INVESTIGATION INTO THE CAUSES OF THE FIRE OF FEBRUARY 23, 1999 AT NO. 50 CRUDE UNIT TOSCO AVON REFINERY

PRELIMINARY REPORT TO THE CONTRA COSTA COUNTY BOARD OF SUPERVISORS

Contra Costa Health Services

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EXECUTIVE SUMMARY

On February 23, 1999, a fire at the No. 50 Crude Unit at the Tosco Avon Refinery resulted in the deaths of four workers and permanent injuries to a fifth worker. Contra Costa Health Services and CalOSHA initiated a their investigations on February 23rd, and the U.S. Chemical Safety and Hazard Investigation Board initiated their investigation on February 26th.

The incident occurred while naphtha piping was being dismantled for replacement. The crude unit was operating at the time. The immediate cause of the fire was that naphtha was released from the piping being dismantled and contacted surfaces of the operating equipment that were hotter than the auto-ignition temperature of the naphtha and the naphtha ignited.

The naphtha piping being replaced had been taken out of service on February 10, 1999, due to a leak. The CCHS investigation focused on events starting on February 10th after the leak was isolated to determine how the naphtha was physically released, and the contributing and root causes that led to the situation that the naphtha could be released causing the subsequent fire.

PHYSICAL RELEASE

The naphtha piping runs from Fractionator to the Naphtha Stripper as shown in Exhibit 2 (all exhibits are in Appendix A). After Valve A was closed to stop the leak, the piping remained about 70% full. The line remained 70% full due to the “U” shaped liquid trap formed by the bottom of the piping, and the fact that the pressure in the operating Naphtha Stripper supported (pushed up) a vertical leg of naphtha in the piping next to the Fractionator. The naphtha was physically released from the piping as follows: Following unsuccessful attempts to drain the line before starting to dismantle it, Tosco workers cold cut and removed the top section of the piping above the liquid level (Exhibit 5). Tosco workers then initiated a second cold cut below the liquid level that leaked naphtha. Tosco workers then began draining the line from a flange as shown in Exhibit 6. Valve B leaked badly, though this was not known on February 23rd. Consequently, as naphtha was being drained, the level of the vertical leg of naphtha next to the Naphtha Stripper dropped. This vertical leg was a liquid seal that prevented naphtha vapors from the Naphtha Stripper flowing through Valve B. When sufficient naphtha was drained, the liquid seal was broken, naphtha vapors flowed through Valve B mixing with and lifting naphtha liquid up and out of the piping next to the Fractionator (Exhibit 8). The naphtha ignited off hot Fractionator surfaces.

CAUSES OF THE RELEASE AND FIRE

A causal analysis was done to determine both contributing causes and root causes.

Several contributing causes were found, two which were serious and significant. These two were (1) on February 23rd, the piping was not properly prepared according to Tosco written safety procedures: workers did not, but should have drained, depressured, cleaned and positively isolated the piping before work started, and (2) on February 23rd, workers and a supervisor did not exercise stop-work authority while unsafe work was in progress.

The situation should not have evolved such that the workers were put in the position to have to make the decisions leading to the contributing causes.

Between February 10th and February 23rd there were events that were warning signs that valves were leaking, that the line was essentially full of naphtha and that the drain valves were plugged so the operators could not drain the system. Managers and first line operating supervisors did not know this information.

The job involved dismantling a line containing naphtha located directly above sources of ignition. No plans for safely preparing the line were made for the operators to supplement the standard safety procedures. No one in operations supervision took charge of the safe execution of the job to ensure that standard safety procedures were being implemented, or that appropriate supplemental procedures were prepared and implemented.

CCHS therefore found that the root causes of the incident were less than adequate management systems in the areas of (1) poor communications between the operators and their supervisors that resulted in the managers and supervisors not being aware of the warning signs, and (2) the responsibility of managers and supervisors to recognize situations that they should proactively become involved in and provide leadership to the workers to ensure that the work is safely done. CCHS recommendations are for Tosco to address and correct these management system deficiencies.

SECTION 1.

PURPOSE OF THE INVESTIGATION

The purpose of any incident investigation is to understand the causes of the incident in order to improve the ability to predict the likelihood of future occurrences and to be able to recommend and implement actions to reduce the likelihood of future occurrences. These causes are frequently the result of organizational factors that result in human errors being made at various levels in the organization. In describing and analyzing the causes of the fire of February 23rd, we will discuss human errors that were made at various levels in the Tosco organization that were involved in either contributing causes or root causes of the incident.

SECTION 2

SCOPE OF THE INVESTIGATION

The scope of this Contra Costa Health Services (CCHS) root cause analysis includes the activities contributing to the February 23, 1999 fire at the No. 50 Crude Unit (50 Unit) at the Tosco Avon Martinez Refinery that resulted in the deaths of four workers and critical injuries to a fifth worker. The fire resulted from a release and ignition of naphtha during replacement of out of service naphtha piping. The naphtha piping was taken out of service on February 10, 1999 due to a leak in the line. The scope of our root cause analysis for the fire starts with the events on February 10th that began with the closing of the first valve to isolate the naphtha piping and ends with the ignition of the fire on February 23rd. CCHS considers the initial leak that resulted in the naphtha piping being taken out of service a separate incident that ended with isolation of the leak. Therefore, causes of the leak itself are not part of the root cause analysis. The leak was caused by corrosion. Appendix B discusses possible causes of this corrosion and current Tosco efforts aimed at minimizing future corrosion. Similarly, CCHS considers Tosco's emergency response to the fire to be outside the scope of the root cause analysis.

SECTION 3

PROCESS DESCRIPTION

The 50 Crude Unit is the first step in the refining process of crude oil at the Tosco Avon Refinery. Currently, 50 Unit is the only crude unit at Tosco Avon. It has the capacity to process approximately 100,000 barrels of crude oil per day.

GENERAL DESCRIPTION

Crude oil is a mixture of various hydrocarbons, such as pentanes, hexanes, and aromatic compounds. A refinery crude unit, or fractionation unit, separates the mixture of hydrocarbons into various components, or fractions, for use throughout the rest of the refinery. This separation is achieved by heating the crude oil, feeding the oil into a tall column (usually called a Fractionation Tower or Fractionator), and removing the various components from the Fractionator at different heights, based on the boiling points of each of these components.

The "lighter" components (those with low boiling points, e.g., naphtha, gasoline, butanes, etc.) are typically removed from the upper portions of the Fractionator, while the "heavier" components (higher boiling point liquids, e.g., gas oils, resid, etc.) are remove from the lower portions of the Fractionator. There are also mid-boiling point range materials removed from the middle portions of the Fractionator (e.g., kerosene, diesel, etc.).

A crude unit can process different types of crude oil, depending on the origin of the crude. Certain oil fields contain higher quantities of lighter components than others. As crude is heated and fed to the crude Fractionator, changes in tower pressure result, due to the increase in temperatures and the boiling of the hydrocarbons. The amounts of the various products leaving the Fractionator will change. These "swings" in the unit operation are recorded by process sensors (measuring temperatures, pressures, and flow rates), and monitored by operators who make process changes to the crude unit to ensure safe and efficient operation of the unit.

Crude oil also contains varying quantities of contaminants such as sulfur-containing compounds, organic and inorganic salts, organic and inorganic acids, solids, and water. Optimally, most of these contaminants are removed prior to feeding the crude to the Fractionator. There are, however, downstream units that also remove contaminants from crude unit products.

50 UNIT PROCESS

50 Unit is composed of three systems: feed treatment, fractionation, and stabilization. There are numerous “steps” performed within each of these systems. A simplified diagram of 50 Unit is provided in Figure 3-1.

The feed treatment system

The heat from the fractionated products is transferred to the incoming crude oil in crude preheat exchangers. The products leaving the Fractionator at temperatures higher than the entering crude oil exchange their heat with the crude oil. This is done to conserve thermal energy in the crude oil in order to minimize the fuel consumption in the Furnace.

One of the processes the crude oil undergoes before entering the crude tower is desalting. Desalting is necessary to remove salts and other potential contaminants from the crude oil that may cause corrosion in downstream process piping and equipment. This is accomplished by mixing the raw crude oil with wash water, and feeding this mixture into large horizontal vessels called Desalters. The water (now containing significant amounts of the contaminants) separates from the oil and is removed. The desalted crude then can proceed through the remainder of the preheating and fractionating processes. More information on contaminants in crude oil and methods to control them is included in Appendix B, Corrosion Control and Laboratory Results.

After the Desalters, the crude oil is again preheated and fed to the Flash Column. In the Flash Column, light components from the crude (i.e., naphtha, gasoline, butanes, etc.), heated to above their boiling points during crude preheating, “flash” off or, or are instantly vaporized from, the crude and are fed to the Fractionator via the Flash Column overhead line.

The heavier components of the crude, still in liquid form, leave the Flash Column and are pumped through the Furnace. The Furnace is a “fired” heater that uses fuel gas to heat the crude oil as it flow through pipes in the Furnace firebox. The crude oil is heated to approximately 700°F and fed to the Fractionator.

The fractionation system

The Fractionator separates the components of the crude oil into various product streams, the lightest components moving up the tower, and the heavier components moving down the tower. The product streams, in order from lightest to heaviest, are wet gas, gasoline, naphtha, kerosene, diesel, atmospheric gas oil (AGO), and resid. Stripping steam is injected into the bottom of the Fractionator to assist in the separation process.

The wet gas (methane, ethane, and noncondensable gases), butanes, and gasoline vapors leave the Fractionator via the overhead line. All but the wet gas is condensed in the Overhead Condensers and the liquid collects in the Accumulator. Some of the liquid is pumped back to the Fractionator as “reflux”, which aids in the Fractionator separation process. The rest of the liquid is sent to the Debutanizer for the stabilization process.

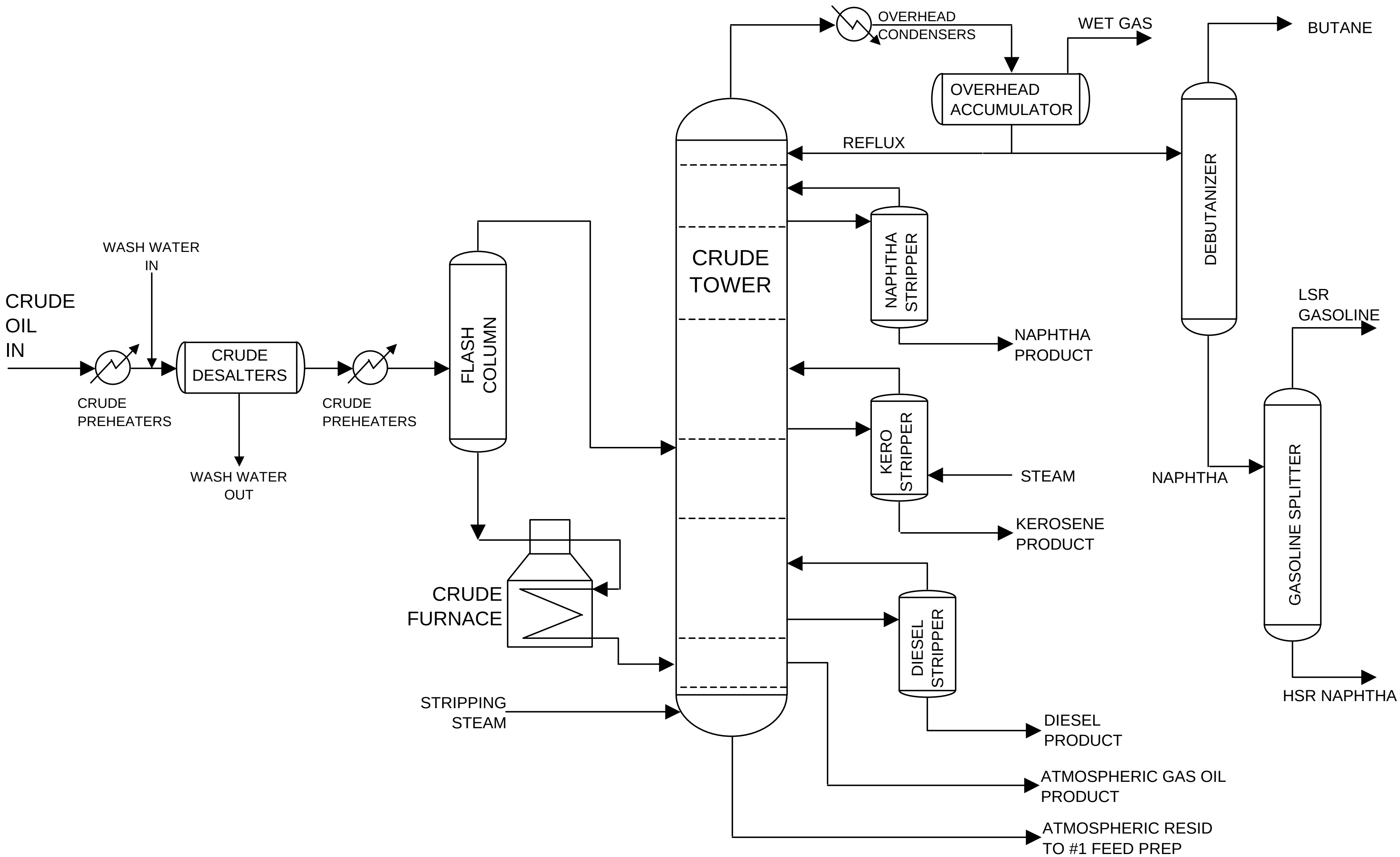
Naphtha, kerosene, and diesel products are each drawn from separate trays in the Fractionator and sent to dedicated stripper towers. In each stripper tower, the lighter vapor components from each product (e.g., kerosene from vapor in the diesel stream, etc.) separate and flow back to the Fractionator. The liquid from each stripper tower is pumped to dedicated product tankage for further processing at downstream units. Only the Kerosene Stripper has stripping steam injected for additional light end removal.

The AGO and resid product streams are each cooled and sent to storage.

Stabilization

The overhead gasoline product is sent to the Debutanizer for stabilization (i.e., removal of light ends such as butanes and lighter components). These butanes and lighter components leave the Debutanizer through the overhead line. The Debutanizer bottoms (also called naphtha) is fed to the Gasoline Splitter, where light straight run (LSR) gasoline (i.e., near product-grade gasoline) is removed in the overhead, and heavy straight run (HSR) naphtha flows through the bottoms line. HSR naphtha is combined with the product naphtha from the Naphtha Stripper bottoms at the Fractionator prior to going to tankage and further treating to produce gasoline.

FIGURE 3-1
50 UNIT SIMPLIFIED FLOW DIAGRAM



SECTION 4

EVENTS BEFORE FEBRUARY 23, 1999

Note: All Exhibits referred to are in Appendix A. Valves names, e.g., Valve A, are the names assigned in the exhibits.

ORGANIZATIONS INVOLVED

Three organizations at Tosco were involved in the events surrounding the fire of February 23rd. These are shown on Chart 4-1. These organizations are the:

- Production Day Organization
- Operations Shift Organization
- Maintenance Execution Organization (Elements thereof)

This report makes reference to managers and supervisors. Supervisors means the first line supervisors who are the Operations Supervisor, Shift Supervisors, and the Maintenance Supervisor. Others above these first line supervisors are included in the meaning of management. When we refer to workers, we mean operators, maintenance mechanics, and contractors. It should be noted that the titles No. 1 Operator and Shift Supervisor do not necessarily refer to the same individual. There is one of each position on each of four shift crews.

LEAK ON FEBRUARY 10TH

On February 10, 1999, a leak was discovered in the naphtha draw line that runs between Fractionator V-1 and the Naphtha Stripper V-3. The leak was immediately downstream of the Fractionator naphtha block Valve A on the bottom of the line as indicated in Exhibit 1-A. Tosco decided to stop the leak and isolate the naphtha piping while keeping the Fractionator in operation. Tosco operators reduced the Fractionator operating pressure from about 12.5 psig to about 10.2 psig and made other operational changes that minimized the leak. Two Tosco supervisors then climbed up the Fractionator ladders and closed Valve A. This act of closing

Valve A ended the February 10th leak incident and is the starting point of the CCHS scope of investigation into the causes of the fire on February 23, 1999. After Valve A was closed, only about 30% of the naphtha in the piping between the Fractionator and the Naphtha Stripper could drain into the Naphtha Stripper. Drainage was limited to 30% because of the configuration of the piping and because the Naphtha Stripper was still at operating pressure. The piping configuration is such that the piping from the Fractionator goes to a low point before rising into the Naphtha Stripper. This configuration forms a "U" shaped liquid trap (like a kitchen sink trap) that contained naphtha to the level of the Naphtha Stripper inlet. In addition, the pressure in the Naphtha Stripper supported (pushed up) a vertical column of naphtha 30 to 31 ft. above the liquid trap level. This situation is shown in Exhibit 2. After Valve A was closed, operators closed Valves B, C, and E.

INSPECTION OF PIPING

Tosco promptly initiated a thorough inspection of the entire naphtha system on the evening of February 10th that took several days. Both X-ray and ultrasonic thickness testing methods were used to determine pipe thickness. The bottom of the piping at the leak location was determined to be thin and the leak itself was later found to be due to corrosion. (Refer to Appendix B for a discussion of the possible causes of this corrosion.) Other areas in the piping showed significant loss of thickness. Tosco inspectors initially recommended replacing all the piping between the Fractionator and the Naphtha Stripper. However, the piping between Valves B and E and the Naphtha Stripper cannot be replaced while the Fractionator is operating because the Naphtha Stripper was at operating pressure and there is no valve at the Naphtha Stripper end of the piping from the Fractionator for isolation. In addition, this piping that cannot be replaced with the Fractionator operating had acceptable thickness. Consequently, Tosco operating supervisors and inspectors made a decision to immediately replace the piping between Valve A and Valves B and E with the Fractionator operating, and to replace the piping between Valves B and E and the Naphtha Stripper during the next scheduled maintenance turnaround. In the meantime, the piping between Valves B and E and the Naphtha Stripper would be subject to frequent thickness testing to verify continuing safe operation.

Note: Before restarting 50 Unit after the refinery standdown, Tosco replaced all piping and valves in the naphtha system between the Fractionator and the Naphtha Stripper.

OPERATIONAL AND MAINTENANCE EVENTS BETWEEN FEBRUARY 10, 1999 AND FEBRUARY 23, 1999

Determination of Liquid Level

Exhibits 1A, 1B, and 1C show the naphtha levels assumed by various people at Tosco after the valves were closed on February 10th. Some at Tosco assumed a low naphtha level in the piping as shown in Exhibit 1A. Some assumed the "sink trap" level of Exhibit 1B and others thought the level was high as depicted in Exhibit 1C. However, the actual level was never determined before the fire. The Maintenance Supervisor was observed hammering on the line during the week of February 15th trying to determine the liquid level in the line. Exhibit 2 shows the actual naphtha level that had to be in the line after Valve A was closed after the leak of February 10th.

Leak on February 13th

The line leaked again on February 13th at the point of the original leak. The operators further tightened down on both Valve A and bypass Valve B. The operator wrote in the operator log book "the ruptured draw line is full", but did not mention the leak in the log. A Shift Supervisor assisted in stopping the leak, but apparently did not pass this information along. Other supervisors and managers indicated they did not receive this information.

Naphtha Stripper Pumpout

Chemical Safety Board investigators determined by review of the 50 Unit operating records and discussions with an operator, that the operators pumped out the Naphtha Stripper once on February 13th, and pumped it out five times on February 14th. Valves A and B were further tightened by the operators on February 14th and a valve on the bottom outlet piping system was left open and the high level did not return. This pumping out was not noted in the operator's log. A Shift Supervisor stated in his written turnover log of February 14th, "pumped out level in Naphtha Stripper" referring to the single pumpout of February 13th. The Shift Supervisor turnover logs are available electronically to all supervisors and managers.

Leak on February 17th

The line leaked again on February 17th at the point of the original leak. The operators further tightened down on both Valve A and bypass Valve B. Again, no mention of this leak was made in the operator's logbook.

Plugged Drain Valves

Also on February 17th, the No. 1 Operator told the Business Team Leader that drain Valves F and G were plugged (see Exhibit 2). The Business Team Leader relayed this information to the Operations Supervisor. That same day, the No. 1 Operator also discussed the plugged drain valves and inability to drain via these valves with the Operations Supervisor and the Maintenance Supervisor. As a result the Operations Supervisor made arrangements for maintenance mechanics to drill (clean) out the drain valves the next day.

The operators entered into their log for February 17th, "Beat about ½ spoke out of the naphtha draw valve (Valve A) and the C/V bypass valve (Valve B), (which means that the operators hammered the valves further closed one-half the distance between spokes of a handwheel). Both bleeders are plugged and cannot ease up (unplug) with a welding rod-will need to drill out eventually."

On the afternoon of Thursday, February 18th, maintenance mechanics attempted to drill out the drain valves but were unsuccessful. The drills used are attached to flexible cables. The cable attached to the drill was broken in the attempt. The operators entered into their log: "fitters made attempt to bore out naphtha stripper LCV (level control valve) bleeder valves, but no go." Again, this information was not transmitted to supervisors and managers.

Discovery of Sludge

On Friday, February 19th, maintenance mechanics signed in to 50 Unit at noon time to, according to their sign-in sheet entry: "Drain 6" line on Fractionator Tower and unplug 1" drain valve." Before the maintenance mechanics arrived, the operators had filled out a work permit for the maintenance mechanics to remove the short section of pipe between the level Control Valve D and the downstream block Valve E (see Exhibit 4). The maintenance mechanics removed the section of pipe and found it contained a small amount of black sludge. There was also a small amount of sludge in the downstream block Valve E. However, the outlet of Control Valve D was full of sludge. The maintenance mechanics then installed a blind flange on Valve E and a blind flange with a drain valve on the Control Valve D. The operators and Maintenance Supervisor were aware of the sludge at this time. Managers or operating supervisors indicated that they did not receive this information. No attempts were made to drain from the newly installed drain valve on the control valve on February 19th. Apparently, it was planned to attempt draining again on Monday, February 22nd because the operators made the following log entry: "Fitters (maintenance mechanics) swung spool piece (section of pipe) just downstream of naphtha LCV and will drain leg up to frac (Fractionator) tower on Monday."

Four Bolting and Deck Hole Enlargement

On Monday, February 22nd, maintenance mechanics "four bolted" (removed four of the eight bolts from) each flange in the naphtha piping from Valves B and D to Valve A to facilitate removing the piping the following day. No attempts were made to drain the line that day. Preparations were also made to facilitate removal of the top section of piping. This involved enlarging the hole in a steel deck that the piping passed through with a cutting torch. A leak prevention clamp was installed on the hole that leaked on February 10th. A hot work permit was issued that was signed by the No. 1 Operator and the Shift Supervisor that were involved on February 23rd. The hole in the deck was enlarged with a cutting torch.

Job Discussion on February 22nd

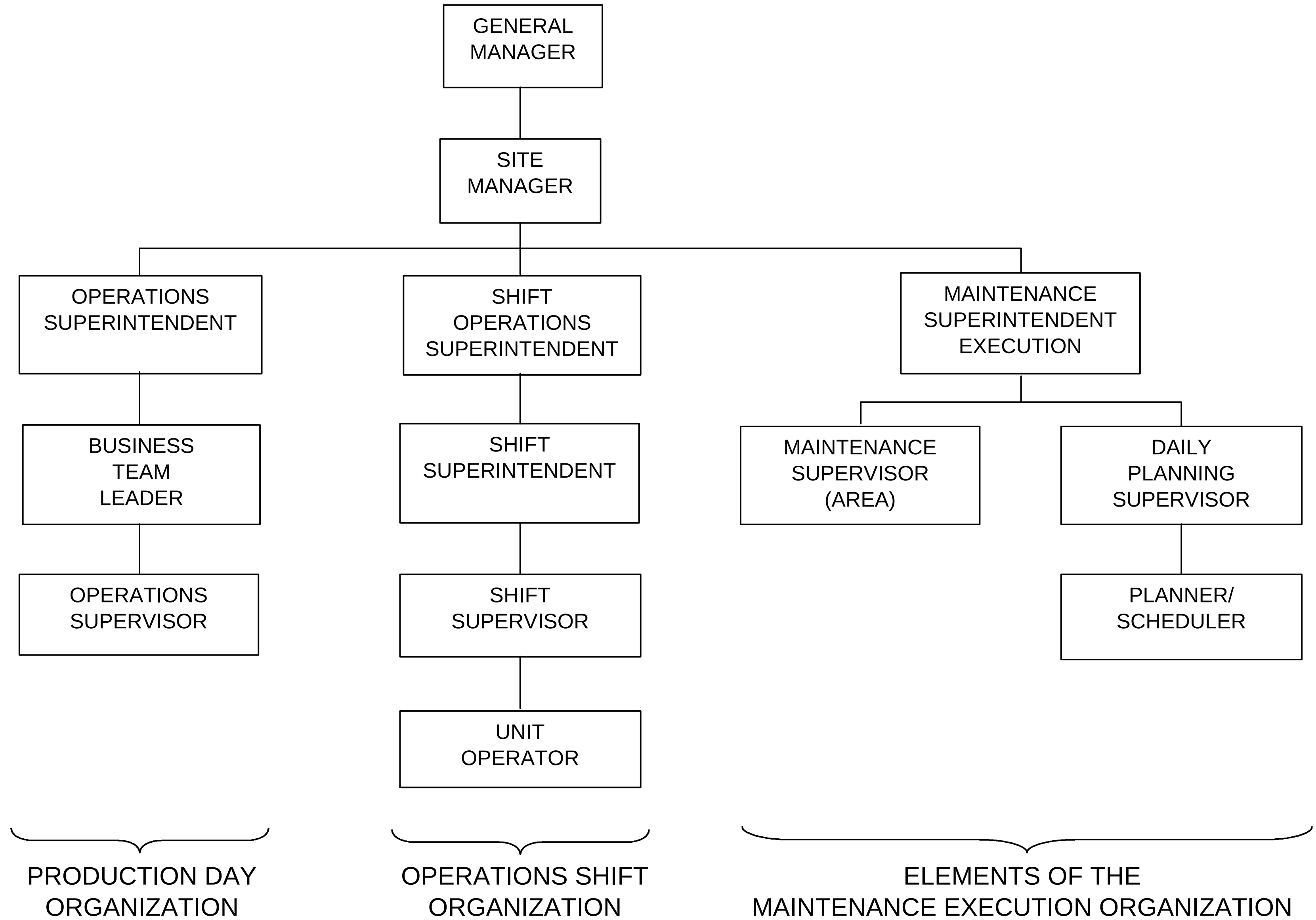
Also on Monday, February 22nd, the Operations Supervisor discussed the extent of work scheduled for the next day with the No. 1 Operator present Monday (and who would be the No. 1 Operator on February 23rd) and the Maintenance Supervisor. The extent of work discussed was to drain and remove the Naphtha Piping. The Operations Supervisor entered into the Permit Readiness Sheet for work to occur on February 23rd: "Bigge, Interstate Scaffold, Tosco and Rust (vacuum truck) personnel to drain and start removal of naphtha draw piping." The Permit Readiness Sheet is an electronic means of informing the Shift Supervisors and operators what job permits are required for the next day. It is finalized by the Operations Supervisor late in the afternoon the day before and transmitted to the Shift Supervisors and operators for the following day's work.

Job Planning

When Tosco managers and supervisors made the decision to replace the naphtha piping with the unit still running, they made a decision, perhaps not knowingly, to dismantle piping containing a large amount of naphtha located directly above several sources of ignition, i.e., the hot surfaces associated with the hot Fractionator and hot associated piping, some of which were above the auto-ignition temperature of the naphtha. The planning involvement that went into this job between February 10th and February 23rd can be summarized as follows:

- Tosco management, and Operations Supervisor (whose job it is to coordinate maintenance activities for operations with maintenance), planning involvement was determining the extent of piping to be replaced and the scheduling priority for completion of the work.
- The Operations Shift Organization was not involved at all in the planning of the work.
- The Maintenance Execution Department made the necessary drawings, assembled all the materials needed to execute the job, and scheduled the work in coordination with the Operations Supervisor.

CHART 4-1
OPERATIONS AND MAINTENANCE ORGANIZATIONS



SECTION 5

EVENTS OF FEBRUARY 23, 1999

Note: All Exhibits referred to are in Appendix A. Valves names, e.g., Valve A, are the names assigned in the exhibits. Exhibit 9 is a scale drawing that shows the relative locations of sites referred to in the following discussion.

Worker Sign-in

On the morning of February 23rd, the crew that was to drain and remove the naphtha line arrived at 50 Unit. About 7:15 AM three Interstate Scaffolding workers signed in. They were to erect and adjust scaffolding as needed for the Tosco maintenance mechanics and Bigge Crane workers. At 7:20 AM Waste Management arrived with two workers and a vacuum truck and signed in. Material from the line was to be drained into the vacuum truck. At 7:40 AM, the two Tosco maintenance mechanics that would assist the operators in draining the line and dismantle the piping signed in. And finally, at 8:00 AM, a Bigge crew of three arrived with a crane and signed in. The crane, which was to lift out pieces of piping, had been scheduled the previous week.

Shift Supervisor Check-in

The Shift Supervisor, in preparation for the 8:00 AM staff meeting he regularly attends, telephoned the No. 1 Operator before 8:00 AM and inquired about the status of the 50 Unit operations. He also asked if there were any problems associated with maintenance activities. While the naphtha line was not specifically discussed, the No. 1 Operator responded that there were no problems. When problems subsequently developed during execution, the No. 1 Operator did not notify the Shift Supervisor.

Work Permit

Piping in hydrocarbon service must be in proper condition so it can be safely worked on, and these conditions should be indicated on the work permit. (The naphtha line should have been prepared as shown in Exhibit 3 before any cold cutting was started.) To comply with both Tosco safety procedures and the Cal/OSHA Petroleum Safety Orders, the naphtha line should have been drained, depressured, steamed out or water washed (as practical) to remove residual naphtha, and slip blinds installed between the flanges at Valves A and B for positive isolation to prevent any leakage through either Valve A or Valve B.

The No. 1 Operator finished preparing the permit that was started by operators on the previous shift. The permit stated that equipment conditions for proceeding with the work were that the system be at zero psig pressure and isolated with double block valves and open bleeders valves. (Please see Appendix C for a description of piping isolation techniques.) Under controlled conditions, two closed and locked block valves in series with a locked open bleeder valve between them (double block and bleed) can be an acceptable substitute for slip blinding. However, neither Valve A nor B has an associated second block valve or bleeder valve; therefore, it was impossible to double block and bleed the naphtha line for isolation. A single closed valve, even locked, is seldom considered an acceptable substitute for a slip blind in the petroleum industry. There was no mention of slip blinding on the work permit. The work permit did not authorize cold-cutting of the line. In addition, the naphtha, due to a small benzene content, is a designated benzene stream. Benzene was not, but should have been checked off on the permit as a Special Hazard that requires Shift Supervisor approval of the permit.

Joint Job Site Visit

Tosco procedures require that the No. 1 Operator who is issuing the permit and the maintenance mechanic who will accept the work permit conduct a Joint Job Site Visit (Job Walk) before either signs the permit. The purpose of the Job Walk is for the No. 1 Operator to explain the hazards of the job to the worker, and to show the maintenance mechanic that required safety measures are in place. The operator and maintenance mechanic should have signed the permit after the Job Walk and only after being satisfied that all safety measures were in place. Both the No. 1 Operator and the maintenance mechanic signed the permit at 8:30 AM before the job walk. In addition, the permit was signed without conditions specified on the permit satisfied.

First Draining Attempt

From approximately 9:00 AM to 9:30 AM, the operators and maintenance mechanics again attempted to drain the piping from the same location as the previous week; this time through an unplugged drain Valve "I" (See Exhibit 5) downstream of the control valve into a half barrel with a hose in the barrel connected to the vacuum truck. During this attempt, the No. 1 Operator in the field had an operator in the control room operate the control valve to various open positions in an attempt to start drainage. This attempt failed.

First Cold Cut

After failing to drain the line, a decision was made to initiate the first cold cut. The No. 1 Operator, the three Interstate Scaffolding employees, the Bigge foreman, and the two Tosco maintenance mechanics proceeded to the top of the naphtha line to make the first cold cut. (All cold cutting was done with a pneumatically driven hacksaw.) The line was in the condition as shown in Exhibit 4. (Since both Valves A and B leaked after February 10th, and the pressure in the naphtha stripper increased from that of February 10th when the line was shutdown, the height of naphtha in the line had increased about 7 ft. more than the level shown in Exhibit 2.)

The Bigge foreman attached a cable from the crane to the piece of pipe to be removed and cold cutting was initiated (see Exhibit 5). At the same time the bolts were removed from the flange connecting Valve A to the piece of pipe and the flanges were separated. (It is possible that when no leakage occurred when these flanges were separated, the workers considered this as evidence that bypass Valve B was not leaking. If so, this was a false sense of security because bypass Valve B could have been wide open and there would have been no leakage at the first cut due to the liquid seal leg.) As can be seen in Exhibit 5, the first cold cut was made about 25 ft. above the level of naphtha in the pipe. During the cold cutting the line was pulled away from Valve A and a blind flange was installed on Valve A. (The deck hole was enlarged the previous day to allow the pipe to be pulled back to install the blind flange.) While the cold cutting was progressing, the Maintenance Supervisor joined the group at the cold-cutting site. As soon as the cut was completed, the crane removed the piece of pipe.

Second Draining Attempt

After the first cold cut was complete, the No. 1 Operator, Maintenance Supervisor and a maintenance mechanic returned to the control valve and cracked open the downstream flange on Valve C (See Exhibit 5), and nothing drained. (The rest of the group remained on the tower in the vicinity of the second cut.) The Maintenance Supervisor next probed between the flanges with a gasket scrapper, but still nothing drained. (Post incident investigation revealed that the piping at the bottom of the "U" was essentially plugged solid as indicated in Exhibit 5).

Second Cold Cut

After the second draining attempt, the Maintenance Supervisor and the No. 1 Operator went up the Fractionator to where the second old cut would be made. The Maintenance Supervisor joined the maintenance mechanic who would make the cut and the Bigge foreman on the deck of the cold cut. The No. 1 Operator joined others in the vicinity. As can be seen on Exhibit 5, the naphtha level in the pipe was about four feet above the second cold cut location. The second cut was initiated and, when the hack saw penetrated the inside diameter of the pipe, naphtha leaked out the sawcut. This leak was not squirting out; it was described by a witness as seeping out.

The Maintenance Supervisor told the maintenance mechanic to stop cutting and to leave the saw in the cut to minimize the leak. The Maintenance Supervisor then told the maintenance mechanic to leave the job site to get a pipe leak clamp, which he did. The Maintenance Supervisor again hammered on the line attempting to locate the liquid level. After hammer testing, and since it was lunchtime, the entire crew came down off the Fractionator. The Maintenance Supervisor, the No. 1 Operator, and a maintenance mechanic proceeded to the stripper deck by the level control valve and discussed the status of the job. Plans were made to drain the line after lunch by spreading the flanges at the bottom of the vertical leg of piping as shown on Exhibit 6. At this time the workers all went to lunch. Before lunch, the maintenance mechanic sent for the leak clamp returned and was seen starting to climb up the Fractionator with the clamp. It is not known whether or not he installed the clamp before he took his lunch break.

Lunch Break

The maintenance mechanics lunch break is from 11:00 AM to 11:30 AM. At this time all involved in the job left the job site. During the lunch break one of the scaffolding workers was assigned to another job.

Third Draining Attempt

After lunch, a Tosco maintenance mechanic, the Bigge foreman, and two Interstate Scaffolding workers returned and climbed the Fractionator to site of the second cut. The other Tosco maintenance mechanic set up to drain the line from the flanges at the bottom of the vertical leg. (See Exhibit 6) During all activities after lunch neither the No. 1 Operator nor the Maintenance Supervisor were present. The No. 1 Operator was in the control room and the Maintenance Supervisor was elsewhere in the refinery. The maintenance mechanic at the flange started to successfully drain the line into a plastic pan with a hose in it connected to the vacuum truck. We believe that the maintenance mechanic at the second cold cut location resumed cutting when the naphtha level was below the cut. We believe cold cutting was resumed because the depth of cut was much greater that described as being the depth before lunch. The leak clamp sent for before lunch was found uninstalled at the cold cut site. The maintenance mechanic could have installed it before lunch and removed it after lunch for resumption of cold cutting.

Naphtha Release and Fire

Post incident investigation revealed that the disc and seat ring of bypass Valve B, a globe valve, were badly worn due to a combination of erosion and corrosion. A tight compression fit of the disc and seat ring is required to prevent leakage through the valve. In this case, the disc and seat ring met at only two points. The area of the circumferential gap area was equivalent to the area of a one and one-half inch diameter hole. The actual flow rate through the jagged circumferential gap would be less than through a one and one-half inch hole, but was large enough to result in the release mechanism described below. The valve exhibited significant leakage during post incident testing by Tosco.

As the naphtha was draining into the vacuum truck, the naphtha in the liquid seal leg (in the vertical piping next to the Naphtha Stripper) was flowing through the Valve B and the liquid seal leg was dropping and growing smaller (as shown in Exhibit 6). The seal leg dropped to the point that there no longer was a liquid seal (as shown in Exhibit 7). At this point the pressure in the naphtha stripper was sufficient enough to lift the remaining column of naphtha in the vertical leg by the Fractionator. As the maintenance mechanic continued to drain the line, naphtha vapors flowed through the bypass Valve B in sufficient volume and force to mix with and lift the naphtha liquid up the vertical section of pipe next to the Fractionator (see Exhibit 8). Naphtha was released at three locations: out the flanges where the maintenance mechanic was draining the line, out of the second saw cut, and out the open top of the piping at the first cut. The Bigge crane operator observed naphtha spraying over the railing of the deck where the second cut was being made and left the crane and ran toward the control room. The crane operator said when he first looked back, he saw ignition between where the maintenance mechanic was draining the line and the top of the tower and a flame front going both up and down. After a couple more steps, he looked back and saw a fireball. The fire burned for about twenty minutes. Tosco initiated their emergency response. The four workers on the Fractionator died from their burns. The maintenance mechanic draining the line survived, but suffered serious burns and permanent injuries.

SECTION 6

INVESTIGATIVE PROCESS

This incident investigation was conducted in a cooperative effort by Contra Costa Health Services, CalOSHA, and the Chemical Safety and Hazard Investigation Board. CCHS and CalOSHA started collaborating on the day of the fire, February 23rd, and the Chemical Safety and Hazard Investigation Board joined the investigation on February 26th. From the onset of the investigation the three agencies freely and fully cooperated with each other on the fact finding portion of the investigation. Each agency independently performed analysis of the findings according to their statutory authority. CCHS would welcome the opportunity to collaborate with CalOSHA and/or the Chemical Safety Board on future investigations.

The investigative process included interviewing Tosco and contractor employees, reviewing Tosco documentation and operating data, and examining and testing physical evidence.

INTERVIEWS

With few exceptions that were known to all the agencies, all interviews were joint agency interviews. All interviews were conducted at Tosco with the exception of the interviews of the Bigge Crane and Interstate Scaffolding employees, which were conducted at their attorneys' office. We were able to interview all 38 individuals we requested with the exception of the maintenance supervisor for the job. The private attorney retained by the maintenance supervisor declined to make her client available due to a potential for criminal proceedings. Interviews with nine other key individuals were delayed several weeks while they obtained private attorneys. These included (1) the Avon Refinery Site Manager, (2) the Operations Supervisor, (3) the Business Team Leader, (4) the Operations Superintendent of the Production Day Organization; (5) the Shift Supervisor on shift during the fire, (6) the Shift Superintendent on shift during the fire, (7) the Shift Operations Superintendent of the Operations Shift Organization; (8) the maintenance Daily Planning Supervisor, and (9) the Superintendent of the Maintenance Execution Organization. (Please refer to Chart 6-1) Tosco and/or private attorneys for the individuals were present at all interview except for February 25th interview of the No. 1 Operator on shift during the fire, who declined Tosco legal representation. We were unable to do subsequent interviews of this No. 1 Operator because he retained private attorneys who declined to make him available. We certainly regret not being able to interview the Maintenance Supervisor who directly supervised the workers at the job site during the morning of February 23rd or to re-interview the No. 1 Operator. We believe they could possibly explain the reasoning for decisions made on February 23rd to proceed with dismantling the line before it was properly prepared, and to continue dismantling the line when a hazardous situation was evident i.e., the leaking second cold cut.

DOCUMENT REVIEW

The combined agencies requested 249 documents for review. Copies of documents requested by any agency were given to all agencies.

PHYSICAL EVIDENCE

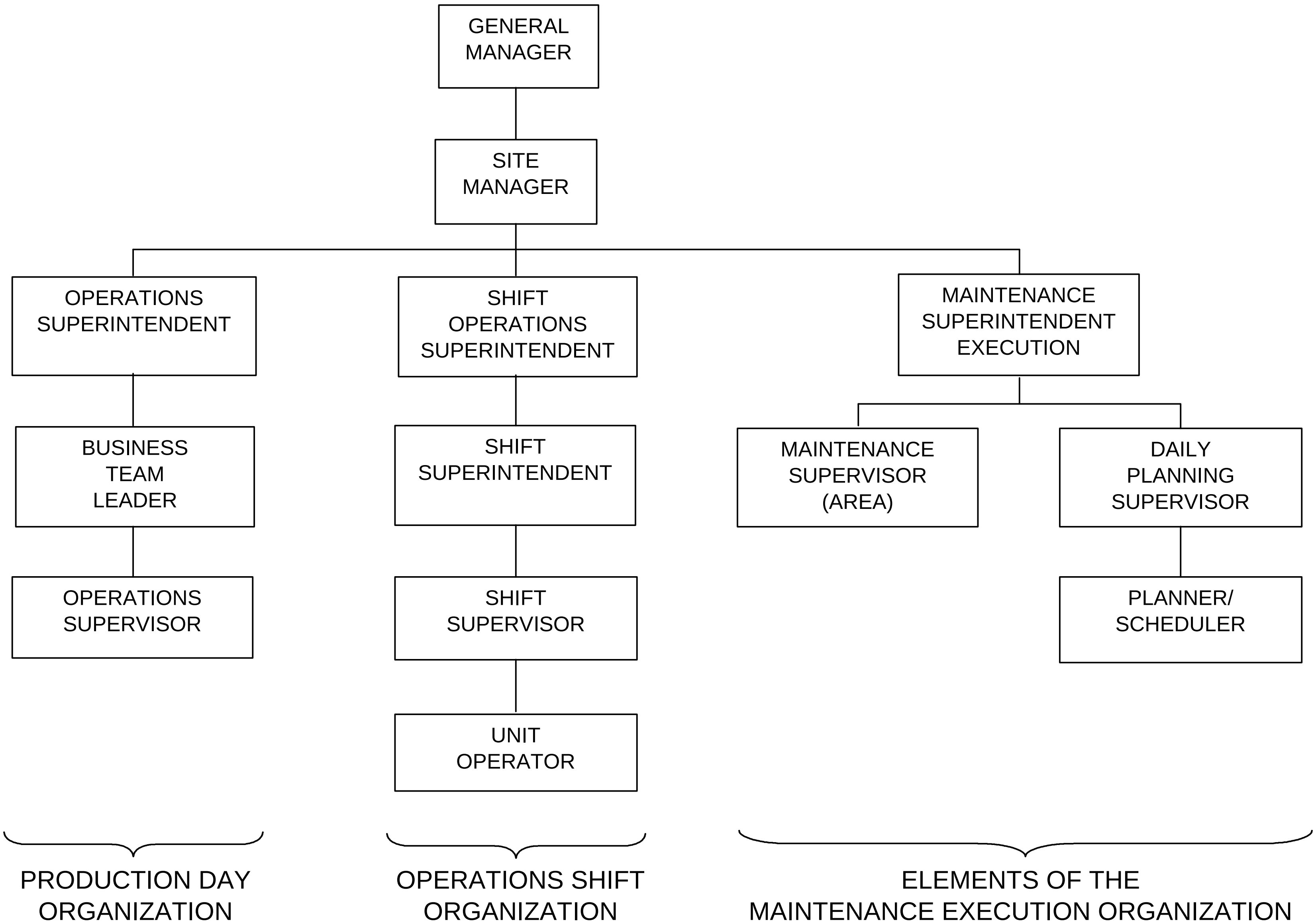
CalOSHA had control of the incident site and the collection and testing of physical evidence. CalOSHA cooperated with the other agencies to be sure the other agency needs were met on the control of the incident site and the collection and testing of physical evidence. The physical evidence included all the naphtha piping between Valve A up to and including the bypass Valve B and block Valve E. The physical evidence also included samples of the black tarry-like sludge plugging the control valve manifold. CCHS was interested, as were the other agencies, in the corrosion mechanism that caused the leak of February 10th, even though the leak of February 10th is not included in the scope of the CCHS root cause investigation. CCHS was also interested in the test results for the leaking bypass valve and the sludge that caused the drain valve plugging. The test results show that:

- The leak of February 10th was cause by ammonium chloride corrosion of the pipe wall
- The sludge plugging the bottom section of the line was comprised of iron oxide, and sulfur and chloride compounds, i.e., probably products of corrosion

- The significant bypass valve leakage was cause by corrosion and erosion of the valve seat ring and plug due to the valve being in service rather than normally closed.

These test results are discussed in Appendix B.

CHART 6-1
OPERATIONS AND MAINTENANCE ORGANIZATIONS



SECTION 7

BARRIER ANALYSIS

One method used to conduct the incident investigation is the technique of barrier analysis. A barrier analysis examines any potential controls, or barriers, that would have prevented an unwanted event from occurring. Studying the nature of the failure of these barriers is part of the incident investigation process.

In examining an incident, the primary hazard must first be identified. The definition of hazards can be simplified down to an uncontrolled flow of energy, be it kinetic, potential, chemical, thermal, electrical, radiation, etc. In an incident scenario, the target, which is either people or objects, comes in contact with the hazards, which are meant to be contained in the system. Barriers are any physical, administrative, or supervisory/management controls that prevent the hazard from reaching the target.

Examples of the barriers are:

- Physical Barriers: Adequate piping integrity, personal protective equipment, fire fighting systems
- Administrative Barriers: Adequate equipment design, proper following of procedures, proper work practices and operations
- Supervisory/Management Barriers: Proper supervision, proper management oversight

For an incident to occur, barriers can either not be in place, or be in place but fail.

In the case of the Tosco fire, the primary hazard was the uncontrolled release of flammable hydrocarbon. The targets were the Tosco employees and contractors working on the naphtha piping at the time of the hydrocarbon release. This barrier analysis is the result of evaluating the effectiveness of Tosco's barriers in place at the time of the incident.

On one level of analysis, it was a barrier failure that resulted in the fire on February 23, 1999. The failures of the barriers listed in the following table are those that CCHS believes caused or contributed to this incident. The effectiveness of the barriers was analyzed and, from the investigation of the evidence available, a list of failures for each barrier was generated.

The table below lists the barriers that, had they either been in place or, if in place, had failed to prevent the incident. Each barrier is listed with a brief description of the intent of the barrier (in italics).

A description of the failure or failures of the barriers is also listed.

A discussion of some of these barrier failures is covered in Causal Factors Analysis, Section 8.

BARRIER	FAILURE
CLEAR LINES OF RESPONSIBILITY *Clear lines of responsibility allowing for accurate and complete transfer of information up and down chains of command.*	With two separate Operations chains of command, the Shift Organization and the Day Organization, conditions known in the Shift Organization were not necessarily passed along to the Day Organization, and vice versa.
	On day shift, operators received work direction from the Operations Supervisor, Shift Supervisor, Business Team Leader, and the Operations Superintendent.
	Some operators responded that their supervisor was the Business Team Leader, not the Shift Supervisor. Others said it was the Operations Supervisor. There existed confusion among the Operators as to who was their supervisor.
	Frequent changes in the organization – three changes in management/supervision/organizational structure in the past two years
PROPER COMMUNICATION *Reporting of hazards of and changes in the system to allow Managers, Supervisors, Operators, and Contractors to properly respond to significant information.*	Both the Business Team Leader and the Operations Supervisor were aware the drain valves were plugged (as early as the Wednesday prior). Operations Supervisor ordered that the valves be drilled out; the drilling failed. Neither the Business Team Leader nor the Operations Supervisor followed up on whether or not the valves were unplugged and the system drained.
	Operations management indicated they did not know the Operators couldn't drain this line.
	Line leaked at least twice more from original leak location but no mention was made in any logs. This leakage was an indication of Valve A leak-by.
	In an operating plant, a naphtha leak is a significant event. During the subsequent leaks, there were no communications from operators to Operations supervision or management. There was no action taken to investigate the cause for the subsequent leaking.
	Shift Supervisor assisted in cinching valves after one subsequent leak, but no mention was made in any logs.

BARRIER	FAILURE
	Naphtha Stripper level was pumped out at least six times by operators, after all inlet valves were initially closed. A Shift Supervisor noted this in the Night Notes for February 13th, referring to the first pump out on February 13th, but no subsequent actions were taken. The necessity to pump out the Stripper indicated both the top valve and the control valve manifold valves were leaking by.
	The pipe spool (a short piece of pipe between valves D and E) that was removed on February 19th was found to contain some sludge. Valve D was also plugged, while valve E contained a small amount of sludge. Operators, maintenance mechanics, and the Maintenance Supervisor knew this, but this information (the possibility of more of the line being plugged) failed to be relayed to Operations management.
	Surviving Bigge and Interstate Scaffolding workers said they were not told that naphtha was still in the line.
ADEQUATE SUPERVISION *Adequate supervision allows for clear definition of the responsibilities of all employees. It ensures that assigned job tasks are completed. It also provides an outlet for workers' questions or difficulties encountered with the job.*	Operations Supervisor's and Shift Supervisors' job descriptions include "ensuring maintenance work is prepared properly". Neither the Operations Supervisor nor the Shift Supervisor on shift that morning recognized this as one of their job functions in their interviews.
	This job was originally of high enough importance to have been brought to Site Manager's attention, but no managers or supervisors were sufficiently involved in implementation and safety issues regarding the job.
	Managers stated that no one brought any problems to their attention; however, there was no pro-active questioning or work direction on the part of the managers regarding job execution or safety.
	There was less than adequate additional job plan or operating work guidance or supervision before or during work (apart from established Safety Orders and Procedures).
	No Operations supervision was present for execution of work; however, the Maintenance Supervisor was present.
	Less than adequate maintenance supervision for execution of work
PROPER JOB PLANNING	No blind list in work package.

BARRIER	FAILURE
Proper job planning is required for safe completion of the job by defining the scope, assigning responsibilities, outlining tasks, and establishing a method for follow-up.	Operators are responsible for preparing blind lists. This was not done, nor was there any Operations supervision follow-up to ensure it was done.
	There were inconsistent responses during interviews on who had overall responsibility for this job.
	There were no additional written work plans or procedures (apart from established Safety Orders and Procedures).
	There were inconsistent responses during interviews on whose responsibility it was to write procedures (in special circumstances to supplement standard safety procedures). Managers and supervisors either stated they did not know, or cited the Operations Supervisor.
	Crane was scheduled on February 19th for February 23rd and was on site before line was adequately prepared for removal.
LINE PREPARATION *Line preparation is necessary to ensure all hazardous material is removed and the system is safe for maintenance.*	Line was not drained and isolated positively by blinding prior to cold cutting was initiated on February 23rd.
FAMILIARITY WITH SYSTEM *Adequate familiarity with this system allows for complete isolation and the safest method for line removal.*	The line was drained from an inappropriate location (i.e., a flange located next to high temperature systems), while a bleeder valve in a safer location downstream was not used.
	A maintenance mechanic indicated the Maintenance Supervisor was aware of the bleeder valve located upstream of the control valve manifold during preparation of the piping replacement drawings. Instead, he directed the mechanics to drain from an upstream flange, located by the fractionation tower, above potential ignition sources.
	The level control valve 4-inch bypass globe valve had been partially open during operation for some time, which, according to laboratory results, contributed to the corrosion and erosion of the valve seat and disc. It was relied upon by Operators to provide isolation for the naphtha line.

BARRIER	FAILURE
PROCEDURAL BARRIERS *Proper procedures ensure that activities covered by the respective procedures are all conducted safely.*	The procedures described below were not followed. If the procedures had been followed, this incident would not have happened.
S-5 Departmental Safe Work Permit *Ensures that the first steps of maintenance activities are prepared properly.*	
I. ALL work performed by personnel (except shift operating personnel) in the SFAR-Avon Refinery operating areas will be authorized by a qualified operator.	The permit signed on the morning of February 23rd for this job did not authorize cold cutting of the naphtha draw piping.
III-F. Special hazards require permit to be signed by Shift Supervisor	Because the naphtha draw system is designated as a benzene stream, the Shift Supervisor's signature was required on the Safe Work Permit. The Shift Supervisor did not review and sign the Safe Work Permit, (even though he knew that this line was designated a benzene stream, he did not believe that his signature was required for this job).
VII-B PERMITTING WORK IN AN OPERATING AREA	
Before performing work requiring a permit in an operating area, the work must be authorized, on the appropriate permit, by the Responsible Operator.	
Before issuing the permit:	
1. The operator must properly prepare equipment for maintenance; be sure equipment is depressured , drained and flushed, or purged and inactivated/locked out as per S-10; and perform appropriate gas checks	The piping was locked out, but the remaining requirements (i.e., depressured, drained and flushed, or purged) were not complied with.
2. Together, the operator and the worker (*maintenance mechanic*) will conduct a JOINT JOB SITE VISIT and inspect the site; identify and examine the specific equipment involved; review the current conditions or situation; and review the worker's plan to perform the work.	A JOINT JOB SITE VISIT (job walk) was done, but after both the Operator and the maintenance mechanic signed the permit. We do not know what was discussed.
3. The operator will explicitly instruct the workers (*maintenance mechanics*) about any hazards; PPE required; and any other	A JOINT JOB SITE VISIT (job walk) was done, but after both the Operator and maintenance mechanic signed the permit. We do not know what was

BARRIER		FAILURE
	special procedures which may be required (benzene requires special PPE)	discussed. Both an operator and a maintenance mechanic signed the permit even though the required conditions were not met.
4.	While they are at the job site, the operator will show the workers (*maintenance mechanics*) that equipment is depressured, drained and or purged and inactivated/locked out as per Safety Order S-10	As stated above, the piping was locked out, but the remaining requirements were not complied with.
(The above actions are **mandatory** prior to the operator signing the permit)		
VII-C	ISSUING THE PERMIT	
2.	The worker (*maintenance mechanic*) must read the completed permit and sign it on the "worker" line. By signing the permit, the worker indicates agreement with the conditions that have been set and that proper communications have taken place.	A maintenance mechanic signed the permit even though the required conditions were not met.
VII-D	WHILE THE JOB IS IN PROGRESS	
2.	If anyone discovers unauthorized work in progress, he or she shall stop the work, advise the worker (*maintenance mechanic*) of the proper work procedures, and notify the Responsible Operator. The Responsible Operator then notifies the Shift Supervisor of the incident. The Shift Supervisor will follow up as necessary with the appropriate department and level of investigation.	On February 23rd, the No. 1 Operator, the maintenance mechanics, and the Maintenance Supervisor should have known that work was proceeding in violation of procedures (e.g., line not drained, no blinds installed, etc.) and no one stopped the work.
		Several interviewees stated they had stop-work authority for maintenance jobs, indicating there was common knowledge of this. A maintenance mechanic stated he was concerned about working on an undrained line, but failed to tell anyone else of his concerns. In addition, on February 23rd, the No. 1 Operator expressed concerns about the job, but failed to notify his supervisor.
S-10 Control of Hazardous Energy *Ensures that hazardous material releases do not occur.*		

BARRIER	FAILURE
III-A. Energy Isolating Devices include slip blinds and block valves with locks and chains or other devices which positively prevent the opening or closing of the valve	In this instance, a globe valve (the bypass) was used as a block valve. Laboratory analysis of the glove valve indicates that continued use of the globe valve (i.e., operating continually in bypass mode) for prolonged periods of time contributed to the corrosion/erosion of the globe valve seat. This damage prevented the globe valve from providing any positive isolation.
	We could not determine if there was intent to blind the naphtha line. No slip blinds were found at the job site at 50 Unit. No blind list was found.
VI Piping shall be isolated using energy isolating devices (mechanical devices that physically prevent the transmission or release of energy)	Cutting was performed on line before the bypass valve was blinded.
VI Operations will block and bleed line pressure to 0 (where practical) before blinding	Line was blocked with valves, but not drained to ensure the line was depressured.
VI Operators will physically point out the correct blinds and energy isolating devices	No blinds were installed.
S-29 Benzene *Ensures that employee contact with benzene is minimized.*	
This Safety Order identifies 50 Unit naphtha draw system as a benzene stream (>0.1% by volume).	The naphtha line was not treated as a benzene stream during any of the maintenance actions.
Production (Operations) has the primary responsibility of establishing and monitoring a benzene-regulated area.	This was not performed.
Production must contact Industrial Hygiene regarding the work to be done	This was not performed
Material in the system must be drained to a closed system.	The initial attempts at draining were going to the sewer.
Specify in writing on the Safe Work Permit all required precautions for benzene streams	This was not performed.
Demarcate the area with benzene warning tape	This was not performed.
An Operations supervisor must sign safe work permit.	This was not performed. (See above barrier under Safety Order S-5 Departmental Safe Work Permit, Section, III-F.)

BARRIER	FAILURE
PFFE005 Portable Power Pneumatic Hack Saw *Ensures proper operation of this piece of equipment.*	
Maintenance must walk job through with Operator and make sure pipe to be cut is drained and flushed as needed	Cold cutting was initiated by maintenance knowing line was not drained.
S-36-10 Blinding *Ensures that hazardous systems are completely isolated for maintenance.*	
Overall: Clear assignment of roles and responsibilities in written procedures and safety orders	Blinding procedures are less than adequate in assigning responsibilities for ensuring procedures are followed. Blinding procedures state that the Operations Department is responsible for developing a written blind list. No specific title or position is assigned this responsibility.
Prior to permitting work requiring use of blinds, Operations Department shall develop a written blind list.	No blind list was prepared.
When preparing for cold work which has the potential for allowing an uncontrolled release of hydrocarbons (at temperatures at or above flash point), equipment shall be blinded.	The naphtha was above its flash point, therefore blinding was required.
Unless an exception exists where blinding would involve greater risk than the work to be performed, blinding is required. Written approval by appropriate Operations and Maintenance Supervisors is therefore required for not blinding.	The exception would not apply to this job. No written document exists.
If performing cold work without blinding, the following is required:	
• work must be performed to completion;	The work crew took a lunch break, leaving the site unattended.
• block valves closed tight without excessive leakage and open vent to reduce pressure to 0 psig;	Since the line was not drained, valve leakage could not be determined. There was not an open vent.
• bleeder valves shall be checked to ensure they are not plugged and are functioning properly;	Bleeder valves were known to be plugged.
• bleeders shall be tagged in the open position	Bleeder valves were closed and not tagged.

BARRIER	FAILURE
S-36-9 Safety Task Analysis Risk Reduction Talk (S.T.A.R.R.T.) **S-25 Job Safety Analysis (JSA)** *Describes procedures for ensuring that maintenance safety issues are addressed before beginning a job.*	
A S.T.A.R.R.T. card, required to be filled out prior to all work that requires a permit, addresses safety concerns that maintenance employees may encounter during the job. (A S.T.A.R.R.T. card was collected as evidence after the incident, however it was damaged beyond the ability to recover the information it contained.)	S.T.A.R.R.T. cards do not cover what is required to adequately prepare the line for maintenance.
	A S.T.A.R.R.T. card would not have adequately indicated the process hazards associated with this job. Contractors on the job the morning of February 23rd stated that they were not told there was naphtha in the line.
A JSA is required when a job has the potential for frequent or severe injury.	No JSA was performed. (Specifically, a JSA may not have been required for this job, but no other safety analysis was performed to determine the possible process hazards associated with this job.)
California Petroleum Safety Orders *Lists multiple requirements for operating and maintaining petroleum refineries safely.*	
Before opening lines or other equipment, the pressure shall be reduced to atmospheric or as near atmospheric as practical.	Failure to drain prohibited the line from being depressured.
Employees shall be informed of the hazards due to the contents of the lines or equipment and instructed as to the necessary precautions to be taken.	Employees (maintenance and contract workers) were not notified that this line was designated a benzene stream.
Lines containing flammable liquids shall be emptied of their contents, washed out, or steamed before being opened, as is practical	Failure to drain prohibited the washing or steaming out of this line.
Precautions shall be taken to prevent ignition by eliminating or controlling sources of ignition before opening lines where flammable liquids may be present.	After the initial attempt to drain from the control valve on the Stripper Deck, there was no evidence of precautions being taken on the hot surfaces below the flange, which were sources of ignition.

SECTION 8

CAUSAL FACTOR ANALYSIS

An incident investigation should answer three questions: what happened, how it happened, and why it happened. Causal factor analysis, including identifying root causes addresses why an accident happened. Section 5 described what happened and how it happened. The objective of causal factor analysis is to identify the causal factors or potential causal factors of the fire. The methodology used is based on that described in the U.S. Department of Energy Workbook “Conducting Incident Investigations,” Revision 1 dated November 21, 1997.

TYPES OF CAUSAL FACTORS

There are three kinds of causal factors covered in this analysis:

- Direct cause
- Contributing causes
- Root causes

The direct cause of an accident is the immediate event or condition that caused the accident.

Contributing causes are events or conditions that collectively increase the likelihood of an accident but that individually did not cause the accident.

Root causes are the causal factors, including management systems, that if corrected, would prevent recurrence of the accident. Root causes can include management system deficiencies, management failures, improper worker actions, inadequate competencies, accepted risks performance, errors, omissions, non-adherence to procedures, and inadequate organizational communication. Simply stated, the root causes answer the question “why did the accident happen?” Note that the definition neither limits root causes to management activities nor precludes workers’ activities from being root causes.

However, the DOE methodology states the following conditions must exist for the root cause of an accident to be found at the worker level (In this case worker level would be 50 Unit operators including No. 1 Operators, Tosco mechanics, and the Bigge Crane and Interstate Scaffolding employees.)

- Management systems were in place and functioning, and provided management with feedback on system implementation and performance.

- Management took appropriate actions based on the feedback.

- Management, including supervision, could not reasonably have been expected to take additional actions based on their responsibilities and authorities.

It's important to put this accident into context. This accident was not the result of an unexpected operational upset or an unexpected equipment failure in 50 Unit. This accident happened while workers were dismantling a piping system that had been shutdown for replacement two weeks earlier. This piping replacement was not a high priority rush job. The dismantling was scheduled for February 23rd and installation of the replacement piping was scheduled for February 26th. Beginning immediately following isolation the leak of February 10th, the execution of this job was subject solely to human actions at the operator and mechanic level and various management and supervisory levels at Tosco. There were also standard Tosco safety procedures that applied to the safe execution of the job.

In the following discussion, CCHS argues that though serious and significant contributing causes were found at the worker level, worker actions were not the root cause because management systems and actions were less than adequate and did not fulfill the above criteria for finding root causes at the worker level.

DIRECT CAUSE

The direct cause of the fire was naphtha released from the naphtha piping that ignited off hot surfaces on the Fractionator which were above the autoignition temperature of the naphtha.

CONTRIBUTING CAUSES

1. Naphtha was released because the naphtha line was not properly prepared for maintenance in compliance with Tosco safety procedures and the State of California Petroleum Safety Orders.

This is a serious and significant contributing cause, because if Tosco safety procedures had been complied with on the day of the fire, the fire would not have occurred. These safety procedures reflect what is common practice in the refining industry for preparing piping for maintenance work. This non-compliance is tabulated in Section 7, Barrier Analysis. Before cold cutting started, isolation valves should have been locked and tagged, which was done, and the line then should have been, but was not:

- Drained
- Depressured
- Washed or steamed out
- Blinded (Slip blinds installed for isolation)

After securing the isolation valves, the essential first step for accomplishing all of the above is draining the line. In this case, cold cutting and removing the first section of piping was initiated without the line being drained. Draining was critical for two reasons: First and obvious, draining would have eliminated most of the naphtha, and second, only by draining the line could the operators have verified that the isolation valves were leak free, i.e., that there was no flow through the closed valves. This would ensure that the line was depressured. Blinds cannot be installed unless piping is both drained and depressured, i.e. block valves do not leak. This accident would not have happened if the bypass valve had been blinded. However, because the bypass valve was leaking significantly, a blind could not have been installed. If the line had been drained, the fact that either the top block valve or the bypass valve (or both) were significantly leaking would have been discovered. With knowledge of this valve leakage, CCHS assumes that Tosco would have shutdown the entire 50 Unit to safely replace the naphtha line. As described in Sections 4 and 5, Tosco made efforts to drain the line before proceeding to cold cut, but when these efforts failed, decided to proceed without draining.

The State Petroleum Safety Orders also require that precautions be taken to prevent ignition by eliminating or controlling sources of ignition before opening lines or equipment where flammable liquids or vapors may be present. In this incident, there was no evidence of any precautions being taken on the hot surfaces beneath the naphtha line that were sources of ignition before cold cutting started.

2. Stop-Work authority not exercised:

This is a serious and significant contributing cause because if the workers and maintenance supervisor had exercised their stop work authority, the fire would have not occurred. Section D.2 of Safety Order S-5, Tosco's procedure that covers Safe Work Permits, sets forth the authority for anyone (including operators, mechanics and supervisors) to stop unauthorized work in progress, which includes maintenance work being done in non-compliance with procedures. It became clear during interviews that Tosco employees recognize that they have this authority. The cold cutting proceeded in clear non-compliance with procedures and neither the No. 1 Operator, the Tosco mechanics nor the Maintenance Supervisor stopped the job.

3. Line plugging

Plugging of the piping at the bottom of the "U" is a contributing cause, because if the line was not plugged, it could have been drained. Draining the line would have revealed that valves were leaking ad the line could not be depressured.

4. Uncommunicated or unrecognized warning signs.

Managers and operating supervisors stated that the warning signs cited below were not known by them. Had management or operating supervisors been aware of these warning signs, they could have reacted to the information by getting involved in the safety aspects of the job.

A. Valve leakage

Between February 10th and February 23rd, there were events in the 50 Unit that were warning signs that clearly indicated that there were problems with the valves leaking. These events and lack of communication are described in Section 4 and are the subsequent leaks of February 13th and 17th, and the necessity of pumping out the Naphtha Stripper six times on February 13th through 14th. The leaks were clear indication that Valve A was leaking. The liquid filling the Naphtha Stripper necessitating the pumpouts of February 13th and 14th could conceivably have come only through Valve A and valves at the control valve manifold, Valve B and/or Valves C, D, and E. This was a clear indication that valves were leaking. The significance of valve leaking is that the line could not be depressured and blinds installed. Consequently, the job could not safely be done with 50 Unit operating.

B. Drain valve plugging

As described in Section 4, both the Business Team Leader and the Operations Supervisor were informed by operators that the drain valves were plugged. Neither followed up to find out whether or not the drain valves had been unplugged. This is a contributing cause because had they found out the drain valves could not be unplugged because the drill cable broke, they should have become involved in job preparation.

C. Sludge in line

As Described in Section 4, sludge found in the piping was not reported to managers and operating supervisors (the maintenance supervisor was aware of the sludge on February 19th). This is a contributing cause because managers or operating supervisors may have become involved in job execution had they known about the sludge and the possibility of the sludge causing line plugging.

5. Two operating organizations with responsibility and authority over 50 Unit.

When the incident occurred, two operating organizations had responsibility and authority for 50 unit. These are shown on the organization chart, Chart 6-1. The Production Day Organization was responsible for planning operations and maintenance, while the Operations Shift Organization was responsible for the execution of the operating plans and maintenance. The operators formally worked for the Shift Supervisors in the shift organization, but in reality, the Shift Supervisors and all levels in the Production Day Organization, particularly the Operations Supervisor, gave the operators direct work direction. Some operators were not clear on who their supervisor was: when asked, the most common answers were the Business Team Leader or the Operations Supervisor, not the Shift Supervisor. CCHS believes that having two organizations responsible for 50 unit and exerting authority over the operators could have contributed to the accident as follows:

- The warning signs cited above were possibly not reacted to by the first line supervisors due to this split responsibility and authority. Each organization could have expected the other to have and take action on the information.
- The Shift Supervisors did not get involved at all in the execution of the naphtha line replacement, and stated they would have gotten involved only if asked to by the Production Day Organization. The Production Day Organization stated the operators were responsible for the safe execution of the job and did not get involved in job execution. This left the changing crews of operators to fend for themselves on a job that should have had someone in operations supervision in charge and coordinating the job on a continuous day-to-day basis.

6. Job scheduling

In CCHS's opinion, the line should have been fully prepared for dismantling before the crane and scaffolding workers arrived on the job site. It is possible, but there is no evidence to the effect, that the presence of the crane and it's three man crew plus the three scaffolding workers on the job site exerted pressure on the decision to proceed without draining the line.

7. Non-conformance with benzene safety practices

A stream that contains more than 0.1% benzene falls under CalOSHA regulations that require specific precaution be taken to prevent worker exposure to the stream. Tosco procedures designate the naphtha stream as falling under these benzene regulations. The Tosco procedures require that in addition to an operator a Shift Supervisor also sign a work permit for work on the naphtha stream that could involve worker exposure. This was not done for work that took place on February 23rd, nor was done for any other work done between February 10th and February 23rd. This is a contributing cause because had the procedure been followed, a Shift Supervisor would have signed the permit for the drilling out of the plugged drain valves on February 18th and removing the section of piping on February 19th. This would have made the Shift Supervisor aware that there were problems draining the line. Also, had the Shift Supervisor signed that permit on February 23rd, he should have noticed that the permit did not adequately cover the proper preparation of the line for dismantling.

8. Unused drain valve

There was a bleeder valve in the piping between upstream of the control valve manifold that was not tried for draining the line. This is Valve H on Exhibit 6. Post incident investigation showed that Valve H was lightly plugged and easy to clear. Had this valve been used to drain the line prior to February 23rd, or on February 23rd before disconnecting the line at Valve A, the valve leakage described above probably would have been safely discovered.

9. Control of ignition sources

Ignition sources were not controlled as required by the State Petroleum Safety Orders. Adequate control of the hot surfaces would have prevented ignition of released naphtha.

ROOT CAUSES

The situation at the start of work on February 23rd can be summarized as follows:

- Draining attempts had been unsuccessful. This was not communicated to managers and operating supervisors.
- Warning signs that clearly indicated valve leakage were not known by management or operations supervisors.
- The operators had received no work direction to supplement Tosco standard safety procedures.
- Managers and operating supervisors were not aware that the line was about 75% full of naphtha.

Referring back to the conditions required to find root causes at the worker level:

Root Cause No. 1:

Management systems were not in place and functioning to provide management with adequate information regarding the safety of the job.

Tosco management did not receive the information that should have caused management to react and assume a leadership role in safely preparing the line for maintenance. Tosco management stated that they were not informed that there were any problems. Specifically:

- Tosco management and first line supervisors did not know that the operators could not drain the line,
- Tosco management did not know that bleeder valves were plugged and that an attempt to drill them out failed,
- Tosco management and first line supervisors did not know that the line twice leaked again indicating that Fractionator Valve A was leaking,

- Tosco management and first line supervisors did not know that the line was reported by operators as being "full",
- Tosco management did not know that the Naphtha Stripper had to be pumped out indicating leakage of the top Fractionator valve and valves at the control valve manifold,
- Tosco operating management did not know of the sludge found in the piping causing the drain valves to be plugged.

Root Cause No. 2

Management systems were not in place to ensure that managers and first line supervisors take appropriate actions that they should have, based on their responsibilities and authority.

Management and supervisors cannot be expected to get involved in all maintenance activities in 50 Unit. However, Tosco management systems should expect manager and supervisors to recognize those maintenance activities where they should be proactive in exerting leadership and authority to ensure that a particular job is safely executed. Managers and supervisors should not assume a job is routine without first considering the safety aspects of the job. In CCHS's opinion, because this job involved dismantling of a naphtha line located directly above sources of ignition, operations managers and supervisors should have become involved in considering the safe execution of the job from the beginning. Operations management should have ensured that plans were made and communicated to the operators on how to safely prepare this line to be dismantled. An individual operations supervisor should have been made responsible for preparing a plan and following the execution of the plan. In this case, it appears that nobody in operations took charge of the job or responsibility for planning safe execution of the job. CCHS believes that had operations management become involved early:

- Management would have quickly recognized that the line was almost full of naphtha presenting a hazardous situation meriting their attention preparation of an execution plan.
- By following up on progress in executing the plan, management would have been aware of all the problems encountered in draining the line and possibly come up with alternative draining methods. One Tosco manager stated "there is always a way to

drain a line." This may not be 100% correct, but there were options not tried that may have been successful.

- If an alternative draining method had been successful, Tosco would have realized at least one valve had significant leakage. This turned out to be the bypass Valve B. At this point CCHS assumes that Tosco management would have shutdown the entire unit to replace the piping.

SECTION 9

RECOMMENDATIONS

RECOMMENDATIONS ADDRESSING ROOT CAUSES

The two recommendations on management systems below are complementary: one addresses effective communications between the shift organization, supervisors and management so that management and supervisors can be reactive, and the other involves the responsibility and authority of managers and supervisors to be proactive in appropriate situations.

Recommendation No. 1

Develop a system to improve communications between the operating shift organization and management and first line supervisors.

- This could involve more face to face communications and less reliance on electronic information. Face to face communications provides a better forum for exchanging information, explaining the significance of information, questioning, and giving guidance. Safety should be a specific topic covered in these face to face communications.
- CCHS would have included in this recommendation for a reorganization that would have clarified organization responsibility for 50 Unit. Tosco's elimination of the Operations Shift Organization and including the Shift Supervisor in the Production Day Organization satisfies this. Tosco should, if they have not already, clarify lines of communication, responsibility, and authority within this organization.

Recommendation No. 2

Develop a system, or foster a culture or philosophy, that encourages management and first line supervisors to seek to recognize situations that they should exercise their responsibility and authority to proactively ensure that these situations are handled in a safe manner. This could take the form of:

- Questioning the safety aspects of a particular job.
- Issuing written or oral instructions to supplement standard safety procedures.
- Field follow-up on proper execution of the job.
- Proactive communications with the shift operating organization to seek out and respond to operator concerns.

OTHER RECOMMENDATION

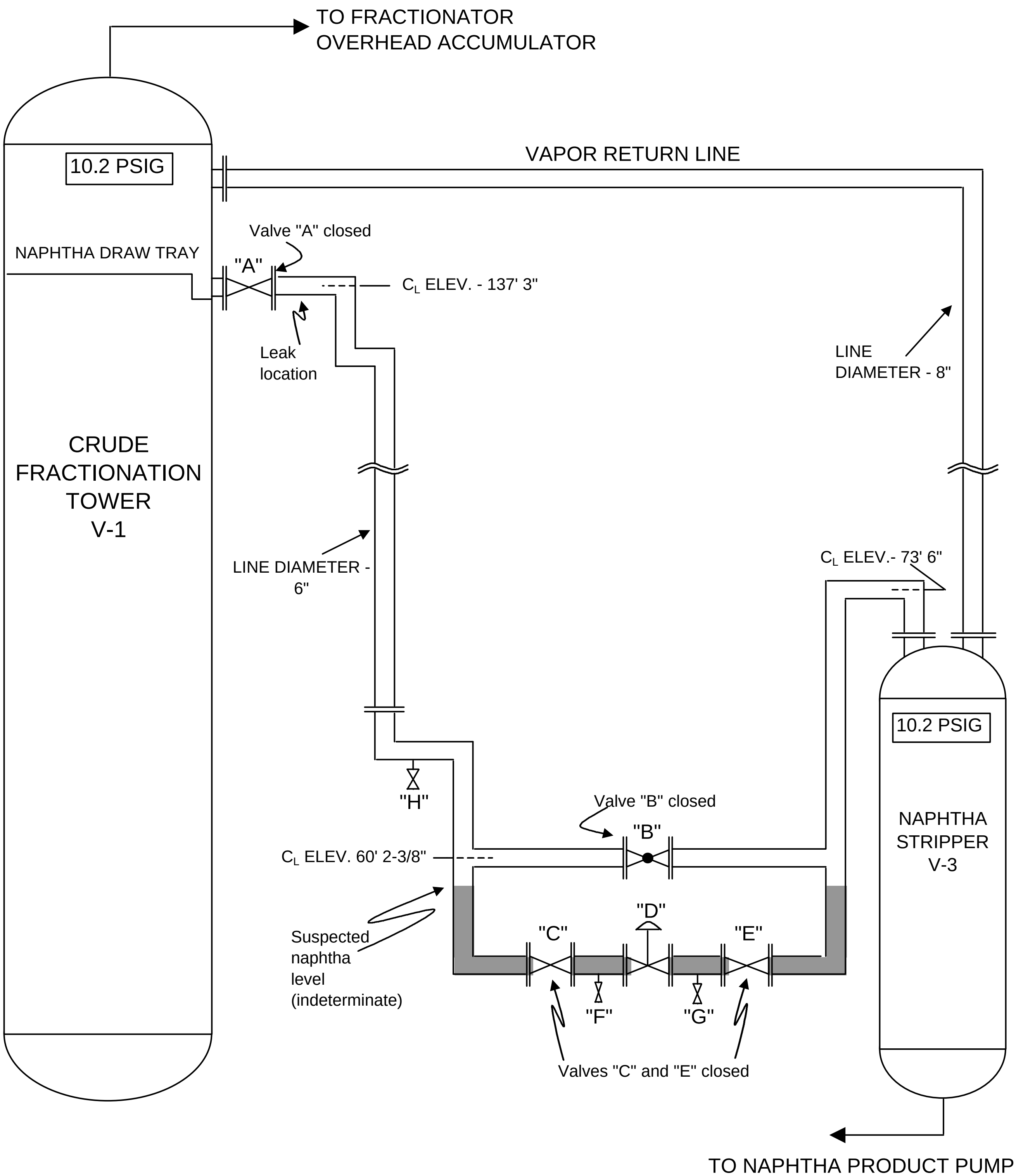
CCHS recommends that Tosco investigate and implement measures to either prevent plugging from occurring at the bottom of the naphtha piping, and/or the means to clean out the piping while 50 Unit is operating. Included in this recommendation would be a means of verifying flow through the level control valve.

APPENDIX A

EXHIBITS

EXHIBIT - 1A

SUSPECTED SITUATION OF NAPHTHA LINE AFTER LEAK ON FEBRUARY 10TH

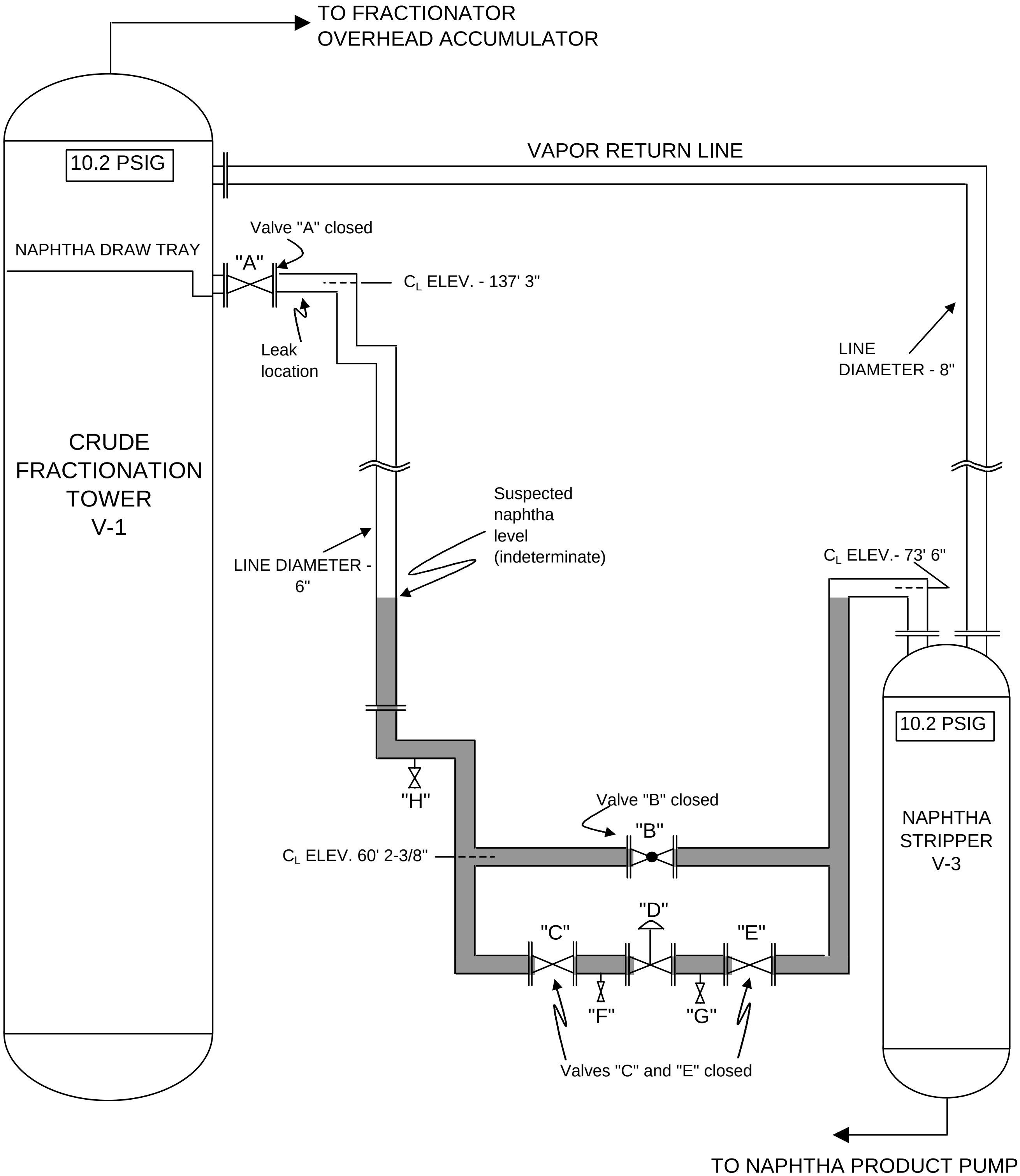


DRAWING NOT TO SCALE

CONTRA COSTA HEALTH SERVICES
July15, 1999

EXHIBIT - 1B

SUSPECTED SITUATION OF NAPHTHA LINE AFTER LEAK ON FEBRUARY 10TH



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CONTRA COSTA HEALTH SERVICES
July15, 1999

EXHIBIT - 1C

SUSPECTED SITUATION OF NAPHTHA LINE AFTER LEAK ON FEBRUARY 10TH

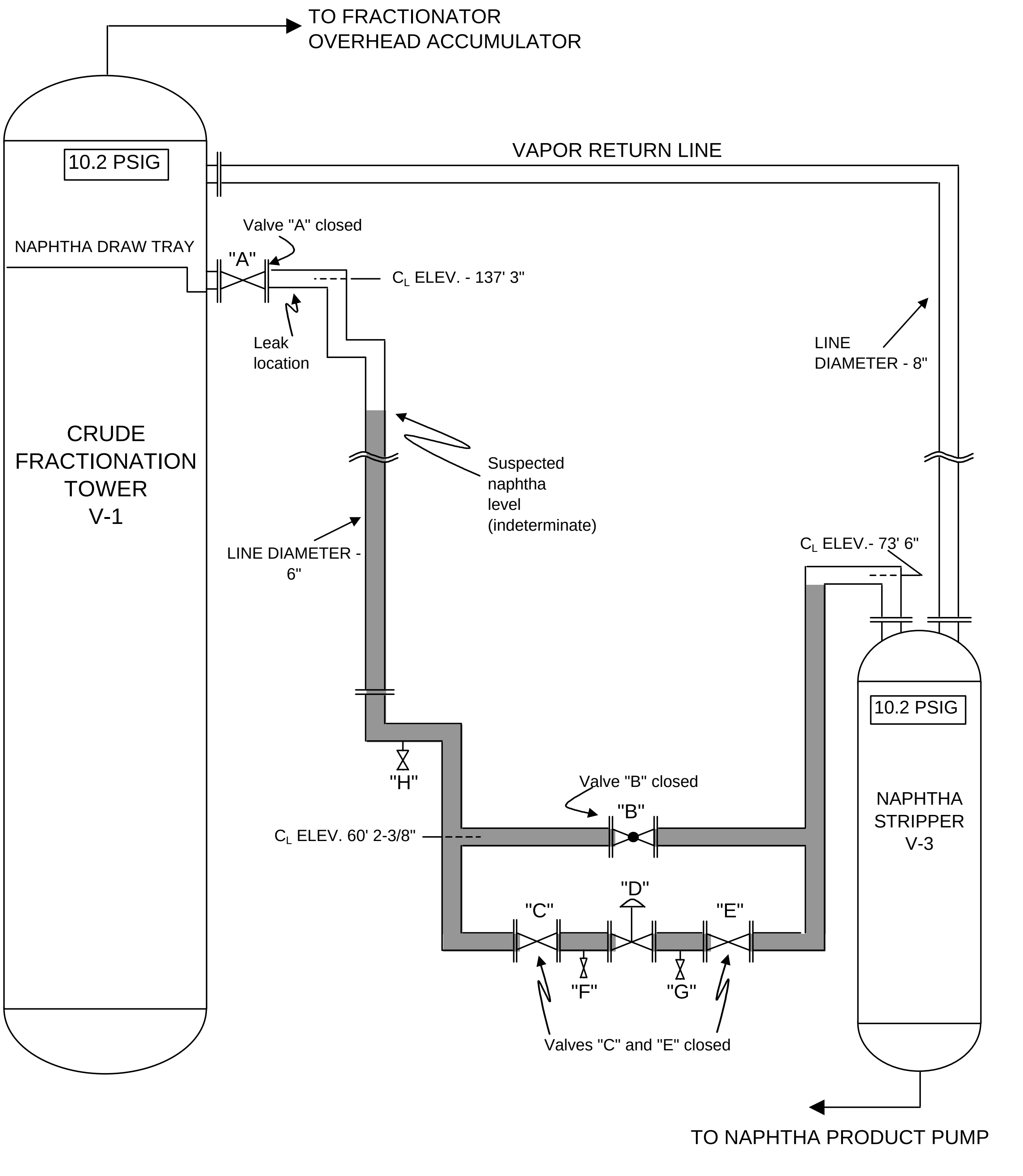

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EXHIBIT - 2

ACTUAL SITUATION OF NAPHTHA LINE AFTER LEAK OF FEBRUARY 10TH

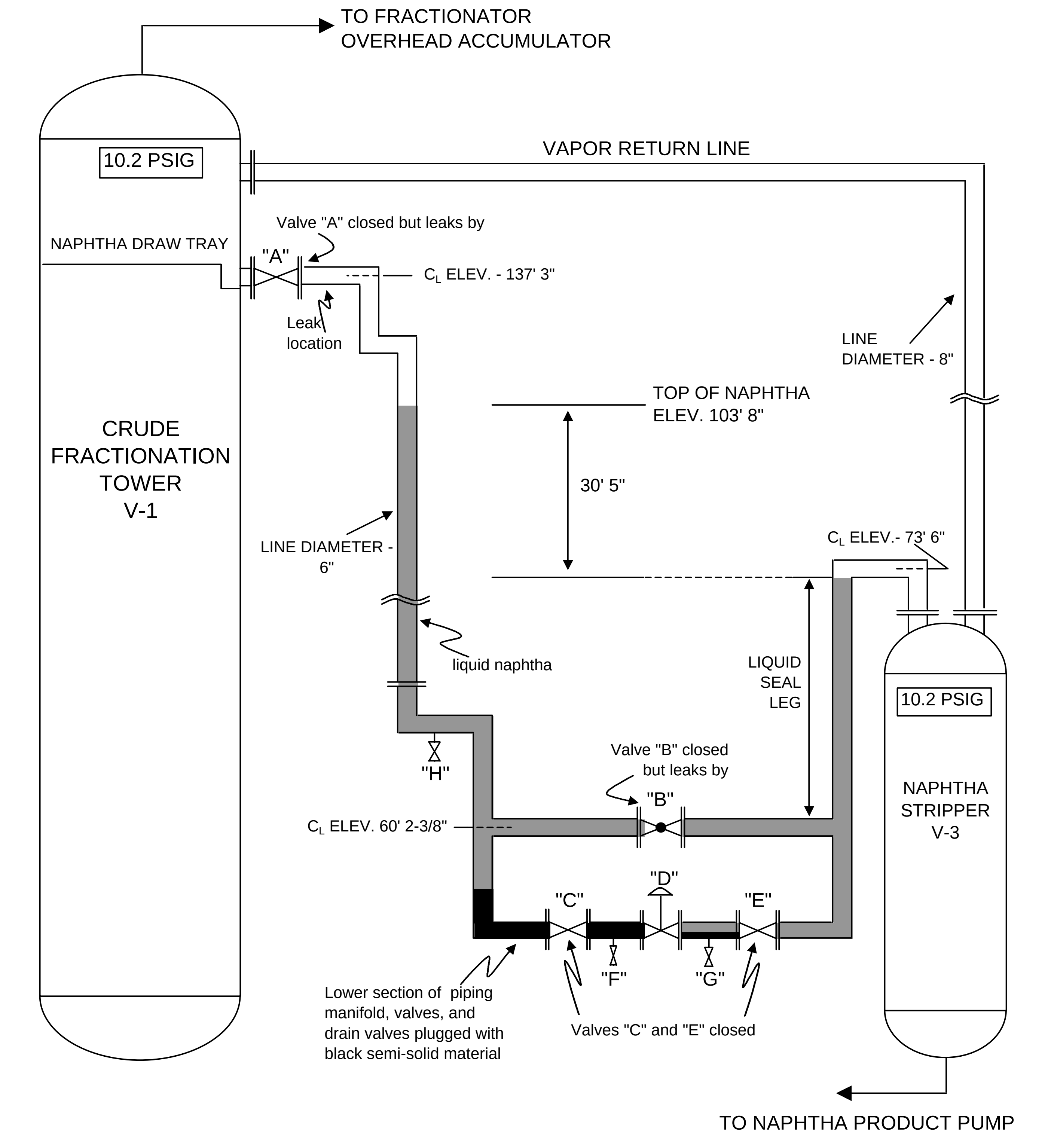

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EXHIBIT - 3

REQUIRED PREPARATION OF NAPHTHA SYSTEM BEFORE COLD CUTTING STARTED ON FEBRUARY 23RD

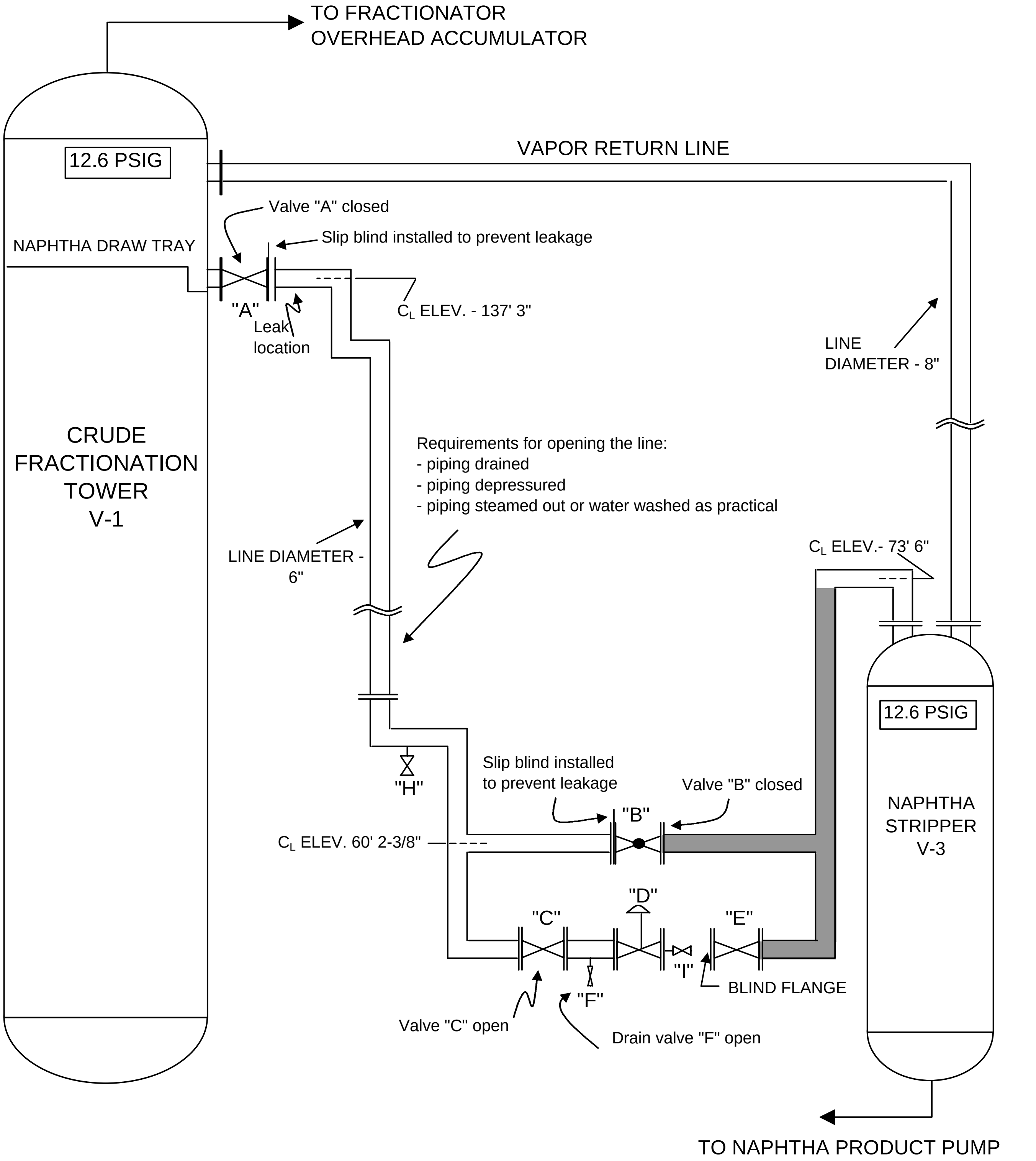

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EXHIBIT - 4

ACTUAL CONDITION OF NAPHTHA SYSTEM BEFORE COLD CUTTING BEGAN ON FEBRUARY 23RD

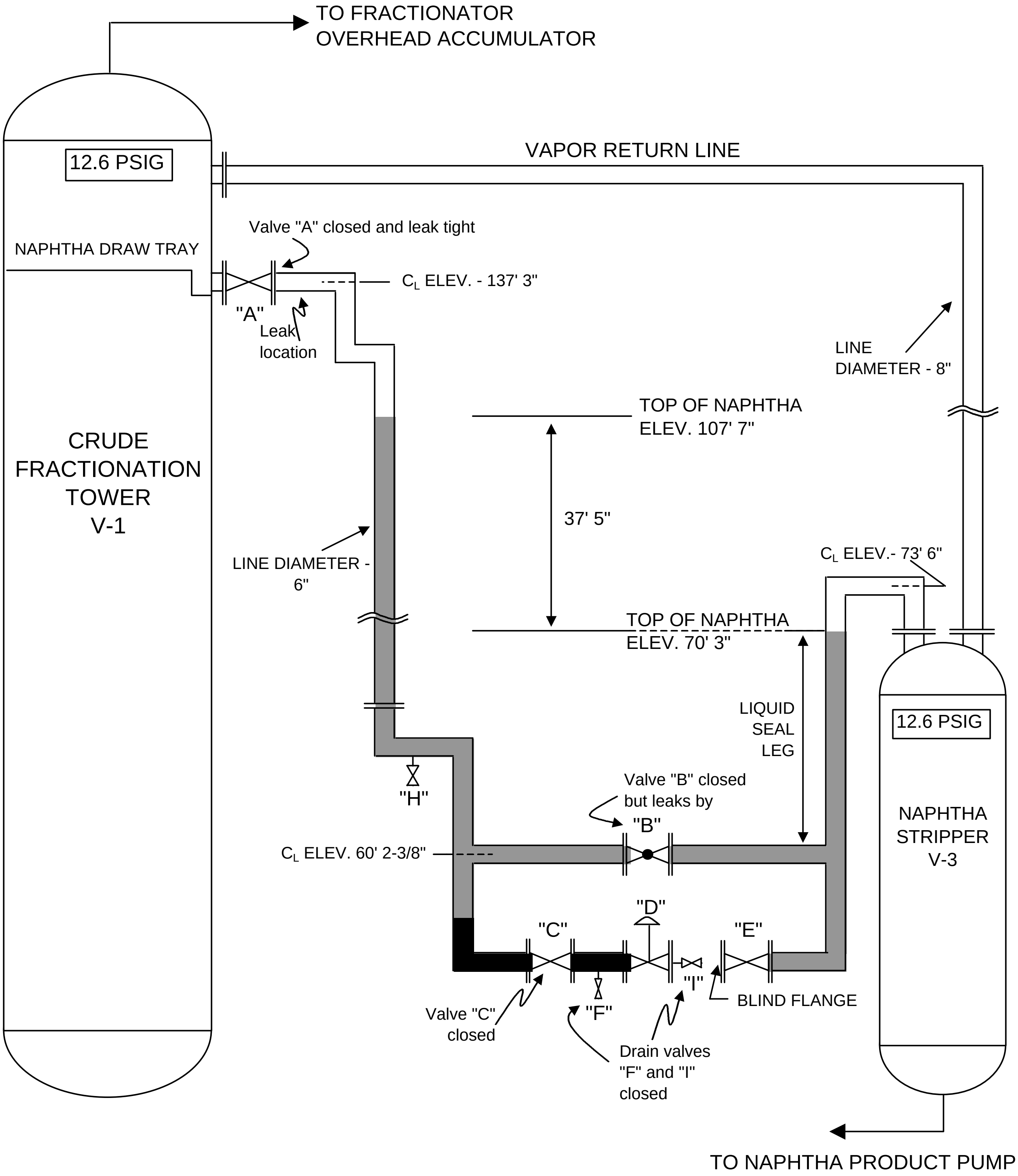

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EXHIBIT - 5

LOCATION OF FIRST AND SECOND COLD CUTS AND NAPHTHA LEVELS BEFORE INITIATION OF DRAINING ATTEMPTS

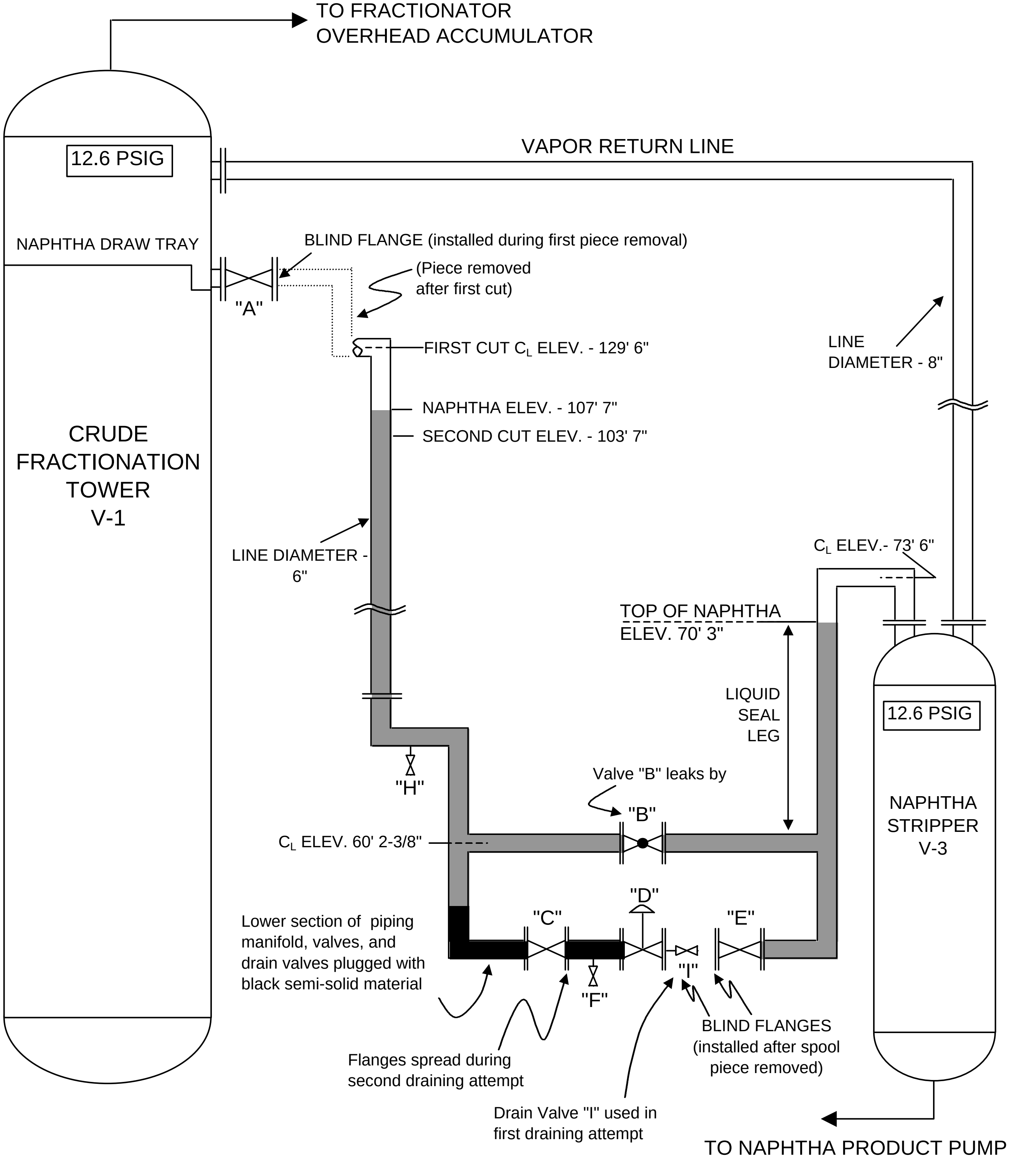

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EXHIBIT - 6

TYPICAL SITUATION WHILE MAKING SECOND COLD CUT AFTER INITIATION OF THIRD DRAINING ATTEMPT

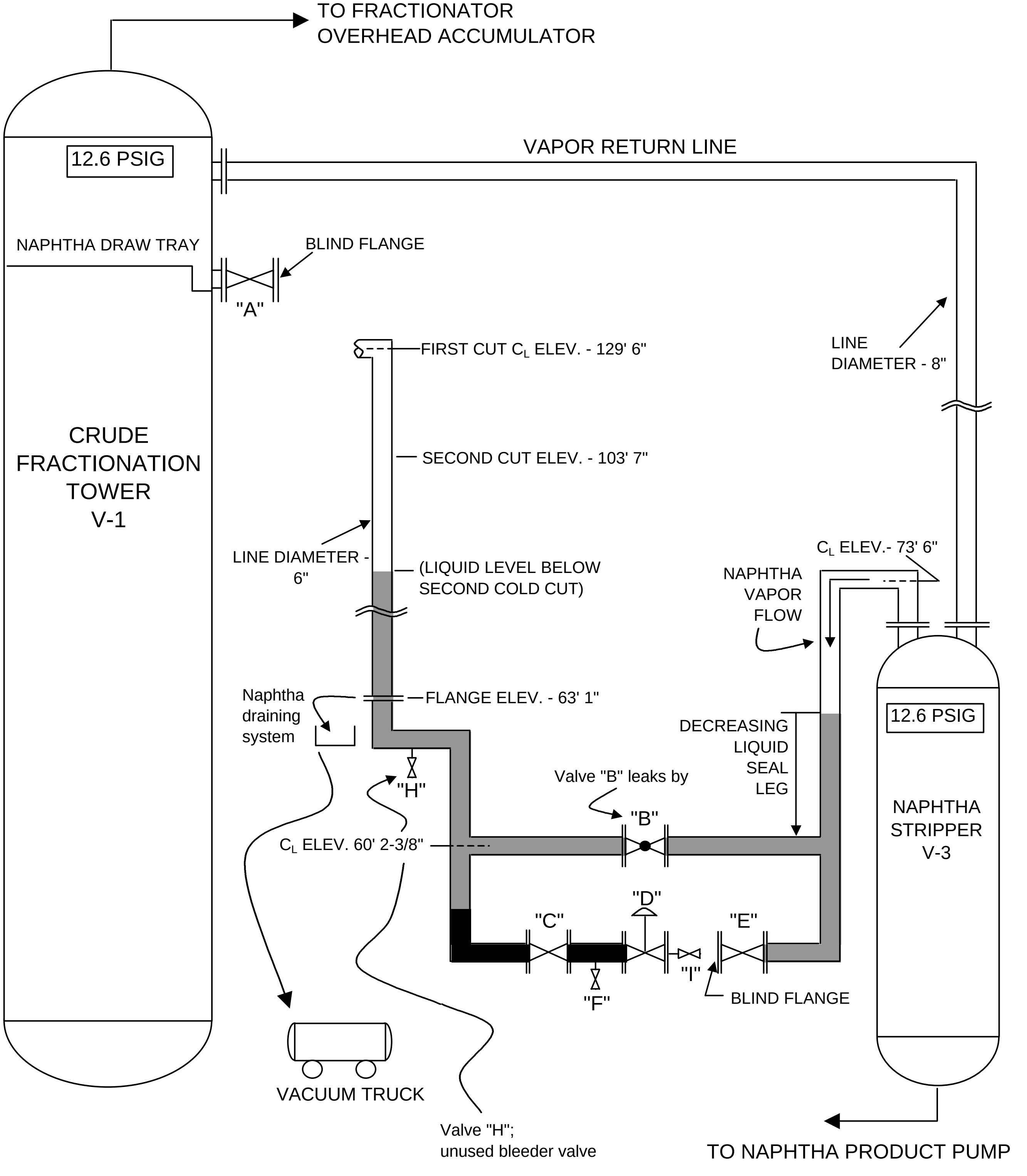

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EXHIBIT - 7
LOSS OF LIQUID SEAL

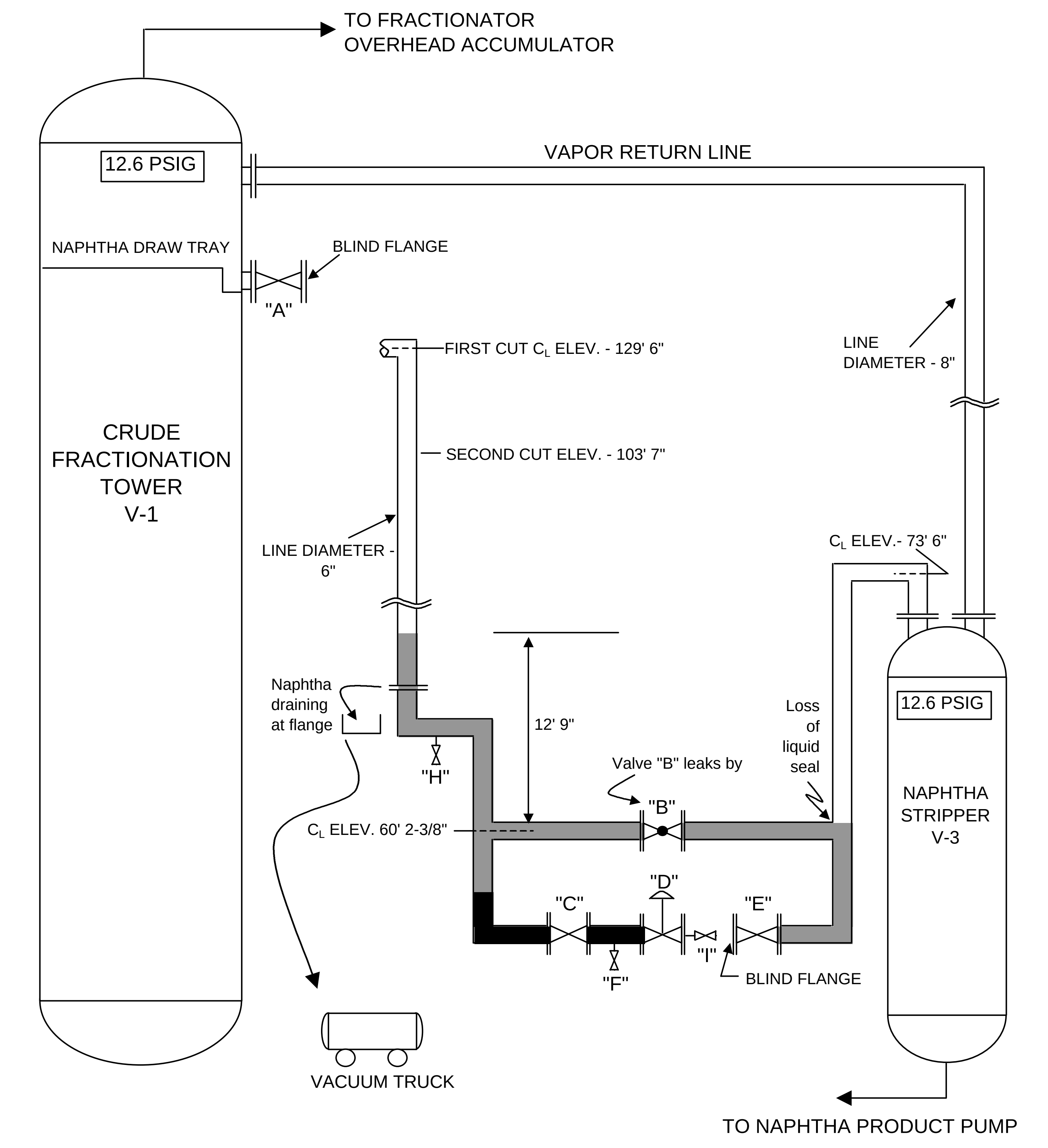

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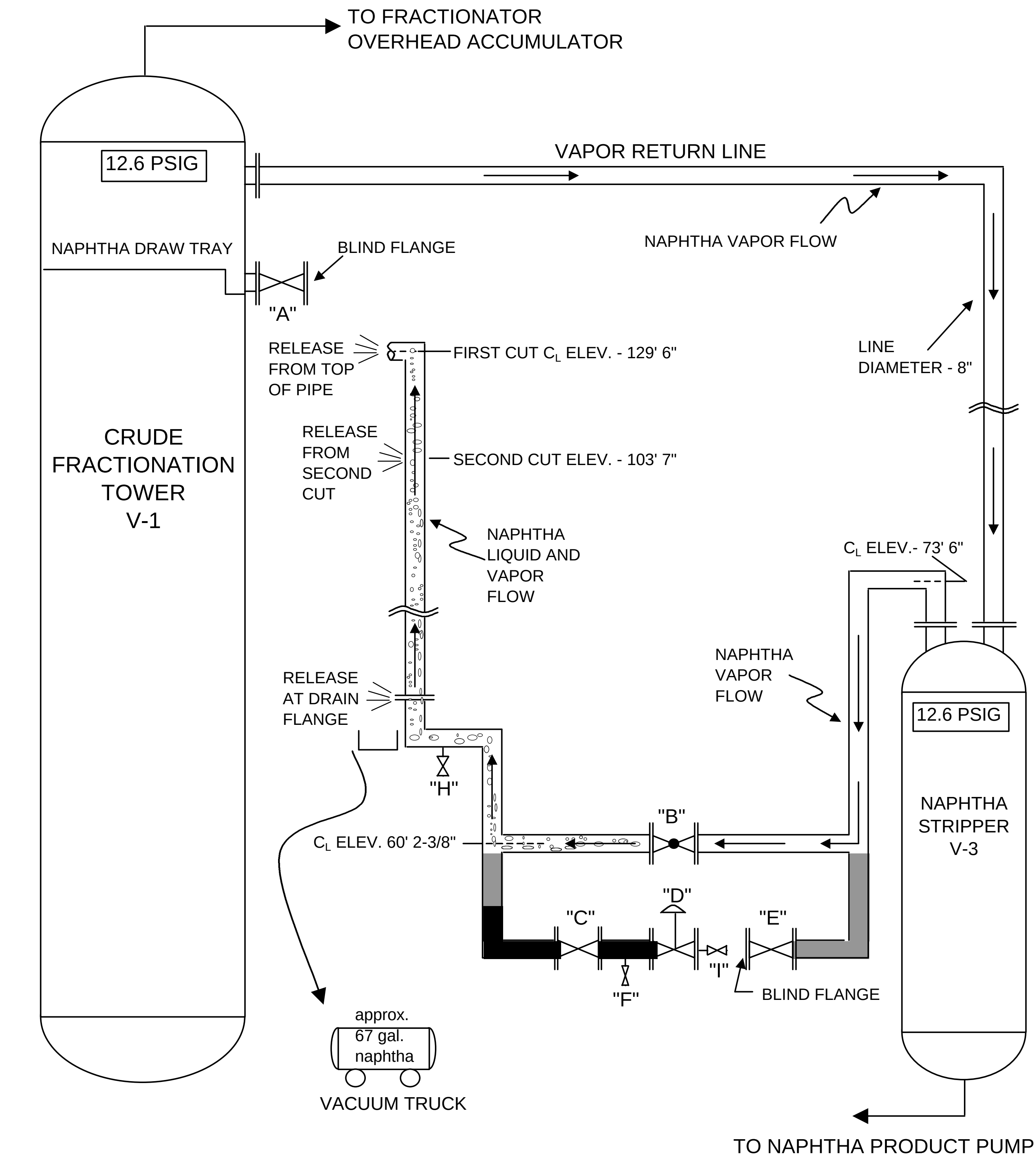
EXHIBIT - 8

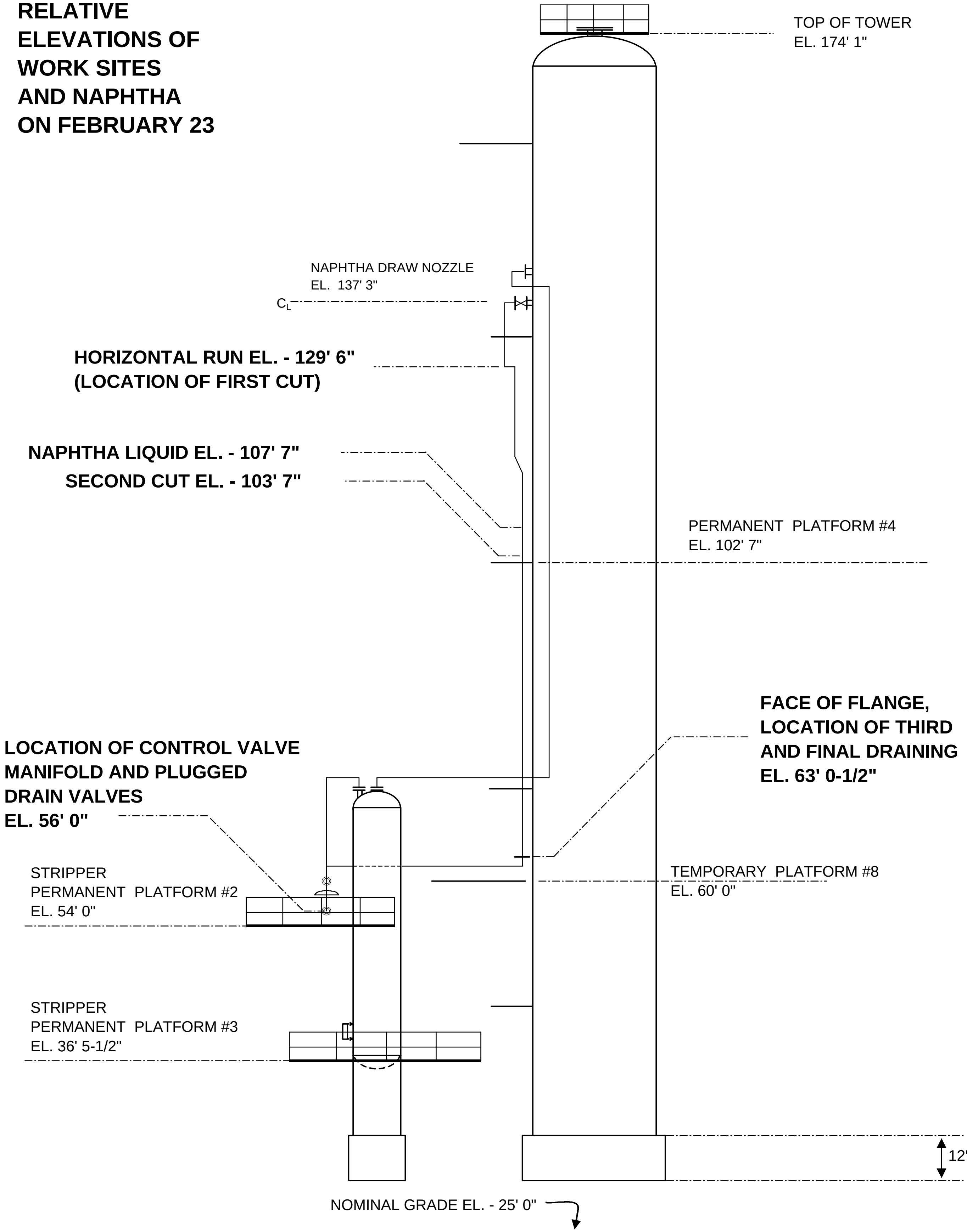
RELEASE OF NAPHTHA RESULTING IN FIRE



DRAWING NOT TO SCALE

CONTRA COSTA HEALTH SERVICES
July 15,1999

EXHIBIT - 9
RELATIVE ELEVATIONS OF WORK SITES AND NAPHTHA ON FEBRUARY 23



APPENDIX B

CORROSION CONTROL AND LABORATORY ANALYSIS

Crude contaminants and their sources

Crude oil is a mixture of hydrocarbon compounds of varying boiling points and densities. A crude fractionation unit is designed to separate these compounds for further processing in downstream units. Along with these hydrocarbon compounds, crude oil contains various organic and inorganic compounds which act as contaminants for downstream operations, and can potentially harm downstream equipment and catalysts.

Examples of these contaminants are as follows:

- organic and inorganic salts
- organic and inorganic acids (sometimes formed by decomposition of salts)
- sulfur-containing compounds
- solids/sediment
- water
- nitrogen

Effects of contaminants on process operation and equipment

Salts and acids in crude oil can cause severe corrosion problems in downstream processes. These salts and acids attack different locations of a process, usually based on process temperatures (i.e., some attack the lower, or hotter, areas of a tower, while some attack the higher, or cooler, areas). The presence of water in the upper areas of a tower (at temperatures below the dew point) also affects corrosion rates. Salts can form highly corrosive sites in the presence of water. At these corrosive sites, water combines with the chlorides from the salts to form highly corrosive hydrochloric acid, which pits, and may eventually hole-through the metal.

Sulfur compounds also can increase corrosion downstream, but are mainly considered as poisons to downstream catalytic reaction units. Sulfur compounds in refining products is a significant problem for certain users.

Solids and sediment in crude cause plugging with the potential for significant operability problems. Metals in crude oil are highly undesirable to certain downstream processes. Metals are concentrated in the heavier crude oil components, and when entering certain reaction units, can cause damage to reactor catalysts.

Water in any process feed, if not removed prior the entering a high-temperature vessel, can cause potentially serious damage to equipment. As the water is rapidly vaporized to steam, the sudden increase in volumes and pressures could result in vessel failure.

Nitrogen is another potential poison to downstream units. Nitrogen can deactivate reactor catalyst, causing significant decrease in operational performance.

There are other potential contaminants in crude oil, each, with similar consequences to those listed above. Different crude slates have varying amounts of the above contaminants, as well as varying concentrations of components with different boiling points. For example, a crude slate from one feed tank could contain significantly higher concentrations of lighter hydrocarbons than that from another tank. When the crude feed is suddenly changed from a heavier feed to a lighter feed, there is a possibility of the lighter components surging up the Fractionation, bringing with it acidic components that normally reside in the bottom of the tower. This can result in an increase in corrosion rates in the upper sections of the Fractionator.

Contaminant removal

Only a few of the contaminants listed above are of concern in a crude fractionation process. They are organic and inorganic salts, organic and inorganic acids, solids/sediment, and water. The primary means for removal of these contaminants is through the desalting process. Poor desalting can result in carryover of contaminants to the crude fractionator and other downstream equipment.

As described if Figure 3-1 in Section 3, Process Description, Desalting is achieved in large horizontal vessels called Desalters, which are located fairly early in the crude refining process. Desalting is often a two-stage process, with additional water injection and mixing before each stage. The crude it is mixed with wash water and desalting chemicals, forming an emulsion, and fed to the Desalters. Desalters are designed to be large enough to allow sufficient residence time for the oil/water emulsion to separate. As the emulsion separates or "breaks", the water phase, containing the majority of the salts and acids, sinks to the bottom of the Desalter. Assisting in the water/oil separation process are electrostatic grids located in the oil layer above the water layer. These grids electrically "attract" small water droplets entrained in the oil phase. As more droplets form together, they become large enough to drop out of the oil layer into the water layer below. The water is pumped away. The level of the emulsion layer (the layer between the oil phase and the water phase) in the Desalter is controlled to prevent water carryover with the crude feed.

Laboratory test results

Laboratory testing concentrated on three areas: the cause of the original leak, analysis of the bypass Valve B, and analysis of the solid residue that was located in the piping around the Level Control Valve D. The naphtha piping, valves, and various solid and liquid samples were sent to an independent laboratory for metallurgical and chemical analysis. Following is a discussion of the test results and conclusions.

The original leak in the bottom of the elbow of the naphtha piping was determined to have occurred due to ammonium chloride corrosion. As ammonium chloride salts deposited on the metal piping walls. These salt deposits combined with condensing water and formed hydrochloric acid, which eventually holed through the carbon steel piping. The liquid samples taken from the control valve manifold were found to have extremely high total acid numbers, as well as other corrosive constituents, indicating increased acid corrosion potential.

The effects of corrosion/erosion on the 4-inch bypass Valve B were also analyzed. The valve body, constructed of carbon steel, experienced corrosion similar to that seen in the upstream piping. Even though the valve disc and seat ring are of harder, more corrosion/erosion resistant metal (13 Chrome steel) than the carbon steel body of the valve, they experienced considerably more corrosion/erosion than the rest of the valve body. This can be attributed directly to the higher velocities of fluid through a partially closed valve. This bypass valve, designed for periodic operation when the control valve is not operating correctly, had been in continuous operation for some time.

Laboratory conclusions state the disc/seat ring lost so much metal due to corrosion/erosion that the seal between them was lost. In a closed position, the disc was in metal-to-metal contact with the seat ring at only two locations. The open area of the gaps was equivalent to a 1½-inch diameter hole when the valve was in the closed position. The erosion occurred because the valve was in a partially open position during normal operation.

The solid residue consisted mainly of iron oxides mixed with sulfur and chloride compounds. These presence of these compounds indicate corrosion upstream. The insolubility of these compounds allowed them to settle in the low points of the piping, causing the plugging of Level Control Valve D. This plugging prevented Valve D from controlling properly, necessitating the continuous use of bypass Valve B.

Tosco Steps to Improve Desalter Operation at 50 Unit

There is evidence that there had been difficulties in the Desalter operation at 50 Unit for quite some time; possibly since the crude slates were changed after the shut down of No. 3 Crude Unit in 1998. After reviewing the Desalter operating history and discussions with Tosco's desalting chemical technical sales representatives, it was discovered that the

Desalters had been frequently operating outside their design parameters. In addition, there were periodic changes in crude slates that frequently resulted in Desalter upsets for extended periods of time (i.e., over multiple shifts).

Based on the Desalter operating history and the discussion above, Tosco has decided to take the following steps to improve the Desalter operation at 50 Unit:

- Establish minimum 6 hour settling time of waterborne crude prior to introduction as feed the 50 Unit.

- Install mixers in crude tanks as the tanks are removed from service for inspection/maintenance work.

- Increase focus on water draining to minimize water heel in feed tanks.

- Install equipment to pump water/emulsion to separate tank for improved water management vs. draining water to sewer.

- Work with treatment chemical vendors to improve treatment performance.

- Evaluate the performance of current process chemical treatment supplier.

- Study desalter technology improvements (e.g., considering a change to bielectric desalting).

APPENDIX C

PIPING ISOLATION METHODS

Most standard piping is connected by flanges. A flange is a flat piece of metal, welded onto the ends of lengths of pipes, with bolt holes which allow for bolting flanged pipe to other flanged lengths of pipe or to other pieces of equipment. Between the two flanges is a gasket, a thin piece of material compatible to whatever service the piping is in, which provides a seal between the metal surfaces of the flanges.

The number of flange bolt holes varies depending on pipe diameter and pressure service. Larger or higher pressure systems have greater numbers of bolt holes. A typical flange in the most common service (as in the naphtha draw piping) normally has eight bolt holes, as shown in the attached figures.

Prior to maintenance on process piping or other equipment attached to process piping, industry regulations require positive isolation of the process whenever possible. Providing positive isolation means that the flow of any material through the pipe is prevented through mechanical means (beyond a single closed valve). Positive isolation provides the maximum protection for workers and equipment from unexpected releases of hazardous material through a pipe.

There are different methods for providing positive isolation of piping. The most secure methods for providing positive isolation are air gapping and slip blinding. An additional method discussed below is the double block and bleed.

Air Gapping

Figure C-1 shows air gapping. A short piece of flanged piping between Flanges A and B was removed, creating the air gap, referring to the empty space between the two blind flanges. A blind flange is then installed on the face of Flanges A and B. A blind flange is a flat piece of metal that is bolted to the open face of a pipe flange. A blind flange is often referred to by other names, including OD and boilermaker.

Slip Blinding

Figure C-2 shows two pipe flanges that have been separated for the installation of a slip blind. To install a slip blind, the top three bolts are removed from the flange, and the remaining five, are loosened. A slip blind, a thin piece of metal with a tongue-like protrusion, is literally “slipped” between the two flanges. A slip blind has no bolt holes, so it rests between the bolts and covers the pipe hole. The two flanges are then re-bolted. Slip blinding is used when the system is to be isolated without removing any piping.

Prior to installing blinds with either of these methods, as with any maintenance that requires opening a piece of pipe or equipment for maintenance, the system must be blocked in, drained, and flushed as thoroughly as possible to minimize the chances of personnel exposure to hazardous materials.

Double Block and Bleed

An additional method of isolation is called “double block and bleed,” as shown in Figure C-3. A double block and bleed consists of two valves with a bleeder valve in between. The two valves are closed and the bleeder valve is open. The bleeder valve must be clean and unplugged. If either of the valves leak by, the bleeder valve will indicate this by allowing the leaking material to flow out through it and prevent leakage past both block valves. When this isolation method is used, the double block and bleed should be kept under surveillance, so the work can be stopped if a leak is discovered. Properly monitored, double blocks and bleeds provide the protection equal to one blind.

PIPING ISOLATION METHODS

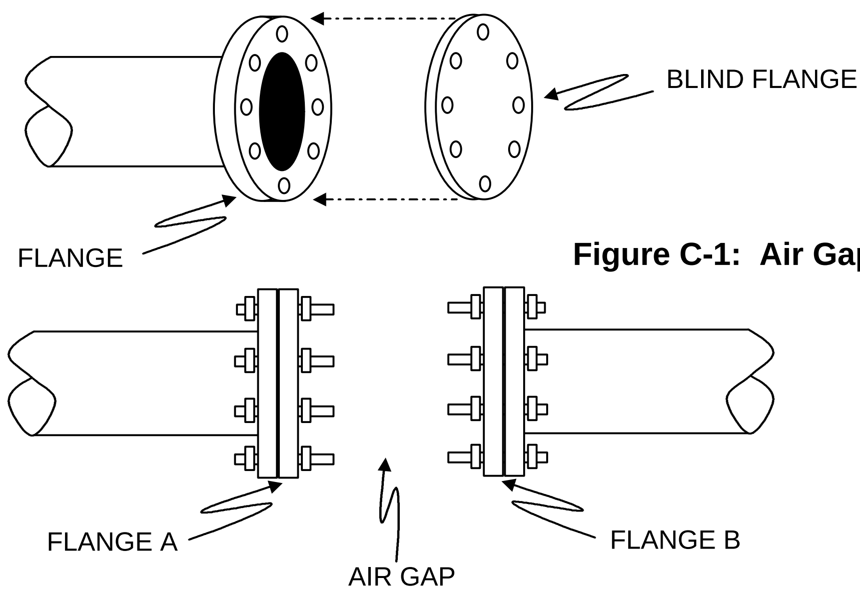


Figure C-1: Air Gapping

Note: Not all bolts are actually removed. Three bolts are removed, five loosened, the slip blind installed, and all bolts are installed and tightened.

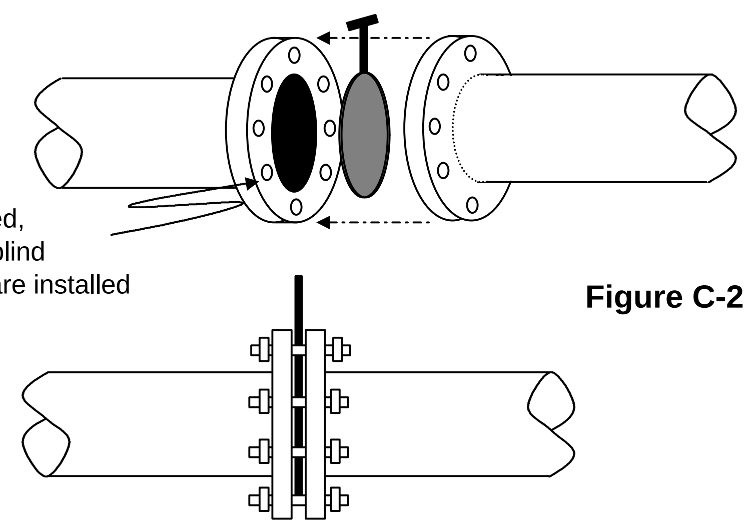


Figure C-2: Slip Blinding

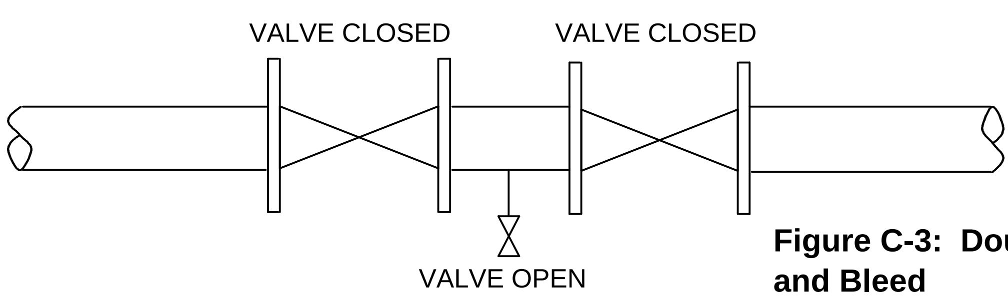


Figure C-3: Double Block and Bleed