination System). Employees are assigned two to three safety trainings per month. Courses include: (1) Dealing with Hazardous Spills; (2) Accidental Release Measures & Spill Cleanup Procedures; (3) Safety Audits; (4) Accident Investigation; (5) System Troubleshooting; and (6) Emergency Planning, among others.[26]

Third, employees responsible for operating the Pipeline complete operator qualification ("OQ") training modules. Most trainings are completed either annually or once every three years, depending on the course. The online training refers trainees to pre-course reading materials and interactive presentations that employees must complete and refresh within specific intervals. Example OQ trainings include: Pipeline Operations, Control Room Management, Incident Reporting, and Pipeline Emergency Response. Additionally, Beta employees involved in Pipeline operations and who are T2-certified complete certain OQ modules based on their position. For example, T2-certified control room operators complete courses like Abnormal Operating Conditions and Fatigue, among others.

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[24] *Id.* at NTSB_PHMSA_00005893–94.
[25] *Id.* at NTSB_PHMSA_00005894–95.
[26] Ex. 5, AMPLIFY-00155827.

Fourth, Beta conducts monthly "Emergency Drills" with its offshore personnel (one for each crew during its respective 14-day hitch). These drills each cover a specific scenario, including (1) fire and explosion; (2) man down, man overboard, and platform evacuation; (3) terrorism; (4) severe weather; (5) uncontrolled well blowout; (6) hydrogen sulfide and other chemical release; (7) earthquakes; and (8) other scenarios as may be applicable in offshore production operations.

Fifth, Beta trains employees on their responsibilities under the OSRP, spill identification, the spill notification process, and steps to mitigate spills and minimize the potential for environmental damage, among other things. Beta also conducts annual spill-drill training with the crew on duty at the time of the drill. There are other training exercises specific to the Spill Management Team, including quarterly Qualified Individual Notification Exercises and annual SMT Tabletop Exercises. At least once every three years, there is a government initiated unannounced exercise, which tests Beta's ability to respond to a spill.

Sixth, like other pipeline companies, Beta also uses on-the-job training to teach employees the skills needed to successfully operate and maintain their systems, including leak detection systems. Generally, on-the-job training is conducted by in-house experts on a given aspect of work. With respect to control room operators, an operator-in-training works simultaneously with more experienced operators before they are allowed to run "solo" in the control room. Typically, per the MOC process, the most experienced person in the role for which the new employee is training is responsible for conducting and monitoring training and progress of the trainee. On-the-job training does not end when an employee has assumed a new position; on-the-job training is a continual process of self-improvement, as less experienced employees regularly acquire new knowledge and skills by observing and assisting more experienced counterparts every day. The MOC process ensures that employees taking on new roles have the training to perform their responsibilities safely and received direct guidance from more experienced peers

The crew's training was comprehensive and consistent with regulations.

G. Beta Employed an Experienced Crew.

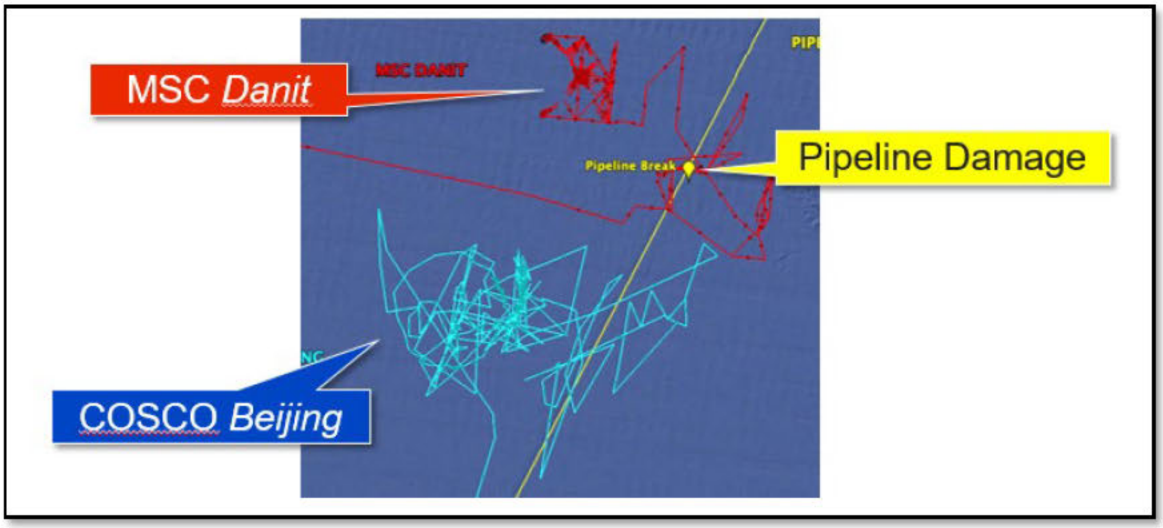
Beta's employees are experienced in offshore oil and gas production. The Platform Superintendent on-hitch on October 1–2, 2021 had been working offshore at Beta since 1998, first as a fire watch, then a crane operator, wellbay operator, lead operator, and project supervisor. One of the two control room operators had worked on offshore platforms for 25 years and had been a control room operator on Platform Elly since 2013; the other had been working for Beta as a control room operator, facility operator, and wellbay operator for 13 years. The Pipeline Superintendent had worked on the Beta assets since 1996, and has been the Pipeline Superintendent since approximately 2014. The two pipeline technicians had been with Beta for eleven and seven years, respectively. In short, the relevant crew had worked the Pipeline and on the platforms for years, and they were well experienced in operating the assets.

H. The Ships Damaged the Pipeline and Caused the Oil Spill.

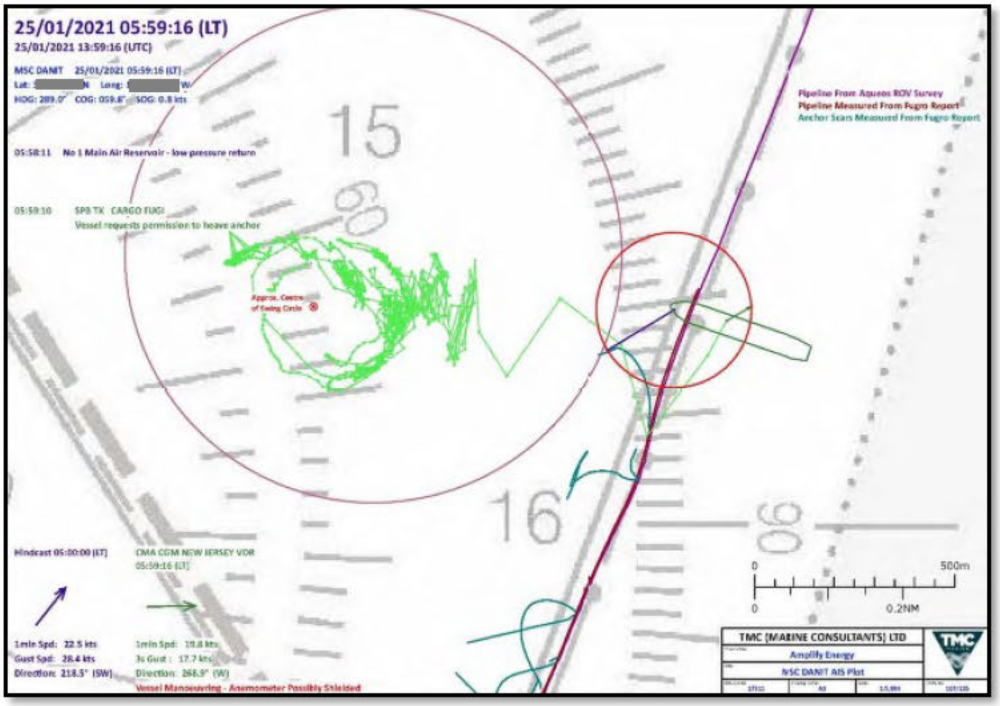
The Pipeline operated safely for four decades. The spill was caused by two cargo ships who drug their anchors over the Pipeline, damaged and displaced the Pipeline, and did not report it. The ships' misconduct bears on the issues and proposed civil penalties in the NOPV.

On January 25, 2021, the MSC *Danit* and the M/V *Beijing* dragged their anchors outside of their designated anchorages and into a "no-anchor" zone across the Pipeline. Both vessels had been warned of an approaching storm, and authorities had instituted "heavy weather protocols." Many other ships left their anchorages to ride out the storm in deeper waters, but the *Danit* and *Beijing* remained anchored near the Pipeline. The storm arrived, and both vessels struggled to control their movements in the high waves and winds. They began dragging their anchors across the seafloor.

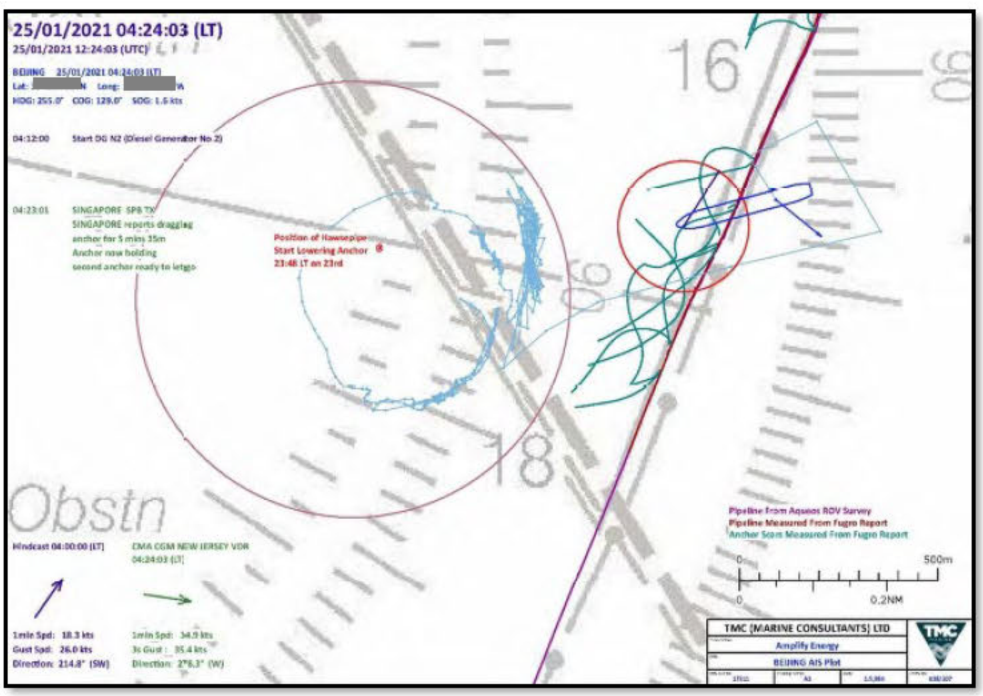
Data sent from the ships' transponders show that they repeatedly zig-zagged across the Pipeline:



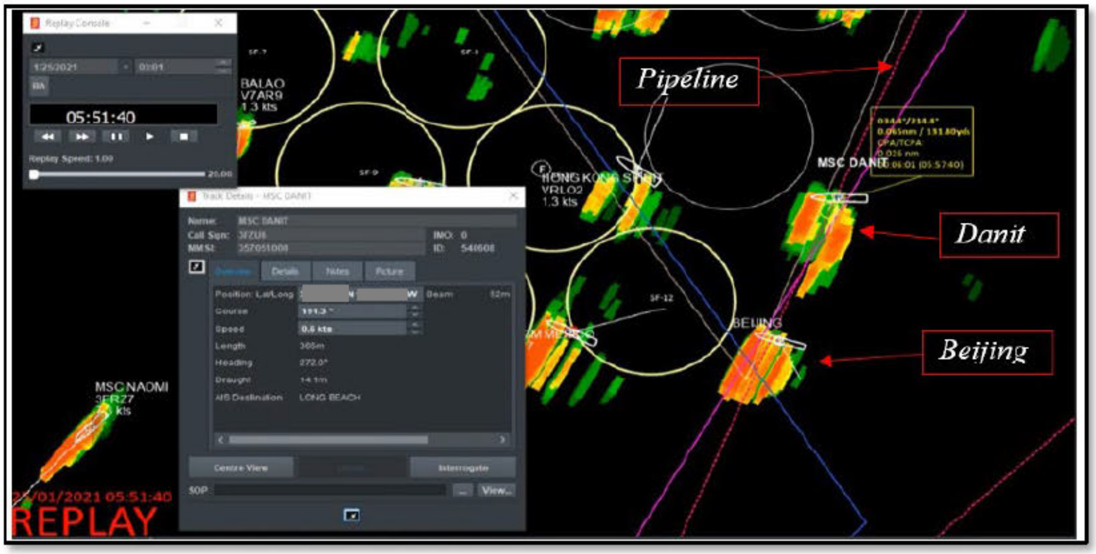
A reconstruction of the *Danit*'s Automatic Identification System ("AIS") data confirmed the vessel's location directly over the Pipeline with its anchor down:



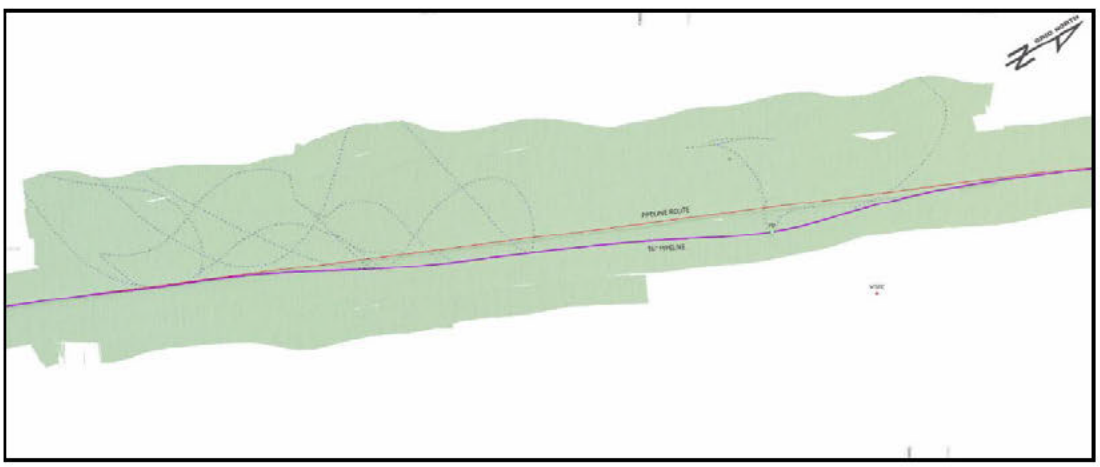
As did a reconstruction of the AIS data for the *Beijing*:



Screenshots provided by the Marine Exchange (which was responsible for monitoring vessel traffic) demonstrated that Marine Exchange also knew, or should have known of the anchor drags over the Pipeline, on January 25:



As the vessels' anchors dragged along the seafloor, they hooked the Pipeline and bent a 4,000-foot section of it. The anchors damaged and displaced the Pipeline by up to 105 feet, stripping off its protective concrete casing in the process. This chart shows both the anchor drags in the sand, the Pipeline's plotted location, and the Pipeline's displaced location:[27]



After an extensive fact and expert discovery process in federal court, the owner of the *Beijing* was forced to admit that "the BEIJING's anchor likely contacted the Pipeline during an anchor dragging incident."[28] Further, the United States has acknowledged that "these anchor drags appear to have occurred, that the anchor drags may have weakened the Pipeline, and that the anchor drags may have been one cause of the oil spill on October 1 and 2, 2021."[29]

Despite the clear evidence of two vessels repeatedly crossed the Pipeline's well-known location while dragging their anchors, nobody—not the vessels, not the Marine Exchange

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[27] Ex. 6, AMPLIFY-00003243.

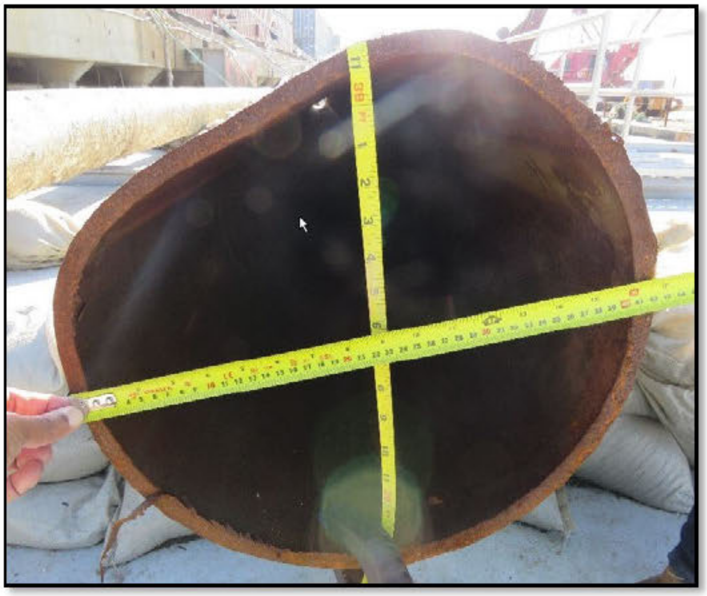
[28] *See In the Matter of the Complaint of Dordellas Finance Corp. Owner and MSC Mediterranean Shipping Company S.A., Owne*r, ECF No. 209 at 4, 2:22-cv-02153-DOC-JDE (C.D. Cal. 2022).

[29] *United States v. Amplify*, ECF No. 42 at 23–24, CR 21-226-DOC (C.D. Cal. 2021).

responsible for vessel traffic, and not the Coast Guard—informed Beta of these anchor drags. The Ship's failure to notify Beta violated federal regulations requiring the vessels to report hazardous conditions and marine casualties created by the ships. *See* 33 C.F.R. § 160.216 (setting requirements for reporting hazardous conditions), 46 C.F.R. § 4.05–10 (setting requirements for reporting marine casualties).

After more than a year of litigation, the vessel owners agreed to a $96.5 million settlement with Beta. The Marine Exchange agreed to certain non-monetary relief, as well. In addition, the vessels paid certain insurers tens of millions of dollars and the civil class plaintiffs an additional $45 million. All in, the vessels paid more than $200 million in civil litigation to resolve claims against them for their misconduct and failure to report it.

Although the Beta crew did not know it on the night of October 1 and the morning of October 2, 2021, the anchors had caused significant damage and displacement to the Pipeline. The following photographs show the bent, deformed, and crushed Pipeline (first at the northern, or *Danit*, anchor contact site, followed by the southern, or *Beijing*, anchor contact site):

The anchor damage caused the spill. Specifically, metallurgical experts, including one retained by the *Beijing*, determined that a fatigue mechanism through cyclic loading caused the initial, *Danit*-caused crack to grow to a through-wall crack and leak on October 1, 2021.

The *Danit* applied a force of about 1,668 kips (where 1 kip=1,000 pounds of force) to the Pipeline. (The *Danit*'s anchor had an unbuoyed weight of about 21.5 tons.) The *Danit*'s anchor caused a global bend along the Pipeline axis above the acceptable standards for safe transport of hazardous liquids. The stresses on the Pipeline, along with the in-line pressure, significantly exceeded the yield strength of the material. Local crushing and deformation along the cross-section also generated significantly high local stresses and strains that resulted in high local stresses that could initiate micro-cracking. And the local deformation, gouges, and denting occurred adjacent to the weld, which contributed to rupture or cracking at the weld-pipe intersection. The *Danit*-caused damage had to be—and was—repaired to return the Pipeline to safe operation.

The damage to the southern, or *Beijing*, section was also substantial. The *Beijing* applied a force of approximately 1,340 kips. (The *Beijing*'s anchor had an unbuoyed weight of about 16.5 tons.) The *Beijing* displaced the Pipeline by about 60 feet. It similarly caused a global bend along the Pipeline axis above the acceptable codes and standards for safe transport of hazardous liquids. The stresses and in-line pressure also significantly exceeded the yield strength at this location. The *Beijing*-caused damage had to be—and was—repaired to return the Pipeline to safe operation.

Had Beta known that an anchor struck the Pipeline and caused the damage shown above, Beta would have suspended operations immediately, deployed an ROV to inspect the Pipeline, detected the Pipeline's displacement, and undertaken remedial actions to prevent a spill from ever occurring.

I. Beta Confronted Various Operational Challenges on October 1–2.

Beta faced various operational challenges on October 1–2 that made it particularly difficult to determine whether the leak detection system was accurately indicating a leak. The record demonstrates that the crew reasonably believed, based on the information available to them and their good-faith troubleshooting, that the leak alarms on October 1–2 were false alarms. Nonetheless, after each alarm, the crew turned off the Pipeline and took steps to determine whether and where the Pipeline might be leaking.

As detailed below, the crew's response was reasonable for at least several reasons:

- ***Pipeline's Good Condition***. The crew had good reason to believe that the leak detection alarms were false alarms because they knew the Pipeline was in good condition; the crew did not know that anchors had damaged the Pipeline; the Pipeline had functioned well for about 40 years; the Pipeline had no history of corrosion or resulting leaks; the Pipeline was regularly cleaned and inspected; and the pressures were relatively normal and below the maximum operating pressure ("MOP").

- ***Mile Zero***. The leak detection system consistently indicated a potential leak at Mile 0 (on Platform Elly), not on the subsea portion of the Pipeline. Given the Mile 0 reading, the crew reasonably focused on locating a potential leak on Platform Elly, including by checking valves, drain lines, pumps, and sumps.

- ***Impact of Operational Upset***. An operational upset on October 1 resulted in upwards of 100 times more water entering the Pipeline during the day on October 1. It was reasonable to expect that this excess water could have impacted the meter and pressure readings on which the leak detection system relied.

- ***Communication-Loss Alarms***. The crew was simultaneously experiencing communication-loss alarms on October 1. The crew believed that communication-loss issues were potentially contributing to the leak alarms. They followed their usual procedures in resetting the leak detection system in response to such communication-loss alarms.

- ***Pig in the Pipeline***. The crew knew that Beta had experienced false leak detection alarms when there was a pig in the Pipeline, as there was on October 1-2, 2021.

* * * * *

Around 8:13 a.m. on October 1, 2021, Beta turned off Shipping Pump P05C in order to load a cleaning pig into the Pipeline. The pig was launched, and P05C was turned back on, around 8:20 a.m. Beta's personnel were aware that there was a pig in the Pipeline throughout the events of October 1–2, and they knew from experience that the pig's movement could create pressure waves in the Pipeline and potentially contribute to or trigger false leak alarms.

Around 11:00 a.m., as part of a separate pigging operation, Beta began to experience an "upset" condition in the processing equipment on Platform Elly. Platform Elly had just received the first of a three-pig chemical train from the 10" intrafield pipeline that connects Platform Elly and Platform Eureka.[30] The three-pig chemical train included a chemical "pill," containing a BT 8415 biocide treatment, that was carried by a K-Disc pig located between a lead brush-cup pig and a trailing Yellow Flex filming pig. Beta's personnel believed that the chemicals "flipped" the free water knockout ("FWKO") tank. Typically, the FWKO tank separates free water from an oil/water emulsion, with oil floating to the top of the tank and water draining from the bottom (which has the effect of reducing the water content of the processing stream that ultimately enters the Pipeline). But because the tank was "flipped," water was at the top of the tank, and was flowing downstream into other processing equipment and, ultimately, the Pipeline.[31]

Beta's personnel spent several hours in the late morning and afternoon of October 1 attempting to resolve the upset condition. The upset resulted in up to 100 times more water entering the Pipeline than normal.[32] The control room operator on duty at the time, Controller 1, contacted the Person-In-Charge, the Platform Superintendent, around 12:30 p.m., to ask for further assistance in resolving the upset.[33] Around 1:30 or 2:00 p.m., Controller 1 and the Platform Superintendent decided to wake Controller 2—an experienced, second control room operator—and Plant Operator, an experienced outside operator.[34] With Controller 2's help, the crew determined that the "water-out" dump valve on the FWKO tank was not operating correctly.[35] This meant that there was an abnormal amount of water exiting the FWKO tank and eventually entering the Pipeline. The upset was eventually resolved around 4:00 p.m., but the crew was aware that there continued to be unusually large amounts of water in the Pipeline on October 1–2.

Beta was also experiencing periodic alarms indicating lost communication between Platform Elly and Beta Pump Station.[36] Platform Elly and Beta Pump Station had historically experienced brief losses of communication; in 2020, Beta invested in a series of replacements and upgrades to the communications systems, which had reduced the frequency of communication issues. But Beta sometimes still experienced communication losses, particularly during foggy weather. In such circumstances, the leak detection system would indicate the loss of communication, and Beta's personnel would shut off the shipping pumps to allow communication to return and to allow the LDS to reset.[37] Beta received communication-loss alarms throughout the day on October 1, including at 3:25 p.m., 3:26 p.m., 3:35 p.m., 4:17 p.m., 4:32 p.m., 5:20 p.m., and 5:29 p.m.[38] Beta's personnel acknowledged these alarms and were aware of the possibility that unstable communications were contributing to or triggering leak alarms.

Around 4:10 p.m., the leak detection system issued a leak detection alarm and indicated a leak location of Mile 0.[39] Controller 1 acknowledged the alarm, which was the first leak alarm

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[30] Controller 1 NTSB Interview Tr. at 15:7–12.
[31] *See id.* at 15:13–16.
[32] Controller 2 NTSB Interview Tr. at 15:19–20.
[33] Controller 1 NTSB Interview Tr. at 16:19–22.
[34] *Id.* at 18:1–8; Controller 2 NTSB Interview Tr. at 15:1–2.
[35] Controller 2 NTSB Interview Tr. at 15:13–14.
[36] Controller 1 NTSB Interview Tr. at 28:11–12, 38:2–5.
[37] *Id.* at 28:6–7.
[38] NTSB_PHMSA_00000069.
[39] *Id.*; NTSB_PHMSA_00015266.

issued on October 1, at 4:11 p.m.[40] Based on the fluctuating hydraulic line conditions that Controller 1 had been experiencing on October 1, including because of the processing upset, Controller 1 reasonably concluded that the 4:10 p.m. alarm was false. Controller 1 and Controller 2 allowed one shipping pump to continue for about an hour, because they believed that, even if the leak alarm was not a false alarm, at minimum it was indicating a leak on Platform Elly, and not on the subsea portion of the Pipeline.[41] Further, the crew was still dealing with the consequences of the high-water upset, knew that high water levels were already in the Pipeline, and believed that continuing to pump would reduce the amount of water pumped into the Pipeline and return the Pipeline to normal operations.[42] The crew also knew that there were operational downsides associated with shutting down the Pipeline, including because once it is restarted, personnel have to manage risks like overpressure, in addition to hazards associated with equipment and hot liquids and surfaces.

During this period, after the first leak alarm, Controller 1 and Controller 2 checked the lambdas generated by the leak detection system and displayed on their HMI screens. The "lambdas" measure the Pipeline's pressure differentials between Platform Elly and Beta Pump Station, as calculated by the leak detection system's proprietary methods.[43] Beta's control room operators knew that increasing lambdas could signal an increasing likelihood of an actual leak. When Controller 1 and Controller 2 noticed that the lambdas had begun rising during the hour that one shipping pump remained on, they conferred and, consistent with their past experience, shut off the shipping pump to allow the Pipeline to settle.[44] Controller 1 and Controller 2 reasonably did not attribute the increased lambdas to a leak, because they knew that the lambdas had a tendency to increase when the Pipeline was shipping oil containing high water content, as it had been for hours at multiples higher than normal.[45] Controller 1 and Controller 2 turned off the shipping pump at about 5:10 p.m., and allowed the Pipeline to settle for about a half-hour, before restarting shipping around 5:40 p.m.[46]

Around 5:52 p.m., the leak detection system issued a second leak alarm, again indicating a leak at Mile 0.[47] Beta's control room operators shut off the shipping pump at about 5:53 p.m., and acknowledged the alarm at 5:56 p.m.[48] Controller 1 and Controller 2 reasonably believed that the second leak alarm was false, particularly given slack line conditions associated with the restart. Given the length of the Pipeline, once the pumps are turned off, it takes a few minutes for oil to stop flowing out of the Pipeline to Beta Pump Station. Similarly, it takes a few minutes for oil to begin flowing into Beta Pump Station after the pumps are turned on. This means that in the minutes after the pumps are turned on or off, the flow and pressure readings at either end of the Pipeline diverge, until the Pipeline returns to steady-state operations. Beta's personnel reasonably

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[40] NTSB_PHMSA_00000069.
[41] Controller 1 NTSB Interview Tr. at 20:15–17, 21:18–21.
[42] *Id.* at 19:19–21, 20:21–22.
[43] *Id.* at 21:7–18.
[44] *Id.* at 21:15–24.
[45] *Id.* at 39:7–12.
[46] NTSB_PHMSA_00000069.
[47] *Id.*
[48] *Id.*; NTSB_PHMSA_00015266.

believed that slack line conditions, which were associated with each start and stop on October 1–2, could be triggering false leak alarms.

Beta's control room operators also reasonably believed, following each leak alarm, that if there were a leak, it was on Platform Elly, and not on the Pipeline. During the time that the pumps were off, Controller 2 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, the Plant Operator checked equipment at Platform Elly, including the PAM units, shipping pumps, and the Pipeline itself.[49] The Plant Operator also put on a flotation device and visually checked the Pipeline down to the point at which it entered the water.[50] At 7:03 p.m., having given the Pipeline over an hour to settle without any active alarms, and having detected no leak on the Platform, Controller 2 restarted one shipping pump.

Around 7:15 p.m., the leak detection system issued a third leak alarm, again indicating a leak at Mile 0.[51] Controller 2 acknowledged the alarm shortly thereafter but reasonably allowed shipping to continue for a short period of time, in order to determine whether the leak detection system would normalize. Beta's personnel continued to believe that they were receiving false leak alarms, particularly because of the leak location reading, the upset condition and its attendant effects (like the abnormally high quantity of water in the Pipeline), the communication-loss alarms, and the presence of a pig in the Pipeline. When the leak alarm did not resolve itself, Controller 2 again shut down the Pipeline.

After the third leak alarm, in addition to directing the Plant Operator to continue checking for a leak on Platform Elly, Controller 2 alerted the Platform Superintendent about the issues that Beta was experiencing with the LDS.[52] They agreed to call the Senior Pipeline Technician who was not on shift at the time, to go to Beta Pump Station to assist in troubleshooting the LDS alarms.[53] The Senior Pipeline Technician then called the Pipeline Superintendent around 7:30 p.m. and informed him that Platform Elly was experiencing issues.[54] The Pipeline Superintendent agreed that the Senior Pipeline Technician should go to Beta Pump Station. The Senior Pipeline Technician arrived at Beta Pump Station around 8:00 p.m. and rebooted the leak detection system.[55] Once the alarms had cleared, at around 8:29 p.m., Beta's personnel reasonably restarted shipping.[56]

Around 8:39 p.m., the leak detection system issued a fourth leak alarm, again indicating a leak at Mile 0.[57] Controller 2 acknowledged the alarm at 8:39 p.m. and turned off the shipping pump at 8:43 p.m.[58] In addition to continuing to check Platform Elly for leaks, and in light of the Mile 0 indication, Beta's personnel also considered whether the programmable logic controllers ("PLCs") at Platform Elly or Beta Pump Station were causing false alarms. Beta's PLCs converted

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[49] Controller 2 NTSB Interview Tr. at 31:2–7.
[50] *Id.*
[51] NTSB_PHMSA_00000069.
[52] Controller 2 NTSB Interview Tr. 29:16–20.
[53] *Id.*
[54] *Id.* at 30:1–3
[55] *Id.* at 35:1–2.
[56] NTSB_PHMSA_00000069.
[57] *Id.*
[58] *Id.*

analog flow measures from the SCADA system's meters into an actual flow rate, by scaling the data. But PLCs, like flow meters themselves, can fail and/or report inaccurate data. The Pipeline Superintendent came to believe that the scaling system could have failed, such that the flow rate was inaccurate. The Pipeline Superintendent therefore texted and called an engineer with the company that supplied and serviced Beta's SCADA system. The engineer eventually confirmed that the scaling appeared to be correct, but not until about 5:30 a.m. on October 2.

In the meantime, Controller 2 and the Senior Pipeline Technician were monitoring the data on their HMI screens, but believed that it appeared to be normal, given the presence of a pig and an abnormal quantity of water in the Pipeline. To continue comparing pressure and flow readings, the pumps had to be on for at least some of the time, and so they reasonably turned one pump on again. Around 9:12 p.m., Controller 2 reasonably restarted one shipping pump to continue troubleshooting, and he switched from PAM A, which Beta had been using, to PAM B to evaluate whether the meter was causing the leak alarms.

Around 9:23 p.m., the leak detection system issued a fifth leak alarm, again indicating a leak at Mile 0.[59] Controller 2 acknowledged the alarm and turned off the shipping pump at about 9:24 p.m.[60] Controller 2 continued monitoring SCADA and HMI data, and personnel further discussed the Mile 0 indication. The Pipeline Superintendent informed the Platform Superintendent and Controller 2 that he believed there could be an open valve or drain line on Platform Elly, and recalled that in the past a one-inch drain line had been accidentally kicked open, resulting in a higher rate out of the meter than was actually being shipped. The Pipeline Superintendent directed Controller 2 to again check the PAM unit for any leaks or open valves, and the Plant Operator assisted in doing so.

The Senior Pipeline Technician also called the Pipeline Superintendent and the two discussed the discrepancy between the flow meters on Platform Elly and Beta Pump Station, with the Pipeline Superintendent indicating that he believed there was either a problem on Platform Elly or false alarms due to the severity of the high-water upset. The Pipeline Superintendent was particularly concerned about the accuracy of the meters given the high quantity of water in the Pipeline. Controller 2 shared the Pipeline Superintendent's concern, particularly because he believed that the pig and the possibility of entrained gas in the system could be exacerbating the line-pack uncertainty that was also heightened by the on-and-off pumping. Eventually, at about 9:44 p.m., having discovered no issues with any meters or valves on Platform Elly, and with the LDS having settled and all alarms having cleared, Controller 2 reasonably restarted one shipping pump to continue troubleshooting the leak alarms.[61]

Around 10:01 p.m., the leak detection system issued a sixth leak alarm, again indicating a leak at Mile 0.[62] Controller 2 acknowledged the alarm at about 10:01 p.m. and turned off the shipping pump at about 10:33 p.m.[63] During the half-hour that he allowed shipping to continue, Controller 2 was concerned about the FWKO continuing to operate incorrectly, as a result of the earlier upset, and wanted to build an oil pad in the tank in order to return the Pipeline to normal

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[59] NTSB_PHMSA_00000069; NTSB_PHMSA_00015266.
[60] *Id.*
[61] *Id.*
[62] *Id.*
[63] *Id.*

operations. During this period, Controller 2 also compared the Pipeline's inlet and outlet pressures, and based on his experience, the difference between the two seemed reasonable.[64] Controller 2 ultimately shut down shipping, as Beta's personnel had after each and every leak alarm, but continued to believe that the LDS was providing false alarms, or else that there was a leak on Platform Elly that the crew had been unable to locate. Controller 2 decided to switch the production stream back from PAM B to PAM A, and also switched shipping pumps, to determine whether either change made a difference. Beta thus reasonably resumed shipping at about 11:15 p.m. in order to continue troubleshooting the leak alarms.

Around 11:30 p.m., the leak detection system issued a seventh leak alarm, again indicating a leak at Mile 0.[65] Controller 2 acknowledged the alarm at about 11:31 p.m., but continued to ship with one pump so that the onshore and offshore crew could conduct a manual leak detection.[66] In a manual leak detection test, the crew measures the flow meter data at each end of the Pipeline, in order to compare the amount of oil shipped from Platform Elly to the amount received at Beta Pump Station. Controller 2 and the Senior Pipeline Technician conducted the manual leak detection test in thirty-minute increments, taking meter readings between about 12:20 a.m. to 2:20 a.m. on October 2, from Platform Elly and Beta Pump Station, respectively.[67]

The manual leak detection readings revealed a difference of about ten barrels of oil between what was shipped from Platform Elly and what was received at Beta Pump Station.[68] The crew believed that this ten-barrel difference could be attributable to factors other than a leak, given the size of the Pipeline, the volume of water in the Pipeline, the pig in the Pipeline, and the possibility of instrument issues and meter inaccuracy. Nonetheless, the crew shut down shipping at the conclusion of the manual leak detection test.[69] Controller 2 and the Platform Superintendent then conferred and decided to order a line ride. Around 2:30 a.m., the Platform Superintendent called SoCal Ship Services, Beta's contractor, to conduct the line ride. Beginning around 3:30 a.m., the *Nicholas L* traced the charted path of the Pipeline, from Beta Pump Station to Platform Elly, and searched for a sign of an oil spill. The pumps stayed off until the *Nicholas L* called the platform and indicated no oil was discovered. After that all-clear from the *Nicholas L*, the crew restarted shipping at about 5:11 a.m. on October 2.[70]

Around 5:28 a.m., the leak detection system issued an eighth leak alarm, again indicating a leak at Mile 0.[71] The crew acknowledged the alarm and continued shipping until about 6:04 a.m., before shutting the Pipeline down to conduct a second line ride in lighter conditions. The *Nicholas L* began a second line ride, after sunrise, around 7:00 a.m., traveling from Platform Elly along the Pipeline, toward Beta Pump Station. Around 8:08 a.m., the crew of the *Nicholas L* informed Beta that it had detected indications of an oil spill, and Beta did not resume shipping thereafter.

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[64] Controller 2 NTSB Interview Tr. at 35:3–10.
[65] NTSB_PHMSA_00000069; NTSB_PHMSA_00015266.
[66] *Id.*
[67] Controller 2 NTSB Interview Tr. at 31:12–32:2.
[68] *Id.* at 32:2–9.
[69] *Id.* at 32:11–14.
[70] *Id.* at 33:10.
[71] NTSB_PHMSA_00000069; NTSB_PHMSA_00015266.

In short, the crew was working diligently and in good faith to troubleshoot what the crew believed were false leak detection alarms. After each leak alarm, crew members acknowledged the alarm, checked the alarm system, shut down the Pipeline, and inspected equipment. Though the crew could not identify the source of the alarms, they continued their process-of-elimination, good-faith search throughout the night.

While the Beta crew was working hard, multiple third parties failed to alert Beta of a potential Pipeline leak on October 1 and 2. Beginning around 5:30 p.m. on October 1, the Coast Guard and Orange County Harbor Patrol Dispatch Center received reports of a possible fuel spill north of the Huntington Beach Pier. Similarly, on October 1, the Orange County Sheriff's Department received calls from residents about a "diesel fuel smell" emanating offshore; the Newport Beach Police Department received around 40 calls between 6:50 p.m. and 11:01 p.m. concerning a "gas smell" in the city. Further, the NOPV states that NRC received a call from a vessel that reported an unknown sheen in the San Pedro Bay at 7:59 p.m. on October 1. And the National Oceanic and Atmospheric Administration discovered a sheen in satellite imagery at around 7:00 p.m. on October 1 and generated a report about "possible oil" at 1:15 a.m. on October 2 (which it shared with NRC).

Beta was left unaware of these reports. None of these agencies alerted anyone on the platforms or at Beta, despite knowing that Beta operated the Pipeline in that area. Had Beta been alerted sooner, Beta would have stopped operations and its troubleshooting efforts and promptly executed its BSEE-approved OSRP. Indeed, when Beta personnel learned of oil in the water at about 8:08 a.m. on October 2, Beta immediately began executing its OSRP and shut down all remaining operations in the Beta oil field, in addition to the already shut-in Pipeline.

J. Beta Reported the Spill Promptly and Took Responsibility.

Once oil was confirmed in the water, notifications were made promptly. Beta personnel contacted Witt O'Brien's and Marine Spill Response Corporation by approximately 8:36 a.m. Pursuant to the OSRP, Witt O'Brien's also called BSEE's California Office of Emergency Services at approximately 8:56 a.m. and the National Response Center at approximately 9:06 a.m.

While notifications were being made, Beta was also helping to stand-up the response and clean-up effort. On October 2, Beta, the Coast Guard, and the California Department of Fish and Wildlife established a Unified Command to clean up and respond to the spill. The Unified Command response was a 24/7 operation supported by the Orange County Sherriff Department's Office of Emergency Services, San Diego County's Office of Emergency Services, and the cities of Long Beach, Newport Beach, and Huntington Beach, among others. Beta funded Unified Command and thoroughly and completely supported the efforts to clean up the spill.[72]

Beta helped ensure a successful clean-up:

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[72] Footnote 15 of the Notice states, "This spill amount was later confirmed by Beta Offshore to be approximately 588 BBLs." In fact, it was the United States Coast Guard who announced on October 14, 2021 that "We have a high degree of confidence that the spill amount is approximately 588 barrels." *See* https://apnews.com/article/oil-spills-business-environment-and-nature-california-environment-94377f4761a614327078cbd6361508f7?utm_medium=AP&utm_campaign=SocialFlow&utm_source=Twitter.

- Within a day of the spill, 14 boats were conducting oil recovery operations, three Coast Guard boats enforced a safety zone around oil recovery vessels, and four aircraft conducted overflight assessments. By October 3, 2021, personnel recovered about 3,150 gallons of oil and deployed 5,360 feet of boom.[73]

- At the height of the response, Unified Command dispatched over 1,800 personnel to aid cleanup operations, working alongside state and federal response personnel and volunteers. Unified Command's large-scale response efforts successfully protected 13 sensitive sites.[74]

- Although several beaches in Huntington Beach, Laguna Beach, Newport Beach, and Dana Point closed briefly, most quickly reopened and some never fully closed at all.[75]

- California reopened all previously closed fisheries on November 30, 2021.

- As of December 27, 2021, Shoreline Assessment and Cleanup teams designated all shoreline segments as returned to their original condition.[76] Unified Command continued to monitor tar ball and oiling incidents through January 2022. On February 2, 2022, with "no further indications of shoreline oiling have been reported since Jan. 4," the Unified Command stood down and concluded its response and monitoring efforts.[77]

Cleanup efforts revealed that other, non-Beta sources of oil were present. Many samples collected during Unified Command's cleanup response did not match Beta's oil. In fact, only six of 265 samples from the most impacted areas—Talbert Marsh, Huntington Beach, and the Santa Ana River Delta—tested as Beta oil. And, as of March 16, 2022, around 57% of tar balls collected and tested did not match Beta's oil.

As of March 31, 2023, Beta spent approximately $92.8 million in clean-up efforts, including reimbursement for federal, state, and local clean-up efforts. In addition to funding the clean-up, Beta accepted responsibility by pleading guilty or no-contest to several state and federal misdemeanor charges and:

- Agreed to pay $12 million in fines to federal and state authorities,

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[73] *See* Unified Command Update 2, S. Cal. Spill Response, at https://socalspillresponse.com/update-2-unified-command-continues-response-to-oil-spill-off-newport-beach/.
[74] Unified Command Deck, Incident Response February 2 Briefing at 4.
[75] *See, e.g.*, *Huntington Beach City and State Beaches to Reopen Monday, October 11, 2021 at 6:00 a.m.*, Huntington Beach Press Release (Oct. 10, 2021), at https://www.huntingtonbeachca.gov/files/users/residents/HB-Beaches-Reopen.pdf.
[76] *See* February 2 Briefing at 10; Unified Command Update 21, S. Cal. Spill Response ("After sustained cleanup operations for the Southern California oil spill, affected shoreline segments have been returned to their original condition."), at https://socalspillresponse.com/update-21-unified-command-concludes-cleanup-operations-of-orange-and-san-diego-county-beaches/.
[77] *See* Unified Command Update 22, S. Cal. Spill Response, at https://socalspillresponse.com/update-22-southern-california-oil-spill-response-moves-into-restoration-phase/.

- Paid approximately $3.1 million to 240 claimants under the Oil Pollution Act economic claims process, and

- Reached a $50 million settlement with several putative classes of civil plaintiffs.

Beta pled guilty or no contest for pumping oil after 1:20 a.m. on October 2, 2021, after the seventh of eight leak alarms. Beta did not plead guilty for—and federal and state prosecutors did not press allegations about—the crew's response to the first six leak detection alarms or any other matter.

Beyond its clean-up and claims-resolution efforts, Beta has shown responsibility in multiple ways, including as discussed in Part I(K) and (L).

K. Beta Cooperated Fully with Investigators.

Beta has cooperated with all state and federal investigations related to the incident. These investigations and the lessons learned from them will make the marine and pipeline industries safer. Beta has cooperated with PHMSA, the Coast Guard, NTSB, BSEE, the Environmental Protection Agency, and various California investigative agencies.

Regarding PHMSA's investigation, Beta interfaced with PHMSA investigators at Unified Command immediately following the spill. Beta facilitated crew interviews by PHMSA, NTSB, and the Coast Guard within days of the spill. PHMSA was also present at Beta's offices during the first phase of Unified Command operations and received real-time access to information. Beta then responded to more than 50 written requests for information and provided PHMSA over 3,300 documents totaling 15,381 pages, plus alarm data and millions of SCADA data points for the Pipeline.

Beta also worked diligently to satisfy PHMSA's October 4, 2021 Corrective Action Order and collaboratively address its questions regarding—and ultimately receive approval for—the temporary and permanent Pipeline repairs. Beta is also grateful for PHMSA's review and approval for Beta's restart plan for the Pipeline last month.

L. Beta Has Enhanced its Policies, Procedures, and Operations.

Beta has used the incident as an opportunity to enhance its policies, procedures, and operations—to promote safety and operational excellence. Specifically:

Revised Procedures. As part of its commitment to learn from the oil spill, Beta retained Eagle Energy Services, LLC ("Eagle") to perform a top-to-bottom review of Beta's existing procedures and propose improvements. An Eagle consultant conducted a desktop evaluation of procedures for Beta's operations of the offshore facilities. As part of that evaluation, the consultant spent time offshore engaging directly with platform personnel. Ultimately, Eagle recommended—and Beta implemented—revisions to Leak Detection (Section 5.02), Abnormal Operating Conditions (PSOM 17.08), and Emergency Response Procedures (PSOM 17.09), among others.

Changes to Pipeline-Related Technology and Equipment. Beta has installed a new, state-of-the art leak detection system from Krohne. Major pipeline operators like BP, Shell, and

Chevron use Krohne's technology. Krohne's new platform and the new interface system allows for increased automation, customization, and use of platform-related data, enabling control room operators to better identify and assess potential issues on the platform and with the Pipeline. The new leak detection system cost about $375,000, excluding the costs of other related improvements, some of which are highlighted in the following bullets.

Changes to Platform-to-Shore Communication Infrastructure. Beta leveraged the operational downtime to complete a major overhaul of the communication networks servicing the platforms and on-shore facilities. These improvements addressed the major network hardware components that connect the offshore platforms to land, including upgrades to critical communication ISP circuits, core network switches, secondary access switches, firewalls, fiber optics, wireless technologies and network automation. Beta also installed three sets of new high-capacity, long-distance microwave radios that increase performance and reliability of network communications. These investments totaled approximately $180,000. As part of a separate, but related project, Beta also invested in a new SCADA HMI system.

Other Enhancements. Other technology and equipment enhancements include:

- The automation and commissioning of a second processing train to facilitate safer platform operations by creating redundant systems and allowing greater vessel residence time of produced fluids.

- Enhancing the platform's overboard incident protection and response systems to minimize spill incidents.

- Adding several Variable Frequency Drives to assist with fine-tuning shipping rate control leaving the platform.

Beta's enhancements demonstrate its commitment to safe operations, and they weigh against imposing additional penalties and terms of compliance.

M. The Spill was an Isolated Incident for Beta.

The October 2021 spill was the first such incident from the Pipeline, or any Amplify-run operation, and it is not representative of Beta / Amplify or its operations, which have no pattern or history of wrongdoing. Beta has not been found to have engaged in any similar wrongdoing by any federal or state agency, or court. Instead, Beta's record is one of safety and responsibility. In short, the spill is an isolated incident that Beta took great care to remedy at great expense.

II. BETA DID NOT COMMIT ANY VIOLATIONS OF THE PIPELINE SAFETY REGULATIONS.

In light of the background above, and for the reasons detailed below, Beta contests each of the ten alleged violations.

A. Item 1: Spill Notification (§ 195.52(b))

Beta contests Item 1. It alleges that Beta "failed to notify" NRC "at the earliest practicable moment following discovery, but no later than one hour after confirmed discovery of a failure that resulted in oil being released."

The evidence contradicts Item 1 and demonstrates that there was no such violation. Notifications were promptly made to the appropriate authorities as soon as oil was confirmed in the water the morning of October 2. Specifically, SoCal Ship Services, a contractor working at Beta's request, discovered the oil spill around 8:08 a.m. on October 2. After offshore personnel shut-in any remaining production (the Pipeline was already off) and made internal notifications that were consistent with the OSRP, Beta notified the Incident Commander at Witt O'Brien's, Beta's designated spill-response contractor, at about 8:27 a.m. Witt O'Brien's then contacted the NRC at about 9:06 a.m., within an hour of the "confirmed discovery" of the oil spill.

PHMSA wrongly suggests that the "confirmed discovery" occurred the afternoon of October 1, following the first leak detection alarm at 4:10 p.m. on October 1. The evidence contradicts that contention several ways, and the crew reasonably believed there was no such leak for various reasons.[78]

First, the Pipeline was in good condition, and Beta did not know that anchors had damaged the Pipeline in two places. The crew had good reason to believe that the leak detection alarms were false alarms, given that they knew the Pipeline was in good condition and unlikely to be leaking and the pressures were relatively normal and below the MOP. The control room operators knew that cleaning pigs were used weekly, that the Pipeline had cathodic protection, and that the Pipeline was regularly inspected by ROV, ILI, side-scan sonar, and line rides. They knew that it was marked on nautical charts and located in a no-anchorage zone. The crew also knew that the Pipeline had functioned well for about 40 years, with no history of corrosion or resulting leaks.

Second, the leak detection system consistently indicated that the leak was at Mile 0, indicating a leak on Platform Elly and not between Platform Elly and the Beta Pump Station.[79] Given the Mile 0 reading, the crew reasonably focused on locating a potential leak on Platform Elly, including by checking valves, drain lines, pumps, and sumps.[80] The crew might, for example, have accidentally kicked or left open a valve, as had in fact happened previously.[81] Given the crew's knowledge that the Pipeline was in good condition and unlikely to be leaking, it was reasonable for the crew to focus on troubleshooting on Platform Elly.

Third, earlier in the day on October 1, Platform Elly had experienced an "upset" condition that resulted in upwards of 100 times more water—a mixture of oil and water comprised of about 50% water, rather than the usual 0.5% water—entering the Pipeline.[82] For the reasons noted

[78] Although the Notice identifies certain spill reports the night of October 1, Beta was unaware of these reports and there is no evidence that anyone contacted Beta at any time about them. None of these agencies alerted anyone on the platforms or at Beta, despite knowing that Beta operated the Pipeline in that area.
[79] Controller 2 NTSB Interview Tr. at 47:7–9.
[80] *See, e.g.*, *id.* at 31.
[81] Controller 1 NTSB Interview Tr. at 77:1–3.
[82] Controller 2 NTSB Interview Tr. at 15:19–20.

below, it was reasonable for the operators to expect that this excess water could have impacted the meter and pressure readings on which the leak detection system partially relied. The increased water content meant the shipping pumps were having to pump at a higher-than-normal rate to clear the dry tank because they were pumping water in addition to oil. The upset also introduced meter uncertainty because the meters were not calibrated to measure a mixture that contained so much water. It also meant that the Pipeline contained unknown amounts of gases entrained in the oil, which could have further affected meter accuracy.[83] All of this uncertainty was also on top of the usual line pack uncertainty caused by changes in temperature and pressure as the oil left Platform Elly at approximately 184 degrees and cooled roughly to the sea temperature during its 17.3-mile trip to Beta Pump Station.[84] Beta's control room operators understood that all of this, in turn, affected the reliability of the SCADA data on which the leak detection system relied. Therefore, Beta personnel reasonably considered the upset condition and its implications in responding to the leak detection alarms on October 1–2.

Fourth, for part of the event, Beta was simultaneously experiencing loss of communication alarms, suggesting that the leak detection system's leak detection alarms might have been unreliable.[85] A loss of communication between the instruments supplying inputs to the leak detection system, even once communication was restored, could induce false alarms. Historically, during periods of communication loss, Beta employees had been able to shut down and restart shipping pumps to reset the LDS, and then resume normal operations. On October 1, Beta experienced communication loss alarms at, for example, 4:17 p.m., 4:32 p.m., 5:20 p.m., and 5:29 p.m.[86] The crew reasonably believed that the communication-loss issues on October 1–2 were potentially contributing to the leak alarms. They followed their usual procedures in resetting the leak detection system in order to restore communication. The LDS ultimately regained communication, but the crew reasonably considered the communication losses as a factor in troubleshooting the leak detection alarms.

Fifth, Beta had a pig in the Pipeline between Platform Elly and Beta Pump Station.[87] The presence of the pig, the pressure required to push the pig through the Pipeline, and the transients created by the pig, especially as the pumps stopped and started, could have further impacted the pressure readings on which the leak detection alarms were based. The controllers understood that Beta had experienced false leak detection alarms when there was a pig in the Pipeline, and they therefore reasonably considered the effects of a pig in the Pipeline in interpreting and troubleshooting the leak detection alarms in the dynamic situation on October 1–2.

All of these circumstances combined to give the Beta crew a reasonable basis to question the accuracy of the leak alarms. While the crew questioned the accuracy, they responded and reacted to each of the alarms on October 1 and October 2. The record is consistent that the crew reasonably believed, based on the information available to them and their good-faith troubleshooting, that the leak alarms on October 1–2 were false alarms. The crew therefore engaged in good-faith troubleshooting efforts throughout the night, turning off the Pipeline after each alarm and attempting to determine whether the Pipeline was actually leaking and, if so, where

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[83] Pipeline Superintendent NTSB Interview Tr. at 57:2–5.
[84] Controller 2 NTSB Interview Tr. at 17:16–18; Pipeline Superintendent NTSB Interview Tr. at 15:8–12.
[85] Controller 1 NTSB Interview Tr. at 67:10–15; *see also* NTSB_PHMSA_00000069.
[86] NTSB_PHMSA_00000069.
[87] Controller 1 NTSB Interview Tr. at 14:9–15.

the leak was located. Despite the crew's best efforts, personnel ultimately did not learn of the oil spill until about 8:08 a.m. on October 2, after oil was detected by SoCal Ship Services, which was doing a line ride at Beta's instruction. Upon that discovery, the crew promptly initiated its OSRP, and the required notifications were made.

Finally, PHMSA wrongly suggests there were 83 leak detection alarms. There were eight alarms, as the United States agreed in the plea agreement. It is unclear how PHMSA tallied 83, although it appears to be based on a misreading of the SCADA tags, in that PHMSA may be relying on the 10_ALM_Leak_Detect_From_Atmos tag. The relevant leak detection tag from the ATMOS system is 14_ALM_Atmos_Leak_Detected.[88] This alarm sounded nine times on October 1–2, 2021, although one of those alarms sounded at a time that the Pipeline's shipping pumps had already been turned off (around 10:33 p.m. on October 1).

B. Item 2: Operating the Pipeline (§ 195.401)

Beta contests Item 2, which alleges that Beta operated the Pipeline "at a level of safety that was lower than required."

On the night of October 1, 2021, the Beta crew worked diligently and in good faith to troubleshoot what the crew believed were false leak detection alarms. After each leak alarm, crew members acknowledged the alarm, checked the alarm system, turned off the Pipeline, and inspected equipment. The crew's response was reasonable for at least several reasons:

- ***Pipeline's Good Condition***. The crew had good reason to believe that the leak detection alarms were false alarms because they knew the Pipeline was in good condition; the crew did not know that anchors had damaged the Pipeline; the Pipeline had functioned well for about 40 years; the Pipeline had no history of corrosion or resulting leaks; the Pipeline was regularly cleaned and inspected; and the pressures were relatively normal and below the MOP.

- ***Mile Zero***. The leak detection system consistently indicated a potential leak at Mile 0 (on Platform Elly), not on the subsea portion of the Pipeline. Given the Mile 0 reading, the crew reasonably focused on locating a potential leak on Platform Elly, including by checking valves, drain lines, pumps, and sumps.

- ***Impact of Operational Upset***. The upset on October 1 resulted in upwards of 100 times more water entering the Pipeline. It was reasonable to expect that this excess water could have impacted the meter and pressure readings on which the leak detection system relied.

- ***Communication-Loss Alarms***. While Platform Elly and the shore were ultimately able to remain in close communication, during part of the events on October 1, the crew was simultaneously experiencing communication-loss alarms. The crew believed that communication-loss issues were potentially contributing to the leak

[88] NTSB_PHMSA_00000069.

alarms. They followed their usual procedures in resetting the leak detection system in response to such communication-loss alarms.

- ***Pig in the Pipeline***. The crew knew that Beta had experienced false leak detection alarms when there was a pig in the Pipeline, as there was on October 1–2, 2021.

All of these circumstances combined to give the Beta crew a reasonable basis to question the accuracy of the leak alarms. The record demonstrates that the crew reasonably believed, based on the information available to them and their good-faith troubleshooting, that the leak alarms on October 1–2 were false alarms. Nonetheless, after each alarm, the crew turned off the Pipeline and took steps to determine whether and where the Pipeline might be leaking. Beta contests PHMSA's suggestion that Beta operated the Pipeline at a lower level of safety that night.

To support Item 2, PHMSA attempts to fault Beta for (i) temporarily putting the leak detection system in "sleep mode" and (ii) performing manual leak detection.

First, placing the system in "sleep" mode does not "stop" the system or equate to "ignoring" it. Rather, the crew still receives and acknowledges the alarms, but the loud ringing is paused. By using sleep mode, the operators—who continue to acknowledge and respond to the alarms—can more easily discuss the alarms and their troubleshooting efforts without the distraction of loud ringing.[89] It is thus misleading to suggest that, by putting the leak detection system in sleep mode, the Beta crew was not attentive to the leak alarms or the possibility of an oil spill, or that they were not working hard to troubleshoot the alarms. Regardless, there is no evidence that Beta failed to receive or acknowledge a leak alarm during the period in which the leak detection system was purportedly in sleep mode. Controller 2 said that the Pipeline was in sleep mode between about 9:15 p.m. and 9:45 p.m.[90] The SCADA data shows that Shipping Pump P05A was restarted around 9:12 p.m., the leak detection system issued a leak alarm at 9:23 p.m., the controller acknowledged the alarm at 9:24 p.m., and the controller shut off the shipping pumps at 9:24 p.m.[91] The controller restarted Shipping Pump P05A around 9:44 p.m., received another leak alarm at 10:01 p.m., and acknowledged the alarm at 10:01 p.m.[92] There is no evidence that placing the leak detection system in "sleep" mode impacted the response and evaluation of the leak alarms in any manner. PHMSA has not connected the temporary "sleep" mode to any additional unsafe operations.

Second, Beta did not operate the Pipeline at a lower level of safety by conducting manual leak detection from about 12:20 a.m. to 2:20 a.m. on October 2.[93] Manual leak detection is an appropriate tool to use when the efficacy of the automated leak detection system is in question. A manual leak detection analysis provides additional information to control room operators about the conditions of a pipeline. In a manual leak detection test, Beta's crewmembers track flow meter data at each end of the Pipeline to monitor the volume of crude oil being pumped into the Pipeline at Platform Elly and the volume arriving onshore at the end of the Pipeline, every thirty minutes, to determine if there is an imbalance that suggests a leak. In the circumstances, conducting manual

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[89] Pipeline Superintendent NTSB Interview Tr. at 56:9–15, 57:10–15, 58:3–4; *see also, e.g.*, *id.* at 56:15–16.
[90] Controller 2 NTSB Interview Tr. at 46:1–20.
[91] NTSB_PHMSA_00000069; NTSB_PHMSA_00015266.
[92] *Id.*
[93] *See* NTSB_PHMSA_00000069; Controller 2 NTSB Interview Tr. at 31:8–32:4.

leak detection was a prudent step for the crew to take as part of their good-faith troubleshooting efforts.

While the SPBPL 16" Manual Leak Detection procedure provides that manual leak detection should be conducted "[i]n the event of a communications breakdown between Platform[] Elly and the Amplify Pump Station,"[94] that does not mean that manual leak detection is never appropriate absent a communications breakdown. The crew conducted manual leak detection as part of their good-faith troubleshooting, and doing so was appropriate in the circumstances. Specifically, during the troubleshooting efforts, the Pipeline Superintendent came to believe that the Pipeline's scaling system could have errored and there could be inaccuracies in the conversion from the PLC (which converted the analog flow meter measurement into the flow rate). While Beta's SCADA provider eventually confirmed that the scaling was working correctly, it was not able to do so until about 5:30 a.m. on October 2, long after the manual leak detection had concluded. Given the circumstances, it was reasonable for Beta to conduct manual leak detection, and it does not support PHMSA's contention that Beta operated the Pipeline at a lower level of safety.

Further, the leak detection system was continuing to operate. The controller had information from that system available and was seeking to supplement the available information, in light of the "Mile 0" reading and the fact that the crew had repeatedly confirmed there was no leak at the platform. PHMSA has not connected the manual leak detection—with the leak alarm running in the background and the crew actively troubleshooting and evaluating a variety of information available to them—with any specific unsafe operations.

C. Item 3: Written Procedures (§ 195.402)

Beta contests Item 3, which alleges that Beta failed to follow specific provisions in five procedures.

As an initial matter, Beta prepared and followed a manual of written procedures for handling abnormal operations and emergencies, in accordance with 49 C.F.R. § 195.402. The Notice does not allege that Beta failed to prepare "written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies," or that Beta failed to prepare such procedures "before initial operations of a pipeline system commence." *See id.* Nor does the Notice allege that Beta failed to review the procedures "at intervals not exceeding 15 months" and "at least once each calendar year." *See id.* The procedures contained in Beta's O&M Manual and the PSOM Manual, when combined with on-the-job training provided to experienced personnel—and supplemented with other training resources—provided sufficient guidance to Beta personnel to safely operate and maintain the Pipeline, including with respect to leak detection, prevention, and response. *See* Parts I(E) and I(F), among others. Indeed, the Pipeline operated safely for decades.

Procedure 17.05. Beta followed Procedure 17.05 *Pipeline – Start Up and Shut down of 16" SPBPL*. The Notice alleges that Beta failed to follow the procedure "by not immediately shutting down the San Pedro Bay Pipeline when it received two [] leak alarms." As discussed in

[94] NTSB_PHMSA_00015523.

great detail in Part I(I), as well as in response to Item 1 and Item 2, the Beta crew's good-faith troubleshooting of the leak alarms does not establish a violation of Procedure 17.05, let alone § 195.402. Considering the totality of these circumstances, it was reasonable for the Beta crew to attempt to troubleshoot the leak alarms and identify a potential leak, rather than to immediately and indefinitely shut down the Pipeline. In any event, all of the alarms were promptly acknowledged, and the Pipeline was shut down in response to each one.[95]

Emergency Shutdown. For the same reasons and in light of the same circumstances described in great detail above, Beta did not violate its *SPBPL 16" Emergency Shutdown, Isolation and Drawdown* procedure.[96]

Procedure 1.01. Beta followed Procedure 1.01 – *Reporting and Control of Accidents*. The Notice alleges that Beta's Pipeline Superintendent and HSE Supervisor failed to notify the NRC of the oil spill "not later than 1 hour following the time of such confirmed discovery." But, as explained in response to Item 1, Beta did notify the NRC—through its spill response contractor, Witt O'Brien's—within an hour of the spill's discovery. That reporting structure is not only allowed, but it is also sensible because it permits the operational personnel to focus on other spill-response efforts (like applying negative pressure on the Pipeline to reduce further release).

Procedure 5.02. Beta followed Procedure 5.02 – *CPM and Leak Detection*. The Notice alleges that Beta violated Procedure 5.02 by allegedly failing to provide control room operators with training contemplated by API RP 1130. Section 6.6 of the most recent edition of API RP 1130 provides, in turn, that the "users of the CPM system and any CPM support staff require appropriate CPM training," and identifies various "technical areas" that "may be considered (only as they relate to the CPM system)."[97] Neither API RP 1130 nor Section 5.02 requires Beta to provide its control room operators with training in all of the technical areas that the Notice identifies, provided the control room operators were adequately trained in leak detection. As discussed in Part I(F) and in response to Item 8, the Beta controllers were. The controllers—who had decades of combined relevant experience—received significant knowledge- and skills-based training on how to operate the Pipeline safely, including with respect to leak detection, prevention, and response. Specifically, Beta required its employees to complete a variety of knowledge- and skills-based training, including three-day T2 trainings, one-day T2 refreshers, OQ trainings, Job Performance Evaluations, online safety training, and emergency drills. And like other pipeline

[95] Beta also did not violate § 195.402 based on the timing of its internal notifications of leak alarms. While it is true that the control room operator did not call the Platform Superintendent until about 7:15 p m. on October 1, the Notice does not (i) acknowledge the Platform Superintendent's involvement earlier in the day or during subsequent alarms; (ii) the involvement of multiple other employees, including the Pipeline Superintendent; or (iii) give sufficient weight to the combined decades of relevant experience from the control room operators.

[96] Regarding the allegation that Beta did not provide evidence that it complied with the *Emergency Shutdown* procedure's directive to "[a]nnually simulate this process in this procedure and review with all personnel that could possibly be involved," the Notice stops short of contending that Beta violated § 195.402. It would not be a violation. That section requires an operator to "prepare and follow for each pipeline system a manual of written procedures," which Beta did. Regardless, on March 18, 2022, Beta responded to Request No. 32 by producing Job Performance Evaluations for its control room operators, bearing Bates Nos. NTSB_PHMSA_00004811 to NTSB_PHMSA_00004893, as well as training records bearing Bates Nos. NTSB_PHMSA_00004543 to NTSB_PHMSA_00004560. *See* Mar. 18, 2022 Ltr. from C. Keegan to D. Hubbard. Those records are indicative of Beta's training on the requirements of the *Emergency Shutdown* procedure, and Beta thus disagrees that it did not provide records to substantiate its compliance with the training requirements of the *Emergency Shutdown* procedure.

[97] API RP 1130 (2d ed.) § 6.6. The NOPV's references to § 6.5 likely refer to an older edition of API RP 1130.

operators, Beta supplemented its knowledge-based training with on-the-job training to teach controllers the skills needed to successfully operate and maintain the Beta systems, including the leak detection system. "Time in the chair" (*i.e.*, experience by doing) is critical, and both Controller 1 and Controller 2 had thousands of hours of relevant experience in the Platform Elly control room that helped them develop and hone the skills necessary to operate and troubleshoot equipment, including the leak detection system. Regardless, the crew's good-faith troubleshooting on October 1–2 in response to the operational challenges the crew faced does not suggest that Beta's training was inadequate, let alone that it violated Section 5.02 or § 195.402.[98]

Procedure 17.08. Finally, Beta followed Procedure 17.08 – *Abnormal Operation*. The Notice alleges that Beta failed to provide evidence that it had implemented Procedure 17.08's requirement to review "personnel response" to an abnormal operating condition and to include consideration of the "actions taken, and whether the procedures followed were adequate for the given situation."[99] The Notice again stops short of affirmatively alleging that Beta actually failed to conduct periodic reviews in response to abnormal operating conditions. Section 195.402 requires an operator to "prepare and follow for each pipeline system a manual of written procedures," and Beta disagrees that a mere failure to furnish evidence of periodic reviews contemplated in a particular company procedure constitutes a violation of that section. Nonetheless, on March 18, 2022, Beta responded to Request No. 30 by referring to records demonstrating that its O&M Manual and Emergency Response Plan were regularly reviewed and revised. Additionally, the kinds of periodic reviews of operator responses to abnormal operating conditions happen regularly, in the ordinary course operations. Beta also incorporates its response to Item 5, regarding the multiple ways in which Beta monitors controller activities: annual performance reviews, PIC hitch turnover notes, and daily safety meetings, among other things. Beta therefore disagrees that it has failed to substantiate its compliance with the periodic review requirement in Procedure 17.08, much less that its alleged failure to do so constitutes a violation of § 195.402.

D. Item 4: Control Room Management Procedures (§ 195.446)

Beta contests Item 4, including for reasons discussed above in response to Item Nos. 1–3. As with Item 3, the Notice does not allege that Beta failed to prepare and maintain procedures that implemented the requirements of 49 C.F.R. § 195.446. Indeed, Beta maintains a 62-page Control Room Management procedure, which is specific to managing the San Pedro Bay Pipeline.[100] It includes subsections titled Roles and Responsibilities, Controller Information, Fatigue Management, Alarm Management, Management of Change, Operating Experience, Training,

[98] The Notice misstates the record by claiming that "controllers continually shut the shipping pumps on and off . . . without performing additional actions to investigate the cause of the leak alarms." In fact, as detailed in Part I(I), various crew members were engaged throughout the evening in investigating potential sources of a leak on Platform Elly, in checking meters at Beta Pump Station, in calling a contractor to conduct a line ride, in contacting Beta's SCADA provider about a possible metering issue, in switching flow rate meters, and in taking numerous other steps to troubleshoot the leak alarms and identify a potential leak. The fact that control room operators had previously and successfully "reset" the Pipeline by shutting off the shipping pumps in response to communication-loss and leak alarms, and that their attempts to do the same on October 1 were unsuccessful, is also not indicative of a failure to train. The Notice does not establish any violation of § 195.402 premised on an alleged violation of Section 502.
[99] *See* NTSB_PHMSA_00000402 at NTSB_PHMSA_00000403.
[100] NTSB_PHMSA_00000637–98.

Compliance Validation & Deviations, and more.[101] Rather, similar to Item 3, the Notice contends that Beta violated its control room management procedure in four respects. Beta disputes each allegation, and Beta did not violate § 195.446.

Procedure 304. The Notice alleges that Beta's control room operators failed to record shift-change information, and that Beta did not provide evidence that its controllers complied with that requirement of Procedure 304. The Notice conflates several distinct requirements of Procedure 304. First, it requires that "[a]t the change of each shift at least one outgoing controller will brief the incoming control room personnel on the current conditions and any upcoming events affecting the operation of the pipeline."[102] There is no dispute that Beta's control room operators complied with this requirement, as the Notice acknowledges that "during the NTSB Interviews, the controller stated that the shift change briefing is done verbally." Second, Procedure 304 requires control room operators to use "form #304 . . . or equivalent (Shift log Book) to document shift change information."[103] The Notice alleges that, because the shift change briefing was done orally, and Beta did not provide copies of Form #304, Beta failed to follow Procedure 304. But, in fact, control room operators documented information—including but not limited to the information listed in Procedure 304—in the red book on Platform Elly. For instance, for October 1–2, the log book contains details about the pig in the Pipeline ("Launched 16" pig to BPS @ 08:31 PAM # 81630"); about the pigs in the 10" intrafield pipeline ("Eureka launched 3 10" pigs"); the upset condition ("trouble with trains with 3 pig w/ chemical batch" and "not able to get rid of wet oil is S02B, having to shutdown wells on Eureka & Ellen"); the first line ride ("SPBPL run start 0400 end 0510 all is ok vessel"); the second line ride ("Nicholas L. started pipeline run @ 06:10 / 7:30[,] found leak @ 08:18 near our pipeline"); and the initiation of the spill response plan ("started to call all spill respon[s]e agencies @ 08:30"); among other details.[104] The red book includes the information that Procedure 304 requires and is an appropriate and functional "equivalent" to Form #304. Regardless, there is no indication—and the Notice does not allege—that any issues with shift-change documentation contributed to the oil spill. Beta thus did not violate Procedure 304, let alone § 195.446(b).

Section 500. The Notice alleges that Beta violated this section by permitting Controller 1 to work 22.5 hours across September 30 and October 1, despite what PHMSA alleges is a stated maximum of 18 hours, and by then permitting him to begin a new shift a few hours hours later. Beta appreciates that, due to a catastrophic wildfire that restricted the ability of Controller 2 to travel from his home to Long Beach, Controller 1 worked long hours during that window. But there was no violation. As Section 500 recognizes, the "[l]imitations can be exceeded under extenuating circumstances," provided the deviation is approved consistent with Section 108.[105] Section 108, in turn, provides that a Beta supervisor "may approve deviations to this manual, but only if the deviation does not relax this manual's requirements below those required by the applicable federal or state pipeline safety regulations."[106] These types of deviations and coverage decisions are assessed based on real-time circumstances and discussed in the ordinary course with

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[101] *Id.* at NTSB_PHMSA_00000637–39.
[102] *Id.* at NTSB_PHMSA_00000651.
[103] *Id.*
[104] *See* Excerpts of Control Room Log, September 24 through October 4, 2021.
[105] NTSB_PHMSA_00000637 at NTSB_PHMSA_00000659. Although Section 500 refers to Section 107, the Deviation and Exception Process is outlined in Section 108, as the Notice recognizes.
[106] *Id.* at NTSB_PHMSA_00000643.

the Platform Superintendent. Regardless, there was no violation of § 195.446(d)(1) or (4). The former requires an operator to "[e]stablish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep." Beta did so, and the Notice does not allege otherwise. The latter requires an operator to "[e]stablish a maximum limit on controller hours-of-service, which may provide for an emergency deviation from the maximum limit if necessary for the safe operation of a pipeline facility." Again, Beta did so.

Procedure 608-2. The Notice next alleges that Beta failed to annually review its alarm management plan. Procedure 608-2 requires that the "Elly Control Room Operator, Elly Facilities Operator, Sr. Pipeline Tech, Pipeline Superintendent and personnel knowledgeable in this area" review the "written alarm management plan for safety related alarms and notifications" at least once each calendar year, to "determine the effectiveness of the plan."[107] The Notice maintains that Beta failed to conduct this annual review, solely on the grounds that the documents Beta provided in response to PHMSA's request "failed to demonstrate that the Elly Control Room Operator, Elly Facilities operator, and Sr. Pipeline Tech had reviewed its Alarm Management Plan." Yet, Beta provided PHMSA with its Alarm Management Plan, Appendix A-601 to the Operations and Maintenance Manual,[108] as well as Beta's annual review documentation, with the Pipeline Superintendent's signature and the date of his review of the entire Manual—including the Alarm Management Plan.[109] The Notice nonetheless takes issue with the fact that Beta did not provide documentation showing that control room operators, facility operators, and/or pipeline technicians signed off on the review process. In fact, other employees, including on-shift control room operators, participate with the Pipeline Superintendent or the instrument technicians in the review, for example a point-to-point / verification testing. The absence of their signatures is insufficient to establish a violation of Procedure 608-2. And it does not establish a violation of § 195.446(e)(4), which requires an annual review, which Beta did.

Section 1002. Beta complies with the requirement in § 195.446(e)(2) by regularly evaluating its alarm and safety equipment, but does not maintain monthly records of these activities, as such records are not required.[110] Any deviation from Section 1002's documentation provision does not constitute a violation of § 195.446(e)(2), which requires only that an operator "[i]dentify at least once each calendar month points affecting safety," but says nothing of required documentation.

E. Item 5: Monitoring Controllers' Responsibilities (§ 195.446)

Beta contests Item 5. Beta did, in fact, monitor the activities and activity levels of its controllers at appropriate intervals. Beta does so through multiple steps:

- ***Annual Performance Reviews***. Beta employees, including controllers, undergo an annual performance review, where employees identifies their accomplishments and goals and supervisors provide employee-specific, written feedback.[111]

[107] NTSB_PHMSA_00000637 at NTSB_PHMSA_00000681.
[108] NTSB_PHMSA_00000636.
[109] NTSB_PHMSA_00004561.
[110] *See* Apr. 1, 2022 Ltr. from C. Keegan to D. Hubbard.
[111] The scope of control room operators' responsibilities have not appreciably changed over time.

- ***PIC Hitch Turnover Notes***. When a two-week hitch ends, Beta's Platform Superintendent drafts a lengthy, day-by-day summary of offshore activity during the hitch. The Platform Superintendent provides his "turnover" notes to Beta's VP of Operations and the off-hitch Platform Superintendent.[112] In addition to summarizing the hitch, these turnover notes highlight personnel-specific activity, including of controllers. Further, Beta staggers its platform superintendent and controller hitches, such that a platform superintendent on a two-week hitch spends one week with the "red team" controllers and one week with the "blue team" controllers. This overlap facilitates monitoring of controller activity and assessments of their performance and activity levels relative to their off-hitch counterparts.

- ***Redbooks***. The controllers record daily events and activities in the control room redbook, which the PIC and management review from time to time.

- ***Daily Safety Meetings***. At 6:00 a.m. each morning, the Beta crew convenes a meeting, attended by the offshore personnel and Beta's VP of Operation, to discuss operational and safety issues. (Further, every Tuesday and Friday at 7:30 a.m., there is a production meeting. The controllers attend those meetings and advise on what is feasible based on existing workloads.)

- ***Monthly Pipeline Summaries***. Each month, the Pipeline Superintendent prepares a "Pipeline Key Activities" document. It summarizes notable events relevant to the operation of the Pipeline (among other assets). This summary is distributed to the shoreside management and control room operators, among others. It includes information about controller activities, like pig launching.

- ***Training Drills***. Controller performance is also assessed in the various training and drills that are summarized in Part I(F).

Thus, Beta followed its written control room management procedure, which implements the requirements of 49 C.F.R. § 195.446 to "monitor the content and volume of general activity being directed to and required of each controller" and to "assure controllers have sufficient time to analyze and react to incoming alarms."

With this response, Beta is providing additional supporting documentation to show how Beta monitored controller activity levels according to the bullets above. On the existing record, however, there was no violation because § 195.446(a) merely directs operators to "have and follow written control room management procedures that implement the requirements of this section." Beta had both the procedure (No. 608-3 – Controller Activity Review) and appropriate oversight. Further, there is no indication that the control room operators lacked sufficient time to analyze and properly act on incoming alarms on October 1–2, 2021. Indeed, the SCADA data demonstrates that the control room operators acknowledged each leak alarm and engaged in reasonable, good-faith efforts to troubleshoot the alarms, with the assistance of other Beta personnel, as summarized above. Nonetheless, even if Beta did not follow the letter of the documentation provisions in its

[112] *See, e.g.*, Ex. 7 - AMPLIFY-00680050.

internal procedure, Item 5 should be reassessed in light of the additional supporting documentation provided herewith.

F. Item 6: Defining Roles and Responsibilities (§ 195.446)

Beta contests Item 6. Focusing on the Pipeline Superintendent, Item 6 alleges that Beta "did not define in its CRM procedures the roles, responsibilities and qualifications of others who have the authority to direct or supersede the specific technical actions of controllers."

The Pipeline Superintendent's roles, responsibilities, and qualifications are detailed in several documents, including an internal job description for the position, Section 19.00 and Form 18.00-7 of the O&M, and Beta's OSRP. (Given the steadiness of the position at Beta—the current Pipeline Superintendent has held the role for a decade—the Pipeline Superintendent's roles and responsibilities are also well known within the organization.) The Pipeline Superintendent's overall role and responsibility is to ensure the safe operations of all pipeline and pump station related facilities and equipment.[113] As such, the Pipeline Superintendent must—and does—understand the fundamentals of gas and liquid pipeline transportation, hydrocarbon measurement, and pipeline-related instrumentation. Further, the Pipeline Superintendent is also involved in routine Pipeline checks and assists with Beta's successful corrosion monitoring program. The Pipeline Superintendent is also responsible for Beta's Pipeline-related compliance with federal and state regulations. To ensure Beta complies with federal and state regulations, the Pipeline Superintendent is involved in compliance-related tasks, such as: (1) drafting and revising Beta's O&M manual as applicable;[114] (2) monitoring ROW surveillance, ROVs, ILIs, and Pipeline repairs; and (3) tracking OQ training, among other things.[115] In addition, the Pipeline Superintendent leads Beta's Public Awareness efforts,[116] and is a designated Qualified Individual and Incident Commander under Beta's OSRP.[117] Regarding qualifications, the Pipeline Superintendent must have a high school diploma and possess 10 years of direct experience with gas and liquid hydrocarbon transportation operations and operating equipment.[118] The Pipeline Superintendent more than meets these requirements: he has worked in the oil and gas industry since 1982 and has been with the Beta assets for 27 years, including almost ten years as the Pipeline Superintendent. Given his deep experience with the Pipeline, Beta employees are aware that, if they have questions or concerns about Pipeline operations, the Pipeline Superintendent is an excellent resource, as he was the night of October 1, 2021, as detailed in Part I(I).

Regarding PHMSA's allegation about "sleep mode," Beta incorporates its response to Item 2. Placing the system in "sleep" mode does not "stop" the system or equate to "ignoring" it. Rather, the crew still receives and acknowledges the alarms, but the loud ringing is paused. By using sleep mode, the operators—who continue to acknowledge and respond to the alarms—can more easily discuss the alarm and their troubleshooting efforts without the distraction of loud ringing.[119] The Beta crew was attentive to the leak alarms and the possibility of an oil spill at Mile

[113] Ex. 8, AMPLIFY-00765189.
[114] *See* NTSB_PHMSA_00000637 at NTSB_PHMSA_00000641.
[115] *See also id.* at NTSB_PHMSA_00000694.
[116] *See* NTSB_PHMSA_00000456.
[117] *See* NTSB_PHMSA_00005342 at NTSB_PHMSA_00005348.
[118] Ex. 8, AMPLIFY-00765189.
[119] Pipeline Superintendent NTSB Interview Tr. at 56:9–16, 57:10–15, 58:3–4.

0, and they worked hard to troubleshoot the alarms. Regardless, there is no evidence that Beta failed to receive or acknowledge a leak alarm during the period in which the leak detection system was purportedly in sleep mode, as demonstrated by the timeline laid out in response to Item 2. There is no evidence that placing the system in "sleep" mode impacted the response and evaluation of the leak alarms in any manner. PHMSA has not connected the temporary "sleep" mode to any additional unsafe operations.

G. Item 7: Fatigue Training (§ 195.446)

Beta contests Item 7, which alleges that Beta did not conduct periodic fatigue training for controllers and control room supervisors who were present at the time of the failure.

Beta complied with 49 C.F.R. § 195.446(d). Beta educated control room operators in fatigue management and trained them how to recognize the effects of fatigue, including the two controller room operators on duty during the October 1-2, 2021 event. They did so consistent with Beta's Control Room Management procedures, which state that controllers must take fatigue training once every three years.[120]

Controller[121]	CRM01 - CRM (Includes Fatigue)	CRM02 - Fatigue
Controller 1	4/13/2018 4/25/2019 10/10/2021 9/12/2022	8/25/2019 10/10/2021 9/12/2022
Controller 2	8/5/2014 4/8/2016 2/8/2019 1/10/2020 10/14/2021 9/14/2022	8/4/2014 4/8/2016 2/8/2019 1/10/2020 10/14/2021 9/14/2022

In addition to formal training, fatigue awareness is also raised in Beta's monthly, employee safety newsletters[122] and then discussed on an as-needed basis with specific individual employees in light of their specific circumstances. Further, the controllers have more than three decades of offshore experience combined. Controller 2 had worked on offshore platforms for 25 years and had been a control room operator on Platform Elly since 2013; Controller 1 had been working for Beta as a control room operator, facility operator, and wellbay operator for 13 years. They are familiar with the nature of offshore work and managing their shift schedules and rest periods.[123]

[120] *See* NTSB_PHMSA_00000637 at NTSB_PHMSA_00000666.

[121] *See* Ex. 9, CSInc024124; Ex. 10, CSInc017004; Ex. 11, CSInc017005. With this response, Beta is providing additional records to demonstrate the training taken. As noted above, Controller 1 and Controller 2 have received extensive training on fatigue management. Thus, though they did not take CRM02 training in 2017 and 2018, they are experienced controllers, and they are aware of fatigue management strategies and how to recognize the signs of fatigue.

[122] *See, e.g.*, Ex. 12, AMPLIFY-00188725; Ex. 13, AMPLIFY-00188721.

[123] Regardless, whether the Controller Trainee or the Pipeline Superintendent should be included in an assessment of the fatigue training records of "controllers and control room supervisors who were present at the time of the Failure

Finally, even if there had been a lapse in fatigue training (and there was not), there is no basis to conclude that fatigue played a material role in the failure event. PHMSA offers no such evidence. Indeed, although the federal government alleged in its indictment that Beta operated the Pipeline with a fatigued crew, the plea agreement did not include any such discussion and the government did not substantiate those allegations.[124]

H. Item 8: Training (§ 195.446)

Beta contests Item 8, which identifies four alleged gaps in Beta's training of controllers. Before addressing each alleged gap below, Beta makes three preliminary points.

First, Beta employed experienced controllers. Controller 2 had worked on offshore platforms for 25 years and had been a control room operator on Platform Elly since 2013. Controller 1 had worked for Beta for 13 years and had been a control room operator since 2015. Controller 1 and Controller 2 were experienced control room operators who had received extensive, industry-standard knowledge- and skills-based training on how to operate the Pipeline safely, including with respect to leak detection, prevention, and response.

Second, Beta provided extensive training to its controllers to carry out their roles and responsibilities. Beta required its employees to complete a variety of knowledge- and skills-based training, including three-day T2 trainings, one-day T2 refreshers, OQ trainings, Job Performance Evaluations, online safety training, and emergency drills. Beta incorporates its summary of the trainings in Part I(F).

Third, like other pipeline companies, Beta supplemented its knowledge-based training with on-the-job training to teach controllers the skills needed to successfully operate and maintain the Beta systems. Skills-based training starts early. As part of the MOC process, an operator-in-training works simultaneously with more experienced operators before they are allowed to "solo" in the control room. On-the-job training is continuous. "Time in the chair" (*i.e.*, experience by doing) is critical, and both Controller 1 and Controller 2 had thousands of hours of relevant experience in the Elly control room. Every pipeline has its own unique design and mode of operation, and control room operators develop not only equipment-specific understanding but also effective methods for identifying and troubleshooting issues, like upsets. On-the-job training helps ensure that Beta employees develop and hone the skills necessary to operate and troubleshoot equipment, including the Pipeline.

Regarding PHMSA's specific contentions, Beta responds as follows:

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event," the Pipeline Superintendent took the CRM02 - Fatigue training on July 21, 2014, April 5, 2016, and April 9, 2019, and March 2, 2022, and the Controller Trainee took it on September 10, 2017 and December 5, 2021. *See* CSInc024124.

[124] As Beta informed PHMSA on June 10, 2022, Beta's OQ trainings are administered by Compliance Services, Inc., a third party. Beta provided PHMSA with a demo account to access the training platform. The demo account enabled PHMSA to view the course notes and the online tests that a trainee must complete prior to receiving credit for the module.

Responding to abnormal operating conditions. Beta's controllers were formally trained in responding to abnormal operating conditions:

Controller[125]	OQAOC	OQ29/45	OQ43A	OQ43B
Controller 1	05/19/2013 04/3/2018 02/21/2022	05/19/2013 04/03/2018 10/10/2021	06/17/2013 04/14/2018 08/26/2019	06/17/2013 04/14/2018 08/26/2019
Controller 2	03/18/2008 04/30/2011 04/9/2016 04/23/2019 03/19/2022	09/16/2008 08/18/2012 04/08/2016 08/02/2016 07/26/2019 06/17/2022	03/18/2008 10/24/2009 05/14/2013 08/12/2016 08/13/2019 08/11/2022	03/18/2008 10/24/2009 05/14/2013 08/12/2016 08/13/2019 08/11/2022

Further, on-the-job training, or skills-based training, is key for operators to respond to abnormal operating conditions, like upsets. Upsets can vary widely in cause, severity, and duration, and personnel respond to them according to the specific circumstances of the upset and based on their own professional experience and judgment.

Working knowledge of the pipeline system. Beta ensures its controllers have a working knowledge of the pipeline system. It begins with the MOC process, which includes plant and control room walkthroughs. Then, controllers participate in a multi-day, T2 training program, known as Production Safety Systems Training; it provides training on the use and maintenance of devices and safety systems and develops a working knowledge of process and instrumentation diagrams, safe charts, and the process for their updating and maintenance. (Controller 1 and Controller 2 were most recently T2-certified on October 18, 2020.[126]) Several OQ modules also help Beta controllers develop a working knowledge of the Pipeline system, including OQ43A and OQ43B. In addition, on-hitch employees provide "turnover" notes to their off-hitch counterparts, which provide an opportunity for employees to learn how their counterparts experienced and resolved issues. Employees will also sometimes circulate summaries of incidents that took place to improve each employee's understanding of how to respond to and/or prevent similar incidents from occurring again.[127] Finally, on-the-job training and time in the chair provides immeasurable experience working directly with the Pipeline system. Controller 1's and Controller 2's knowledge of the Pipeline system is demonstrated by their many years of safely operating the Pipeline.[128]

[125] *See, e.g.*, Ex. 14, CSInc017017; Ex. 15, CSInc016983; Ex. 16, CSInc017009; Ex. 9, CSInc024124. The Pipeline Superintendent is not a controller under the Control Room Management procedures. His compliance with Beta's AOC training requirements does not bear on whether Beta complied with 49 C.F.R. §195.446, which is limited to a "controller training program."

[126] Ex. 17 - AMPLIFY-00154767.

[127] Ex. 18 - AMPLIFY-01125519.

[128] Beta disputes PHMSA's contention that Beta did not provide records "to show that controllers were trained on Normal Operating Procedure contained in the Pipeline Specific O&M PSOM 17.00." PSOM 17.00 is not a specific procedure in the O&M; rather, Procedure 17.00 is the first page of the PSOM and refers employees to the operating procedures that are included in Section 17, 18, and 19 of the O&M. *See* NTSB_PHMSA_00000355. Beta's O&M does not have defined "normal operating procedures," but rather includes specific procedures related to the normal operation of the Pipeline, *i.e.*, when abnormal operating conditions are not present. Such normal operating procedures include: (1) Normal Start Up and Shutdown of the Pipeline (Procedure 17.05), and (2) Pigging (Procedure 17.06). As noted above, Beta trains its controllers on both topics (OQ43/OQ43B and OQ29/OQ45, respectively).

Beta provides controllers an opportunity to review relevant procedures. Beta's personnel MOC process requires controllers to review relevant procedures before they can be certified as controllers.[129] The procedures are also available in electronic form. In addition, the OQ training modules that Beta employees take include references to Beta-specific procedures.[130] Further, as part of the MOC process for procedural changes, controllers periodically review and comment on potential revisions.[131]

Providing control room team training and exercises including controllers and other individuals. Beta controllers participate in several training exercises in which controllers and other individuals "who would reasonably be expected to operationally collaborate with controllers during normal, abnormal or emergency situations." First, they do it every day, working together to troubleshoot issues, in real-life circumstances. Second, Beta controllers participate in Beta's monthly "Emergency Drills" (one for each crew during its respective 14-day hitch). These drills each cover a specific emergency scenario, including (1) fire and explosion; (2) man down, man overboard, and platform evacuation; (3) terrorism; (4) severe weather; (5) uncontrolled well blowout; (6) hydrogen sulfide and other chemical release; (7) earthquakes; and (8) other scenarios as may be applicable in offshore production operations. These drills are team training exercises in which controllers work on responding to abnormal and emergency situations.[132]

With this response, Beta is providing additional supporting documentation to show how Beta trained its controllers. On the existing record, however, there was no violation, in light of the explanations provided above. Nonetheless, even if PHMSA has additional questions about Beta's training program after reviewing this response, Item 8 should be reassessed in light of the additional supporting documentation provided herewith.

I. Item 9: Controller Qualifications (§ 195.505)

Beta contests Item 9, which alleges that Beta failed to sufficiently evaluate that "individuals performing covered tasks were qualified."

Beta thoroughly evaluates its personnel and their qualifications. As a first—and important—step, a MOC process is started when an existing or new hire fills a position. Depending on the position, the MOC process requires that a position-holder complete a written test, conduct an operational walk-through, review relevant procedures, participate in on-the-job training, and complete relevant training modules. The evaluation does not end when the employee assumes the new position. There is daily interaction between shore-side management and the offshore crew—both in-person visits to the platform, as well as regular calls (including the standing, daily 6 a.m. safety meeting). There are also annual performance reviews. Further, management receives and evaluates daily production reports, bi-weekly hitch turnover notes, and Job Performance

[129] Ex. 19, AMPLIFY-00138324.
[130] *See, e.g.*, Ex. 16, CSInc017009.
[131] Ex. 20, AMPLIFY-00678291.
[132] Regarding PHMSA's contention that controllers do not participate in spill drills, that misunderstands the purpose of spill drills. Spill drill scenarios, which are approved by state and federal regulators, are designed to test a pipeline operator's ability (and in particular, an operator's designated Spill Management Team) to respond to a spill once oil is confirmed in the water. They are not principally designed to test an operator's management of the Pipeline.

Evaluations. Further, as Beta explained in Part I(F), Beta provides its crew with extensive training that allows them to operate the Pipeline safely. Beta's robust training program also provides evaluation opportunities. The training program includes multi-day T2 training, monthly safety training courses (on topics like spills, troubleshooting, and emergency planning), OQ training, monthly "Emergency Drills," and spill-identification, spill-notification, and spill-response training. In short, Beta thoroughly evaluates the qualifications of its employees through multiple touch points.

To support its allegations in Item 9, PHMSA identified purported issues with the qualifications and trainings of three personnel, a Controller Trainee, Controller 1, and the Pipeline Superintendent. None have merit.

Controller Trainee. The Controller Trainee has worked at Beta since 2008. He is an experienced and highly valued team member, with deep knowledge about the Elly plant. As of 2021, the Controller Trainee was an Automated Controls Repairman and Instrumentation Technician. He was training to be a qualified controller. As part of that qualification process, the Controller Trainee would occasionally work in the control room, shadowing a qualified controller—consistent with 49 C.F.R. § 195.505(c). Beta's policies and procedures allow for and encourage this hands-on shadowing and development; it is a key element of Beta's operational training and reflects Beta's extensive on-the-job training program. The Controller Trainee also had extensive formal training. He had taken the following trainings, among others: Abnormal Operating Conditions; Chemical Hazards; Control Room Management; Fatigue; Hazard Communication; Incident Reporting; Internal Corrosion Monitoring; Maintain & Repair Relief Valves and Pressure Limiting Devices; Pig Launchers/Receivers; Pipeline Emergency Response; and PLC or Instrumentation Control Loops.[133]

On the night of September 30, 2021, the Controller Trainee stepped in as a relief controller because Controller 2 was unable to travel to Long Beach due to one of the catastrophic California wildfires that was burning near his home. The Controller Trainee's shift was limited to several, overnight hours. Controller 1 was in the control room with the Controller Trainee for a short time to finish the morning report. The Controller Trainee was also assisted by the nighttime outside operator. Although PHMSA does not allege that any safety or operational issues arose during the Controller Trainee's shift, if there had been any such issues, the Controller Trainee would have been able to call the Platform Superintendent, among others. Regardless, the Controller Trainee's shift ended by 6:00 a.m. on October 1, 2021, many hours before either the operational upset or leak alarms. The Notice is therefore overstated to the extent it seeks to penalize Beta for the Controller Trainee's assistance during the failure event, as he did not serve as a controller during it, and there is no evidence connecting anything from the Controller Trainee's shift to any of the issues alleged by PHMSA regarding October 1 and October 2.

Controller 1. Controller 1 was an experienced control room operator who had over a decade of experience as a control room operator, facility operator, and wellbay operator. When Controller 1 became a control room operator in 2015, he completed a number of walk-throughs and trainings, as detailed above. Since then, Controller 1 had thousands of hours in the chair.

[133] The Controller Trainee was not required to complete several trainings that PHMSA identified in the Notice, including OM01 and OM02 trainings. *See* Ex. 21, AMPLIFY-00987164.

Although Controller 1 did not complete formal Control Room Management training in 2017 or 2020, he took it in 2018 and 2019. He also took *Control Center Operations of a Pipeline, Including Startup/Shutdown* in 2013, 2018, and 2019. Further, although Controller 1 had not renewed his Abnormal Operating Condition training at the time of the spill, he had taken the course at least twice previously. He had also taken *Control Center Operations of a Pipeline, Including Startup/Shutdown* and *Field Operations of a Pipeline, Including Startup/Shutdown* (both of which train controllers on responding to abnormal operating conditions) in 2013, 2018, and 2019. Controller 1 also took *Pipeline Emergency Response (Gas/Liquid)* in 2019. Regardless, the Notice does not—and there would be no basis to—suggest that any of these modest training gaps by one crew member contributed to the leak event.

The Pipeline Superintendent. Although PHMSA contends that the Pipeline Superintendent did not take CRM01 training, he took it on July 21, 2014, April 4, 2016, and August 21, 2019 (and March 2, 2022).[134] Further, the Notice states that the Pipeline Superintendent "did not have the AOC training in 2021." In fact, his AOC training was due to be renewed on December 27, 2021, so he was in compliance during the failure event and was qualified under Beta's AOC training until the last three days of 2021.[135]

In short, Beta conducts industry-standard and appropriate trainings for all of its control room operators at the appropriate intervals. Beta does so through internal trainings as well as third-party authorized trainings such as T2 Training. Additionally, each employee on shift during October 1 and October 2 had substantial experience and on-the-job expertise built up by a combined decades of work at Beta. There was no regulatory violation, and Item 9 should be withdrawn.

J. Item 10: Incident Reporting (§ 195.54)

Beta disputes Item 10. There was no violation of any incident reporting obligations, including with respect to Form 7000-1. As Footnote 76 of the Notice acknowledges, Beta worked in good-faith and in a timely fashion with PHMSA to troubleshoot issues with the Form 7000-1 and the online portal used to submit the form. Specifically, after initiating discussions with PHMSA on October 31, 2021 about the form, Beta attempted to upload a completed Form 7000-1—using the operative version of PHMSA's form (Rev 3-2021)—to the PHMSA Portal on November 1, 2021, within 30 days of the failure event. Beta, however, was unable to do so because the portal did not accept the operative version of the form. Beta communicated these difficulties to PHMSA that same day, and PHMSA informed Beta that Beta needed to upload a legacy version of the form (Rev 10-2014). On November 6, 2021, Beta's counsel provided a completed form (Rev 10-2014) to PHMSA and informed PHMSA that Beta could not submit the form using the portal because the portal required answers to every question, even those where answers were unknown and subject to ongoing investigations. Beta thereafter worked in good faith with PHMSA for several weeks to resolve these issues. After several discussions with PHMSA, Beta provided

[134] *See* Ex. 9, CSInc024124.
[135] *Id.*

a completed Form 7000-1, which PHMSA accepted.[136] For those reasons, there was no violation of § 195.54. While Beta appreciates that PHMSA does not seek to assess a penalty for Item 10, the proposed Warning Item is unwarranted, unnecessary, and should be withdrawn.

III. The Proposed Civil Penalties are Unwarranted and Excessive.

The proposed civil penalty should be withdrawn entirely or reduced substantially for multiple reasons. ***First***, Beta contests all nine of the proposed violations for which PHMSA seeks to levy a penalty, and no penalty is appropriate unless PHMSA establishes that there was, in fact, a violation. ***Second***, the proposed penalties misapply the assessment criteria in 49 U.S.C. § 60122 and 49 C.F.R. § 190.225. ***Third***, the proposed penalties depart from PHMSA precedent.

A. No Penalty is Appropriate Where Beta Contests the Underlying Violation.

To impose a civil penalty, PHMSA must establish a knowing violation of 49 U.S. Code Chapter 51, or a "regulation, order, special permit, or approval issued under this chapter[.]" 49 U.S.C. § 5123(a)(1). A person acts knowingly when she "has actual knowledge of the facts giving rise to the violation," or when a "reasonable person acting in the circumstances and exercising reasonable care would have that knowledge." *Id.* § 5123(a)(1); *see also Nat'l Power Corp. v. FAA*, 864 F.3d 529, 532-33 (7th Cir. 2017) (affirming that § 5123(a)(1) requires "knowledge of the facts giving rise to" the violation).

As a threshold matter, no penalty is appropriate where no violation occurred. *See* 49 U.S.C. § 60122(a)(1) (limiting penalties to those circumstances where the Secretary of Transportation "decides, after written notice and an opportunity for a hearing," that a person violated a regulation); *see also id.* at § 60122(b)(1)(A) (noting that, in "determining the amount of a civil penalty," the Secretary "shall consider . . . the nature, circumstances, and gravity of the violation"). As detailed above, Beta contests all nine of the proposed violations for which PHMSA seeks to levy a penalty. Until PHMSA establishes any of the violations, none of the nine proposed penalties are proper.[137]

B. The Proposed Penalties Misapply the Assessment Criteria.

Even if Beta committed violations, the penalties should be substantially reduced because the penalties do not accurately reflect the mandatory statutory and regulatory assessment criteria in 49 C.F.R. § 190.225.

The Nature and Circumstances of the Violation Do Not Warrant the Proposed Civil Penalties. 49 C.F.R. § 190.225(a)(1). As explained in detail in Part II, Beta did not commit any violations. Therefore, the nature and circumstances of the alleged conduct do not warrant any penalties.

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[136] Not only did Beta work with PHMSA in good faith and on a timely basis regarding Form 7000-1, Beta and PHMSA were in regular dialogue during the relevant time period. Among other things, Beta facilitated operator interviews within days of the spill event.

[137] If PHMSA later meets its burden and establishes any of the specific violations, then only that penalty should be assessed, subject to the arguments below. For example, if PHMSA establishes that there was a violation in connection with Item 1 and Item 1 only, the maximum penalty would be $50,200 (setting aside, for the sake of argument, all of Beta's other objections to the penalties).

The Civil Penalties Are Disproportionate to the Degree of Beta's Culpability. 49 C.F.R. § 190.225(a)(2). First, Beta did not cause the spill; the *Danit* and *Beijing* caused the spill when they dragged their anchors in a no-anchor zone, damaged and displaced the Pipeline, and failed to report what they had done. Reflecting the vessels' culpability, the vessels agreed to pay Beta $96.5 million, tens of millions to insurers, and $45 million to the civil class plaintiffs in settlements. Second, on the night of October 1, 2021, the Beta crew worked diligently and in good faith to troubleshoot what the crew believed were false leak detection alarms; no one has alleged otherwise. Third, instead of pointing fingers, Beta immediately went to work as a member of Unified Command to aid the clean-up, and as of March 31, 2023, Beta spent approximately $92.8 million in clean-up efforts, including reimbursement for federal, state, and local clean-up efforts.

Beta Does Not Have a History of Prior Offenses. 49 C.F.R. § 190.225(a)(3). The October 2021 spill was the first such incident from the Pipeline, or any Amplify-run operation, and it is not representative of Beta / Amplify or its operations, which have no pattern or history of wrongdoing. Beta has not been found to have engaged in any similar wrongdoing by any federal or state agency, or court. Instead, Beta has a long history of safety, responsibility, and constructive relationships with its many regulators. Prior to October 2021, the Pipeline had never leaked in its 40-year-plus history. PHMSA had not initiated any Enforcement Actions against Beta for more than a decade (and none during the period of Amplify's ownership). From 2006 to March 2023, Beta received just two warning letters (one in 2008 related to the inspection of main line valves and the pressure setting on two thermal relief valves, and one in 2010 regarding the entry of drug and alcohol testing results into the Management Information System).[138] Further, despite 157 inspections across Beta's five California assets since 2017, there were zero facility shut-ins before the spill. Of the 31 INCs since May 2017, 20 were resolved the same day and the others were addressed promptly. Beta also has a solid record of minimizing and preventing spills. There were no discharges of over a gallon of oil from any equipment in the Beta oilfield between 2015 and the October 2021 incident.

Beta Acted in Good Faith During and After the Spill. 49 C.F.R. § 190.225(a)(4). On the night of October 1, 2021, the Beta crew worked diligently and in good faith to troubleshoot what the crew believed were false leak detection alarms. Once oil was confirmed in the water, Beta promptly notified appropriate personnel and shut-in all remaining facilities. Beta then spearheaded the response and successful clean-up effort, played an important role in Unified Command, and funded the clean-up. Further, Beta cooperated fully with all investigations. And illustrating its commitment to safety and responsibility, Beta has used the spill as an opportunity to enhance its policies, procedures, and equipment.

Beta Did Not Gain Any Economic Benefit From the Violation. 49 C.F.R. § 190.225(b)(1). Beta did not gain any economic benefit from its actions before, during, or after the failure event. The vessel-caused spill has been a major disruption to Beta's business and drag on its finances. Beta has not been made whole by insurance reimbursements or the settlement with the vessels.

Justice Requires Reducing the Proposed Civil Penalty. 49 C.F.R. § 190.225(b)(2). Justice requires reducing the proposed civil penalty for any one of at least four reasons. First, Beta has a

[138] In 2008, Beta received two notices to amend certain procedures, which it did.

long and consistent record of safety and responsibility. Second, third parties damaged the Pipeline and caused the spill. Third, once oil was confirmed in the water, Beta immediately went to work to lead the clean-up and pay for it. Fourth, although any environmental damage is unacceptable, the degree of environmental damage here is much lower compared to the damage caused by other operators who have been assessed similar civil penalties, as explained in the next sub-section. In sum, justice requires reducing the proposed civil penalty given Beta's actions and given the penalties PHMSA has proposed to other pipeline operators.

C. The Proposed Penalties Depart from PHMSA Precedent.

The proposed penalties should be withdrawn or reduced because the penalties depart from PHMSA precedent at least two ways.

First, the penalties that PHMSA proposes would be the third largest that PHMSA has ever levied, according to data available on PHMSA's web site. Compared to three recent exemplar cases, PHMSA's proposed penalties are disproportionate to the facts and circumstances, particularly here where third-party misconduct is the cause of the oil leak:

Operator	Event and Proposed Penalties	Comparison
Kinder Morgan, Inc. 5-2021-022 May 12, 2021	Following a rupture in a pipeline operated by Kinder Morgan subsidiary Santa Fe Pacific Pipeline Partners, about 11,000 barrels of gasoline were released into Mesilla Valley near the Rio Grande River in New Mexico. PHMSA found that the cause of leak was external corrosion on the pipeline and that the control room operator did not immediately recognize the situation as a leak. PHMSA proposed a penalty of $2,231,779.	Although almost 22 times more liquid spilled than in the San Pedro Bay Pipeline incident (588 barrels), PHMSA is proposing a fine for Beta that is $1,157,955 greater. In other words, PHMSA proposed a fine equal to $202 per barrel of spilled gasoline for Kinder Morgan, but $5,764 per barrel of spilled oil for Beta. Further, at the time PHMSA issued the NOPV to Kinder Morgan, it had earned almost $200,000 in prior civil penalties related to the same pipeline. These included penalties for failure to inspect and test for pipeline corrosion—the exact cause of the 2021 Santa Fe failure. In contrast, before the April 2023 letters, Beta had received just two warning letters since 2006 (and none since 2010, and none during the period of Amplify's ownership). Further, those two warning letters were unrelated to the October 1, 2021 event.

Operator	Event and Proposed Penalties	Comparison
ExxonMobil Pipeline Company 5-2013-5007 March 25, 2013	The failure of Exxon's Silvertip Pipeline, which involved a pressure alarm that was not recognized by Exxon's controller, resulted in the release of over 2,500 barrels of oil into the Yellowstone River near Laurel, Montana. PHMSA proposed a penalty of $1,700,000.	Although the Exxon failure was four times larger than the San Pedro Bay Pipeline incident, PHMSA proposed a penalty 50% smaller than the penalty proposed to Beta. PHMSA proposed a fine equal to $680 per barrel of oil spilled for Exxon, but $5,764 per barrel of spilled oil for Beta. The NOPV that PHMSA issued to Exxon was Exxon's third in three years.
Enbridge Energy, LP 3-2012-5013 July 5, 2012	Enbridge's pipeline failed, resulting in the release of more than 20,000 barrels of crude oil and the contamination of 38 miles of the Kalamazoo River. PHMSA alleged 24 violations. PHMSA proposed a penalty of $3,699,200.	PHMSA proposed approximately the same penalty to Enbridge as it has to Beta, even though Enbridge received three times the number of violations and spilled approximately 35 times more oil. PHMSA proposed a fine equal to $185 per barrel of oil spilled for Enbridge, but $5,764 per barrel of spilled oil for Beta. At the time PHMSA issued the NOPV to Enbridge, Enbridge had five previous instances where PHMSA issued civil penalties. One of these penalties was $2,405,000 for a pipeline release that occurred just four years earlier that resulted in two fatalities. Another incident occurred just a year before that for a pipeline failure where over 3,000 barrels of crude oil were released. All told, Enbridge had incurred over $2.5 million in civil penalties prior to the 2012 NOPV.

Second, PHMSA has proposed civil penalties for alleged conduct that in the past warranted a compliance order, or no penalty at all. For example, in the NOPV to Kinder Morgan noted above, where 11,000 barrels of gasoline spilled, PHMSA alleged that, because Kinder Morgan did not provide the necessary "information, tools, processes and procedures," its controller "had inadequate information to recognize [the] event as a pipeline failure."[139] PHMSA alleged that this conduct violated § 195.446(c) and issued a compliance order, but none of the proposed civil penalties were tied to § 195.446 violations.[140] Although Kinder Morgan received no penalty for § 195.446 violations, PHMSA proposes a fine of $1,461,400 for Beta for alleged violations of the same regulation. Next, in a 2022 NOPV to Denbury Gulf Coast Pipeline, PHMSA alleged that Denbury violated § 195.52 by failing to timely notify the NRC after discovering a pipeline leak that resulted in the release of approximately 9,532 barrels of CO_2.[141] Specifically, PHMSA alleged that Denbury claimed that it verified the leak 22 minutes before Denbury contacted the NRC, when in fact Denbury had actual confirmation of the rupture at least an hour earlier than Denbury represented.[142] For this conduct, PHMSA did not propose any civil penalty for Denbury.[143] Although no one has alleged that Beta misrepresented anything, and Beta promptly made the required notifications as soon as oil was confirmed in the water, PHMSA has proposed a penalty of $50,200.

* * * * *

Because no violations occurred, PHMSA misapplied the assessment criteria, and the proposed penalties depart from precedent, the proposed civil penalties should be withdrawn entirely or reduced substantially. Ahead of the informal conference, Beta requests that PHMSA provide its original and/or amended penalty worksheet, so that Beta can more fully assess PHMSA's analysis and calculations and engage further about them.

IV. BETA AGREES TO THE PROPOSED COMPLIANCE CONDITIONS.

PHMSA proposed nine compliance conditions, exclusive of sub-parts. Beta agrees to all of them, subject to the clarifications and qualifications below, including that Beta has already implemented some of them. Beta agrees to these conditions to enhance safety and operations, and not as an admission of any prior shortcoming or to address any alleged regulatory violation.

A. Condition A

PHMSA Proposal: Condition A asks Beta to "Amend procedure SPBPL-001.00 - SPBPL 16 Manual Leak Detection to (a) Clearly define and provide an example(s) of what a 'communication breakdown' is; and (b) Clearly define when to use the procedure. For example, can this procedure be used when the LDS is working? Should this procedure not to be used to verify an LDS leak alarm? etc." PHMSA asks Beta to "[s]ubmit the revised procedure to PHMSA for review and approval within 90 days of the receipt of the Final Order."

Beta's Response: As noted above, Beta used the spill as an opportunity to invest in a comprehensive, top-to-bottom review of Beta's policies and procedures. Beta retained a third-party consultant, Eagle, to chair that effort. As part of Eagle's process, the Abnormal Operating

139 *See* Kinder Morgan NOPV (CPF 5-2021-022-NOPV) at 7.
140 *See id.* at 12.
141 *See* Denbury NOPV (CPF 4-2022-017-NOPV) at 3.
142 *See id.*
143 *See id.* at 13.

Conditions procedure have been revised and it now sets forth what must be done in response to a potential leak alarm. Beta will no longer do manual leak detection; "SPBPL-001.00 - SPBPL 16 Manual Leak Detection" is no longer in use. Beta will submit the entirety of the revised procedures to PHMSA and work with PHMSA to address any further revisions to the procedures.

B. Condition B

PHMSA Proposal: Condition B asks Beta to "Amend Procedure 17.05 Pipeline – Start Up and Shut Down of 16" SPBPL to include at a minimum: (a) A detailed description of activities to which the procedure applies (i.e., equipment maintenance, pigging operations, normal shipping, etc.); and (b) On page 5 of the procedure, under Abnormal Operating Conditions (AOC), clearly define the definition of 'immediately shut down the pipeline' and when immediate shutdown should be employed (e.g., whenever an AOC is detected, or LDS issues a leak alarm, both scenarios, etc.)."

Condition B further asks Beta to "Amend SPBPL 16" SPBPL-009.11 - Emergency Shutdown, Isolation and Drawdown Procedure to include at a minimum: (a) A process on how to determine the location of a leak accurately, with detailed step-by-step instructions for a controller to follow; (b) A process on when and how a drawdown procedure can be used; (c) A process on when and how to safely return the pipeline to service after an emergency shutdown; and (d) The title of the person who will be responsible for each specific task . . . ."

Condition B further asks Beta to "Amend Procedure 17.08 – Abnormal Operation to include at a minimum: (a) A form to document the investigation, corrective repairs, and replacement done for the abnormal operating conditions; (b) How often the review of personnel response to abnormal operating conditions to determine the effectiveness of the procedures controlling abnormal operation and taking corrective action where deficiencies are found will be done and a form to document the review; (c) Clearly define 'shutting down the system.'"

Condition B further asks Beta to submit (i) "the amended procedures to PHMSA for review and approval within 90 days of the receipt of the Final Order," and (ii) "the qualifications and training records of all controllers to demonstrate that they were trained pursuant to Section 6.5 of API Recommended Practice 1130[.]"

Beta's Response: As part of the comprehensive, Eagle-led review of Beta's procedures, all three procedures identified by PHMSA have been revised. Beta will submit the revised procedures to PHMSA. If the existing revisions do not sufficiently address PHMSA's specific requests, Beta will work with PHMSA to assess further revisions. Beta will also provide PHMSA with the qualification and training records of the control room operators.

C. Condition C

PHMSA Proposal: Condition C asks Beta to "amend its CRM Procedure to include a detailed process on how a deficiency will be promptly remediated."

Beta's Response: Beta is working with EverLine, a consultant, to amend its CRM procedures. These amendments will detail how a deficiency in control room management will be promptly remediated. Beta will submit the amended CRM procedures for PHMSA's review and approval.

D. <u>Condition D</u>

PHMSA Proposal: Condition D asks Beta to "amend its CRM Procedure to include a detailed process for: (1) Identifying and measuring the workload (content and volume of general activity) being directed to an individual controller, and (2) Means of determining that the controller has sufficient time to analyze and react to incoming alarms."

Beta's Response: As noted, Beta is working with EverLine to amend its CRM procedures. These amendments will detail how to identify and measure controller workload and identify a means to determine that a controller has sufficient time to analyze and react to incoming alarms. Beta will submit the amended CRM procedures for PHMSA's review and approval.

E. <u>Condition E</u>

PHMSA Proposal: Condition E asks Beta to "amend and submit to PHMSA for review and approval its procedure that includes a detailed process for defining who has authority and their qualifications to direct or supersede the specific technical actions of a controller and disallowing others to direct controller actions (in any operating mode), including the circumstance(s) in which he or she may do so, and how this practice will be documented."

Beta's Response: As noted, Beta is working with EverLine to amend its CRM procedures. These amendments will detail a process for defining who has authority—and their qualifications—to direct or supersede the specific technical actions of a controller, as well as a process for documenting that practice. The amendments will expressly disallow others from directing controller actions in any operating mode. Beta will submit the amended CRM procedures for PHMSA's review and approval. (The chain of command for restarting the Pipeline after a leak alarm is now addressed in the revised Abnormal Operating Condition procedure, which Beta will also submit to PHMSA for review.)

F. <u>Condition F</u>

PHMSA Proposal: Condition F asks Beta to provide (1) "training on fatigue risk management to all controllers and supervisors," and (2) "PHMSA a copy of Fatigue Risk Management training materials that will be used to train all controllers and supervisors."

Beta's Response: Beta will conduct a supplemental fatigue risk management training for controllers and their supervisors, and Beta will provide a copy of those supplemental training materials to PHMSA.

G. <u>Condition G</u>

PHMSA Proposal: Condition G asks Beta to "amend its CRM Procedure to include: (1) The name or title of the training modules that the controllers are required to take and how often they have to take the trainings; (2) A detailed process for providing an opportunity for controllers to review relevant procedures in advance of their application for setups that are periodically, but infrequently used; (3) Establishing who, regardless of location, operationally collaborates with control room personnel; (4) Defining the frequency of new and recurring team training; (5) Addressing all operational modes and operational collaboration/control; and (6) Incorporation of lessons learned from actual historical events and other oil-gas industry events."

Beta's Response: As noted, Beta is working with EverLine to amend its CRM procedures. These amendments will include all six of the requested additions. Beta will submit the amended CRM procedures for PHMSA's review and approval.

H. Condition H

PHMSA Proposal: Condition H asks Beta to agree that "Upon approval of all the amended procedures by PHMSA," Beta will (1) "Review the approved amended procedures with and provide a training simulation to all facilities operators, control room operators, persons-in-charge (PICs), supervisors, superintendents, and safety personnel within 90 days of PHMSA's approval; and (2) Provide records to PHMSA to demonstrate that review and training has been conducted and submit all the completion records to PHMSA within 30 days of the review and training completion."

Beta's Response: Beta will comply with this condition.

I. Condition I

PHMSA Proposal: Condition I asks Beta to "maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Mr. Dustin Hubbard . . . . It is requested that these costs be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies, and analyses, and 2) total cost associated with replacements, additions, and other changes to pipeline infrastructure."

Beta's Response: Beta will comply with this condition.

V. CONCLUSION

Beta appreciates PHMSA's engagement and the opportunity to work productively with PHMSA to address its findings. We look forward to discussing further at your convenience.