U.S. CHEMICAL SAFETY AND HAZARD INVESTIGATION BOARD

INVESTIGATION REPORT

REFINERY EXPLOSION AND FIRE

(15 Killed, 180 Injured)

KEY ISSUES:

SAFETY CULTURE

REGULATORY OVERSIGHT

PROCESS SAFETY METRICS

HUMAN FACTORS

BP

TEXAS CITY, TEXAS

MARCH 23, 2005

REPORT NO. 2005-04-I-TX

MARCH 2007

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Acronyms and Abbreviations

ACC	American Chemistry Council
AIChE	American Institute of Chemical Engineers
API	American Petroleum Institute
ARPD	Amoco Refining Planning Department
ARU	Aromatics Recovery Unit
AU2	Aromatics Unit #2
BOT	Basic Operator Training
BPSH	BP South Houston
bpd	barrels per day
BUL	Business Unit Leader
CAIB	Columbia Accident Investigation Board
CDP	Compliance Delivery Process
CFHU	Cat Feed Hydrotreating Unit
CCPS	Center for Chemical Process Safety
CMMS	Computerized Maintenance Management Software
CSB	U.S. Chemical Safety and Hazard Investigation Board
CVP	Capital Value Process
DIERS	Design Institute for Emergency Relief Systems
DIH	Deisohexanizer
EHS	Environment, Health and Safety
EPA	Environmental Protection Agency
GHSER	Getting Health, Safety, and Environment Right
gph	gallons per hour

HAZOP	Hazard and Operability Study
HC1	Hydrogen Chloride
HRO	High Reliability Organization
HSE	Health, Safety & Environment
HSSE	Health, Safety, Security, & Environment
HUF	Heavy Ultraformate Fractionator
IH	Industrial Hygiene
IMAS	Industrial Mutual Aid System
ISBL	Inside Battery Limits
ISOM	Isomerization unit
kPa	kilopascal
KPI	Key Performance Indicators
L&D	Learning and Development
MAR	Major Accident Risk
MAWP	Maximum Allowable Working Pressure
MDL	Manufacturing Delivery Leader
MOA	Memorandum of Agreement
MOC	Management of Change
mscf	million standard cubic feet
NDU	Naptha Desulfurization Unit
NESHAP	National Emissions Standard for Hazardous Air Pollutants
NPRA	National Petrochemical and Refiners Association
NPS	Nominal Pipe Size
NTSB	National Transportation Safety Board
OSBL	Outside Battery Limits

OCAM	Operator Competency Assurance Model
OSHA	Occupational Safety and Health Administration
P&ID	Piping and Instrumentation Diagram
PHA	Process Hazard Analysis
PIP	Piping Integrity Program
pph	pounds per hour
PPS	Amoco Petroleum Products Sector
psi	pounds per square inch
PSM	Process Safety Management
PSS	Process Safety Standard
PSSR	Pre-Startup Safety Review
PT	Process Technician
QA/QC	Quality Assurance/Quality Control
R&M	Refining and Marketing
RCFA	Root Cause Failure Analysis
RHU	Resid Hydrotreating Unit
RIF	Recordable Injury Frequency
RMP	Risk Management Program
SAP	Systems Applications and Products
SEP	Special Emphasis Program
SHIFT	South Houston Infrastructure for Tomorrow
SIS	Safety Instrumented System
SOI	Standard Operating Instructions
SOPs	Standard Operating Procedures
SPU	Strategic Performance Unit

TCEQ	Texas Commission on Environmental Quality
TCR	Texas City Refinery
TCS	Texas City Site
TSP	Traffic Safety Policy
UK	United Kingdom
ULC	Ultracracker unit
UOP	Universal Oil Products
USW	United Steelworkers
UU3	Ultraformer Unit # 3
UU4	Ultraformer Unit #4
VOC	Volatile Organic Compounds
VPP	Variable Pay Plan

1.0 EXECUTIVE SUMMARY

1.1 Incident synopsis

On March 23, 2005, at 1:20 p.m., the BP Texas City Refinery suffered one of the worst industrial disasters in recent U.S. history. Explosions and fires killed 15 people and injured another 180, alarmed the community, and resulted in financial losses exceeding $1.5 billion. The incident occurred during the startup of an isomerization[1] (ISOM) unit when a raffinate splitter tower[2] was overfilled; pressure relief devices opened, resulting in a flammable liquid geyser from a blowdown stack that was not equipped with a flare. The release of flammables led to an explosion and fire. All of the fatalities occurred in or near office trailers located close to the blowdown drum. A shelter-in-place order was issued that required 43,000 people to remain indoors. Houses were damaged as far away as three-quarters of a mile from the refinery.

The BP Texas City facility is the third-largest oil refinery in the United States. Prior to 1999, Amoco owned the refinery. BP merged with Amoco in 1999 and BP subsequently took over operation of the plant.

1.2 Scope of Investigation

Due to the significance of the disaster, the U.S. Chemical Safety and Hazard Investigation Board (CSB) investigated not only BP'S safety performance at Texas City, but also the role played by BP Group

[1] The refining isomerization process converts straight chain normal pentane and normal hexane streams to the higher octane branched hydrocarbons isopentane and isohexane that are used for gasoline blending.

[2] The raffinate splitter is a distillation tower that takes raffinate, a non-aromatic, primarily straight-chain hydrocarbon mixture and separates it into light and heavy components.

management, based in London, England.[3] The CSB further examined the effectiveness of the Occupational Safety and Health Administration (OSHA), which has primary U.S. federal government oversight responsibility for worker safety.

1.2.1 BP Group and Texas City

The Texas City disaster was caused by organizational and safety deficiencies at all levels of the BP Corporation. Warning signs of a possible disaster were present for several years, but company officials did not intervene effectively to prevent it. The extent of the serious safety culture deficiencies was further revealed when the refinery experienced two additional serious incidents just a few months after the March 2005 disaster. In one, a pipe failure caused a reported $30 million in damage; the other resulted in a $2 million property loss. In each incident, community shelter-in-place orders were issued.

This investigation was conducted in a manner similar to that used by the Columbia Accident Investigation Board (CAIB) in its probe of the loss of the space shuttle. Using the CAIB model, the CSB examined both the technical and organizational causes of the incident at Texas City.

The CAIB report stated that NASA's organizational culture and structure had as much to do with this accident as did the immediate cause.[4]

[3] BP Group management is the global corporate management responsible for business operations, including refining and marking (R&M).

[4] Immediate causes are the events or conditions that lead directly or indirectly to an incident, such as mechanical failure or human error (CCPS, 1992a). The immediate cause of the Columbia space shuttle disaster was striking of the left shuttle wing by a piece of insulating foam that separated from the external tank about a minute after launch. During re-entry, superheated air melted the area damaged by the foam strike, weakening the structure, leading to the subsequent failure of the structure and break up of the shuttle (CAIB report, 2003, vol. 1, p.9).

The CAIB also observed that:

> Many accident investigations make the same mistake in defining causes. They identify the widget that broke or malfunctioned, then locate the person most closely connected with the technical failure: the engineer who miscalculated an analysis, the operator who missed signals or pulled the wrong switches, the supervisor who failed to listen, or the manager who made bad decisions. When causal chains are limited to technical flaws and individual failures, the ensuing responses aimed at preventing a similar event in the future are equally limited: they aim to fix the technical problem and replace or retrain the individual responsible. Such corrections lead to a misguided and potentially disastrous belief that the underlying problem has been solved (CAIB, 2003).

Simply targeting the mistakes of BP's operators and supervisors misses the underlying and significant cultural, human factors,[5] and organizational causes of the disaster that have a greater preventative impact.[6] One underlying cause was that BP used inadequate methods to measure safety conditions at Texas City. For instance, a very low personal injury rate at Texas City gave BP a misleading indicator of process safety performance. In addition, while most attention was focused on the injury rate, the overall safety culture and process safety management (PSM)[7] program had serious deficiencies. Despite numerous previous fatalities at the Texas City refinery (23 deaths in the 30 years prior to the 2005

[5] "Human factors refer to environmental, organizational, and job factors, and human and individual characteristics, influence behaviour at work in a way which can affect health and safety" (HSE, 1999).

[6] The Center for Chemical Process Safety (CCPS) states that identifying the underlying or root causes of an incident has a greater preventative impact by addressing safety system deficiencies and averting the occurrence of numerous other similar incidents, while addressing the immediate cause only prevents the identical accident from reoccurring (CCPS,1992a).

[7] CCPS defines process safety as a "discipline that focuses on the prevention of fires, explosions and accidental chemical releases at chemical process facilities." Process Safety Management (PSM) applies management principles and analytical tools to prevent major accidents rather than focusing on worker occupational health and safety issues, such as fall protection and personal protective equipment (CCPS, 1992a).

disaster) and many hazardous material releases, BP did not take effective steps to stem the growing risk of a catastrophic event.

Cost-cutting and failure to invest in the 1990s by Amoco and then BP left the Texas City refinery vulnerable to a catastrophe. BP targeted budget cuts of 25 percent in 1999 and another 25 percent in 2005, even though much of the refinery's infrastructure and process equipment were in disrepair. Also, operator training and staffing were downsized.

1.2.2 OSHA

OSHA enforcement at the BP Texas City refinery was also examined. In the years prior to the incident OSHA conducted several inspections, primarily in respose to fatalities at the refinery, but did not identify the likelihood for a catastrophic incident, nor did OSHA prioritize planned inspections of the refinery to enforce process safety regulations, despite warning signs. After this incident OSHA uncovered 301 egregious willful[8] violations for which BP paid a $21 million fine, the largest ever issued by OSHA in its 35-year history. Prior to OSHA issuing citations, the refinery had two additional serious incidents. Despite the large number of major violations on the ISOM unit, and these two additional serious incidents in 2005, OSHA did not conduct a comprehensive inspection of any of the other 29 process units at the Texas City refinery.[9]

[8] A "willful" violation is defined as an "act done voluntarily with either an intentional disregard of, or plain indifference to, the Act's requirements." Conie Construction, Inc. v. Reich, 73 F.3d 382, 384 (D.C. Cir. 1995). An "egregious" violation, also know as a "violation-by-violation" penalty procedure, is one where penalties are applied to each instance of a violation without grouping or combining them.

[9] The settlement agreement between OSHA and BP from the ISOM incident and other investigations did require BP to retain a PSM expert to conduct comprehensive audits at the Texas City refinery to assess the "robustness of the PSM systems." United States of America Occupational Safety and Health Administration, BP Products North America Inc. Settlement Agreement, September 21, 2005.

OSHA's national focus on inspecting facilities with high personnel injury rates, while important, has resulted in reduced attention to preventing less frequent, but catastrophic, process safety incidents such as the one at Texas City. OSHA's capability to inspect highly hazardous facilities and to enforce process safety regulations is insufficient; very few comprehensive process safety inspections were conducted prior the ISOM incident and only a limited number of OSHA inspectors have the specialized training and experience needed to perform these complex examinations.

1.3 Incident Description

On the morning of March 23, 2005, the raffinate splitter tower in the refinery's ISOM unit was restarted after a maintenance outage. During the startup, operations personnel pumped flammable liquid hydrocarbons into the tower for over three hours without any liquid being removed, which was contrary to startup procedure instructions. Critical alarms and control instrumentation provided false indications that failed to alert the operators of the high level in the tower. Consequently, unknown to the operations crew, the 170-foot (52-m) tall tower was overfilled and liquid overflowed into the overhead pipe at the top of the tower.

The overhead pipe ran down the side of the tower to pressure relief valves located 148 feet (45 m) below. As the pipe filled with liquid, the pressure at the bottom rose rapidly from about 21 pounds per square inch (psi) to about 64 psi. The three pressure relief valves opened for six minutes, discharging a large quantity of flammable liquid to a blowdown drum with a vent stack open to the atmosphere. The blowdown drum and stack overfilled with flammable liquid, which led to a geyser-like release out the 113-foot (34 m) tall stack. This blowdown system was an antiquated and unsafe design; it was originally installed in the 1950s, and had never been connected to a flare system to safely contain liquids and combust flammable vapors released from the process.

The released volatile liquid evaporated as it fell to the ground and formed a flammable vapor cloud. The most likely source of ignition for the vapor cloud was backfire from an idling diesel pickup truck located about 25 feet (7.6 m) from the blowdown drum. The 15 employees killed in the explosion were contractors working in and around temporary trailers that had been previously sited by BP as close as 121 feet (37 m) from the blowdown drum.

1.4 Conduct of the Investigation

Investigators from the CSB arrived at the facility on the morning of March 24, 2005. During the investigation, the CSB reviewed over 30,000 documents; conducted 370 interviews; tested instruments; and assessed damage to equipment and structures in the refinery and surrounding community. Electronic data from the computerized control system and process information from five years of previous startups were also examined. The CSB investigation team was supplemented by experts in blast damage assessment, vapor cloud modeling, pressure relief system design, distillation process dynamics, instrument control and reliability, and human factors.

Several analytical tools were used by CSB in its investigation of the BP incident, including timeline construction and logic tree causal analysis. See Section 2.3 for an incident timeline, Appendix A for an organizational timeline leading up to the incident, and Appendix B for the logic tree.

This investigation was coordinated with OSHA; the U.S. Environmental Protection Agency (EPA); the Texas Commission of Environmental Quality (TCEQ); and BP's investigation team.

1.5 Key Technical Findings

1. The ISOM startup procedure required that the level control valve on the raffinate splitter tower be used to send liquid from the tower to storage. However, this valve was closed by an operator and

the tower was filled for over three hours without any liquid being removed. This led to flooding of the tower and high pressure, which activated relief valves that discharged flammable liquid to the blowdown system. Underlying factors involved in overfilling the tower included:

- The tower level indicator showed that the tower level was declining when it was actually overfilling. The redundant high level alarm did not activate, and the tower was not equipped with any other level indications or automatic safety devices.
- The control board display did not provide adequate information on the imbalance of flows in and out of the tower to alert the operators to the dangerously high level.
- A lack of supervisory oversight and technically trained personnel during the startup, an especially hazardous period, was an omission contrary to BP safety guidelines. An extra board operator was not assigned to assist, despite a staffing assessment that recommended an additional board operator for all ISOM startups.
- Supervisors and operators poorly communicated critical information regarding the startup during the shift turnover; BP did not have a shift turnover communication requirement for its operations staff.
- ISOM operators were likely fatigued from working 12-hour shifts for 29 or more consecutive days.
- The operator training program was inadequate. The central training department staff had been reduced from 28 to eight, and simulators were unavailable for operators to practice handling abnormal situations, including infrequent and high hazard operations such as startups and unit upsets.
- Outdated and ineffective procedures did not address recurring operational problems

during startup, leading operators to believe that procedures could be altered or did not have to be followed during the startup process.

2. The process unit was started despite previously reported malfunctions of the tower level indicator, level sight glass, and a pressure control valve.

3. The size of the blowdown drum was insufficient to contain the liquid sent to it by the pressure relief valves. The blowdown drum overfilled and the stack vented flammable liquid to the atmosphere, which fell to the ground and formed a vapor cloud that ignited. A relief valve system safety study had not been completed.

4. Neither Amoco nor BP replaced blowdown drums and atmospheric stacks, even though a series of incidents warned that this equipment was unsafe. In 1992, OSHA cited a similar blowdown drum and stack as unsafe, but the citation was withdrawn as part of a settlement agreement and therefore the drum was not connected to a flare as recommended.[10] Amoco, and later BP, had safety standards requiring that blowdown stacks be replaced with equipment such as a flare when major modifications were made. In 1997, a major modification replaced the ISOM blowdown drum and stack with similar equipment, but Amoco did not connect it to a flare. In 2002, BP engineers proposed connecting the ISOM blowdown system to a flare, but a less expensive option was chosen.

[10] A flare system is process plant disposal equipment designed to receive and combust waste gases from emergency relief valve discharge or process vent. In an oil refinery, flares convert flammable vapors to less hazardous materials. Flare system equipment includes a vessel, or “knockout drum,” that is sized appropriately to safely contain any liquid discharge. After the liquid is removed, the remaining gases are safely combusted by a flare burner. OSHA withdrew the citation after Amoco argued that the design of the atmospheric blowdown stack was consistent with industry standards.

5. Occupied trailers were sited too close to a process unit handling highly hazardous materials. All fatalities occurred in or around the trailers.

6. In the years prior to the incident, eight serious releases of flammable material from the ISOM blowdown stack had occurred, and most ISOM startups experienced high liquid levels in the splitter tower. Neither Amoco nor BP investigated these events.

7. BP Texas City managers did not effectively implement their pre-startup safety review policy to ensure that nonessential personnel were removed from areas in and around process units during startups, an especially hazardous time in operations.

1.6 Key Organizational Findings

1. Cost-cutting, failure to invest and production pressures from BP Group executive managers impaired process safety performance at Texas City.
2. The BP Board of Directors did not provide effective oversight of BP's safety culture and major accident prevention programs. The Board did not have a member responsible for assessing and verifying the performance of BP's major accident hazard prevention programs.
3. Reliance on the low personal injury rate[11] at Texas City as a safety indicator failed to provide a true picture of process safety performance and the health of the safety culture.
4. Deficiencies in BP's mechanical integrity program resulted in the "run to failure" of process equipment at Texas City.

[11] OSHA's Recordable Occupational Injury and Illness Incidence Rate, which does not include fatalities, is normalized to allow for comparisons across workplaces and industries. The rate is calculated as the number of recordable incidents for each 100 full-time employees per year, based on 2,000 hours worked per employee per year. BP's calculation of injury rate was the same as OSHA's, but included fatalities, and counted fatalities the same as injuries.

5. A “check the box” mentality was prevalent at Texas City, where personnel completed paperwork and checked off on safety policy and procedural requirements even when those requirements had not been met.
6. BP Texas City lacked a reporting and learning culture. Personnel were not encouraged to report safety problems and some feared retaliation for doing so. The lessons from incidents and near-misses, therefore, were generally not captured or acted upon. Important relevant safety lessons from a British government investigation of incidents at BP’s Grangemouth, Scotland, refinery were also not incorporated at Texas City.
7. Safety campaigns, goals, and rewards focused on improving personal safety metrics and worker behaviors rather than on process safety and management safety systems. While compliance with many safety policies and procedures was deficient at all levels of the refinery, Texas City managers did not lead by example regarding safety.
8. Numerous surveys, studies, and audits identified deep-seated safety problems at Texas City, but the response of BP managers at all levels was typically “too little, too late.”
9. BP Texas City did not effectively assess changes involving people, policies, or the organization that could impact process safety.

1.7 Recommendations

1.7.1 New Recommendations

As a result of this investigation, the CSB makes recommendations to the following recipients:

- BP Group Executive Board of Directors
- BP Texas City Refinery
- U. S. Occupational Safety and Health Administration (OSHA)

- American Petroleum Institute (API)
- United Steelworkers International Union and Steelworkers Local 13-1
- Center for Chemical Process Safety (CCPS)

Section 13 of this report provides the detailed recommendations.

1.7.2 Previously Issued Recommendations

The CSB issued recommendations during the course of the investigation. This section provides a brief description; Appendix C provides the full text of each.

1.7.2.1 Safety Culture Recommendation

On August 17, 2005, the CSB issued an urgent safety recommendation to the BP Group Executive Board of Directors that it convene an independent panel of experts to examine BP's corporate safety management systems, safety culture, and oversight of the North American refineries. BP accepted the recommendation and commissioned the BP U.S. Refineries Independent Safety Review Panel, chaired by former Secretary of State James Baker, III ("Baker Panel"). The scope of the Baker Panel's work did not include determining the root causes of the Texas City ISOM incident.

"The Report of the BP U.S. Refineries Independent Safety Review Panel" was issued January 16, 2007. The Baker Panel Report found that "significant process safety issues exist at all five U.S. refineries, not just Texas City," and that BP had not instilled "a common unifying process safety culture among its U.S. refineries." The report found "instances of a lack of operating discipline, toleration of serious deviations from safe operating practices, and [that an] apparent complacency toward serious process safety risk existed at each refinery." The Panel concluded that "material deficiencies in process safety performance exist at BP's five U.S. refineries."

The Baker Panel Report stated that BP's corporate safety management system "does not effectively measure and monitor process safety performance" for its U.S. refineries. The report also found that BP's over-reliance on personal injury rates impaired its perception of process safety risks, and that BP's Board of Directors "has not ensured, as a best practice, that BP's management has implemented an integrated, comprehensive, and effective process safety management system for BP's five US refineries." The report's 10 recommendations to BP addressed providing effective process safety leadership, developing process safety knowledge and expertise, strengthening management accountability, developing leading and lagging process safety performance indicators, and monitoring by the Board of Directors the implementation of the Baker Panel's recommendations.

1.7.2.2 Trailer Siting Recommendations

On October 25, 2005, the CSB issued two urgent safety recommendations. The first called on the American Petroleum Institute (API) to develop new guidelines to ensure that occupied trailers and similar temporary structures are placed safely away from hazardous areas of process plants; API agreed to develop new guidelines. A second recommendation to API and the National Petrochemical and Refiners Association (NPRA) called for both to issue a safety alert urging their members to take prompt action to ensure that trailers are safely located. API and NPRA published information on the two recommendations, referring to the CSB's call for industry to take prompt action to ensure the safe placement of occupied trailers away from hazardous areas of process plants.

1.7.2.3 Blowdown Drum and Stack Recommendations

On October 31, 2006, the CSB issued two recommendations regarding the use of blowdown drums and stacks that handle flammables. The CSB recommended that API revise "Recommended Practice 521, Guide for Pressure Relieving and Depressuring Systems," to identify the hazards of this equipment, to address the need to adequately size disposal drums, and to urge the use of inherently safer alternatives such as flare systems.

The CSB issued a recommendation to OSHA to conduct a national emphasis program for oil refineries focused on the hazards of blowdown drums and stacks that release flammables to the atmosphere and on inadequately sized disposal drums. The CSB further recommended that states that administer their own OSHA plan implement comparable emphasis programs within their jurisdictions.

1.7.2.4 Additional Recommendations from July 28, 2005, Incident

The CSB also made two recommendations as a result of its investigation of the July 28, 2005, incident in the Resid Hydrotreating Unit (RHU) of the BP Texas City refinery, one of two incidents after the March 23, 2005, incident.[12] The RHU had a major fire that resulted in a shelter-in-place for 43,000 people and a reported $30 million in plant property damage. In October 2006, the CSB released a Safety Bulletin on the findings of its investigation of the incident, available at www.csb.gov.

1.8 Organization of the Report

Section 2 describes the events in the ISOM startup that led to the explosion and fires. Section 3 analyzes the safety system deficiencies and human factors issues that impacted unit startup. Sections 4 through 8 assess BP's systems for incident investigation, equipment design, pressure relief and disposal, trailer siting, and mechanical integrity. Because the organizational and cultural causes of the disaster are central to understanding why the incident occurred, BP's safety culture is examined in these sections. Section 9 details BP's approach to safety, organizational changes, corporate oversight, and responses to mounting safety problems at Texas City. Section 10 analyzes BP's safety culture and the connection to the management system deficiencies. Regulatory analysis in Section 11 examines the effectiveness of

[12] On August 10, 2005, the BP Texas City refinery experienced the third major mechanical integrity-related incident of that year, this one in the Cat Feed Hydrotreating Unit (CFHU); it resulted in a shelter-in-place order and $2 million in property damage.

OSHA’s enforcement of process safety regulations in Texas City and other high hazard facilities. The investigation’s root causes and recommendations are found in Sections 12 and 13. The Appendices provide technical information in greater depth.

2.0 INCIDENT OVERVIEW

2.1 BP Corporate and Texas City Refinery Background

On March 23, 2005, an explosion and fires occurred at the BP refinery in Texas City, Texas, 30 miles southeast of Houston. The refinery, the company's largest worldwide, can produce about 10 million gallons of gasoline per day (about 2.5 percent of the gasoline sold in the United States) for markets primarily in the Southeast, Midwest, and along the East Coast. It also produces jet fuels, diesel fuels, and chemical feed stocks; 29 oil refining units and four chemical units cover its 1,200 acre site. The refinery employs approximately 1,800 BP workers, and at the time of the incident, approximately 800 contractor workers were onsite supporting turnaround[13] work. The site has also had numerous changes in management at both the refinery and corporate levels. (Appendix D provides details on how the site changed from its commissioning to the date of the explosion.)

The Texas City facility is one of five U.S. refineries owned by BP; its others are in Whiting, Indiana; Carson, California; Cherry Point, Washington; and Toledo, Ohio.

2.2 ISOM Unit Process

The incident occurred while a section of the refinery's ISOM unit was being restarted after a maintenance turnaround that lasted one month. The ISOM unit, installed at the refinery in the mid-1980s to provide higher octane components for unleaded gasoline, consists of four sections: an Ultrafiner[14] desulfurizer, a

[13] In petroleum refining, a turnaround is the shutdown of a process unit after a normal run for maintenance and repair, then putting the unit back into operation (Parker, 1994).

[14] Ultrafining is a licensed process developed by Standard Oil of Indiana to desulfurize and hydrogenate refinery feedstocks from naphtha to lubrication oils using a regenerative fixed-bed catalyst.

Penex[15] reactor, a vapor recovery/liquid recycle unit, and a raffinate splitter. Isomerization is a refining process that alters the fundamental arrangement of atoms in the molecule without adding or removing anything from the original material. At the BP Texas City refinery, the ISOM unit converted straight-chain normal pentane and hexane into higher octane branched-chain isopentane and isohexane for gasoline blending and chemical feedstocks. (Appendix E provides historical information on the ISOM unit and the refinery.)

2.2.1 Raffinate Splitter Section

On the day of the incident, the startup of the ISOM raffinate splitter section was initiated. It was during this startup that the tower was overfilled with liquid. This section describes the relevant equipment involved in the startup on March 23, 2005.

The raffinate splitter section took raffinate -- a non-aromatic, primarily straight-chain hydrocarbon mixture -- from the Aromatics Recovery Unit (ARU) and separated it into light and heavy components. About 40 percent of the raffinate feed was recovered as light raffinate (primarily pentane/hexane). The remaining raffinate feed was recovered as heavy raffinate, which was used as a chemicals feedstock, JP-4 jet fuel, or blended into unleaded gasoline. The raffinate splitter section ccould process up to 45,000 barrels per day (bpd)[16] of raffinate feed.

[15] Penex is a licensed fixed–bed process developed by Universal Oil Products (UOP) that uses high-activity chloride-promoted catalysts to isomerize C5/C6 paraffins to higher octane branched components.

[16] One barrel equals 42 US gallons, or 159 liters.

The process equipment in the raffinate splitter section (Figure 1) consisted of a feed surge drum; a distillation tower; a furnace with two heating sections, one used as a reboiler for heating the bottoms of the tower and the other preheating the feed; air-cooled fin fan condensers and an overhead reflux drum; various pumps; and heat exchangers. (Appendix E provides details on the history of the raffinate splitter section.)

2.2.2 Raffinate Splitter Tower

The tower was a vertical distillation column with an inside diameter of 12.5 feet (3.8 m) and height of 170 feet (52 m) with an approximate liquid-full volume of 154,800 gallons (586,100 liters). The tower was fitted with 70 distillation trays[17] that separated the light from the heavy raffinate (Figure 1).

[17] A distillation tray has an opening at one end called a downcomer that allows liquid to flow down from the tray, and a series of bubble caps that allow vapors to pass through from below. Hydrocarbon liquid enters the tray from the downcomer of the tray above. The liquid entering the tray is aerated with the vapor rising from the tray below that is flowing through the bubble caps to form froth on the tray. The froth flows across the tray until it reaches an outlet weir. The froth flows over the weir into the downcomer, where the vapor is disengaged from the liquid (Kister, 1990, pg. 267).

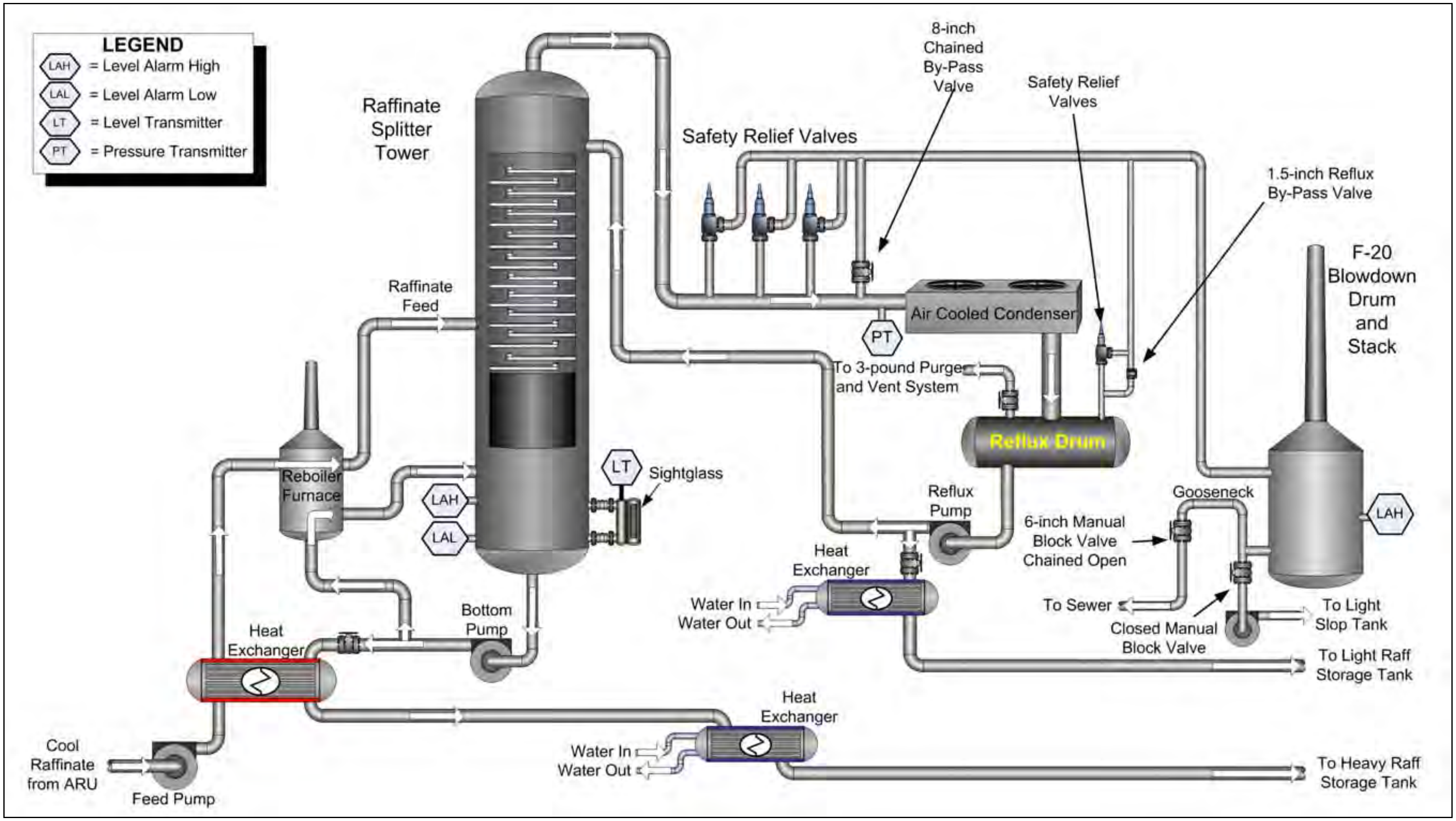

Figure 1. Raffinate section of the ISOM

Liquid raffinate feed was pumped into the raffinate splitter tower near the tower's midpoint. An automatic flow control valve adjusted the feed rate. The feed was pre-heated by a heat exchanger using heavy raffinate product and again in the preheat section of the reboiler furnace, which used refinery fuel gas. Heavy raffinate was pumped from the bottom of the raffinate splitter tower and circulated through the reboiler furnace, where it was heated and then returned below the bottom tray. Heavy raffinate product was also taken off as a side stream at the discharge of the circulation pump and sent to storage. The flow of this side stream was controlled by a level control valve that, when placed in "automatic," adjusted to maintain a constant level in the tower. The splitter tower was equipped with a level transmitter, which provided a reading of liquid level in the tower to the control room board operator.[18] The transmitter measured the tower's liquid level in a 5-foot (1.5-m) span within the bottom 9 feet (2.7 m) of the 170-foot (52-m) tall tower.The splitter tower also had two separate alarms that indicated high liquid level; one was programmed to sound when the transmitter reading reached 72 percent (a height of 7.6 feet or 2.3 meters in the tower). The second, a redundant hardwired high level switch,[19] was designed to sound when the liquid level reached 7.9 feet (2.4 m) in the tower (which corresponded to a reading of approximately 78 percent on the transmitter).The raffinate splitter was also fitted with a redundant low level alarm.

The heavy raffinate product side stream flowed through two heat exchangers, one that exchanged heat from the heavy raffinate with the colder incoming feed to the raffinate splitter, and a second that cooled the heavy raffinate feed using water, before the heavy raffinate was sent to storage or blending tanks.

[18] This reading was also used by the computerized control board system to adjust the position of the level control valve.

[19] The redundant hardwired high level switch was an independent instrument not connected to the level transmitter.

Light raffinate vapors flowed overhead and down a 148-foot (45-m) long section of pipe before they were condensed by the air-cooled fin fan condensers and then deposited into a reflux drum. Liquid from the reflux drum, called "reflux," was then pumped back up into the raffinate splitter tower above tray 1 (the top tray). The reflux drum was operated as a "flooded" drum, which means that during normal steady-state operation, it was kept completely full. The reflux drum also had high and low level alarms and a safety relief valve set at 70 psig (483 kPa). A bypass line, which discharged into the raffinate splitter disposal header collection system, allowed release of non-condensable gas (e.g. nitrogen) and purge the system. During startup, uncondensed vapors that built up in the drum were normally vented through a control valve to the refinery's 3-pound purge and vent gas system (Figure 1). This control valve malfunctioned and was not used during the March 23, 2005, startup.

2.2.3 Safety Relief Valves

To protect the raffinate splitter tower from overpressure, three parallel safety relief valves (Figure 2) were located in the overhead vapor line 148 feet (45 m) below the top of the tower. The outlet of the relief valves was piped to a disposal header collection system that discharged into a blowdown drum fitted with a vent stack.

The set pressures on these relief valves were 40, 41, and 42 psig (276, 283, and 290 kPa), respectively. An 8-inch NPS[20] (8.625-inch, 21.9 cm outer diameter) line, fitted with a manual chain valve, bypassed the safety relief valves and was used to release non-condensable gases and for system purging. The relief valves were designed to open and discharge primarily vapor into the raffinate splitter disposal header collection system when their set pressures were exceeded.

[20] NPS, or nominal pipe size, is a set of standard pipe sizes used for pressure piping in North America.

2.2.4 Disposal Header Collection Systems

The disposal header collection system received liquid and/or vapor hydrocarbons from venting relief and blowdown valves from equipment in the ISOM unit and discharged them to the blowdown drum. The header collection system included a 14-inch NPS (35.6 cm outer diameter) elevated pipe about 885 feet (270 m) long from the raffinate splitter tower (Figure 2). Other sections of the ISOM unit also discharged from two additional collection headers into the blowdown drum.

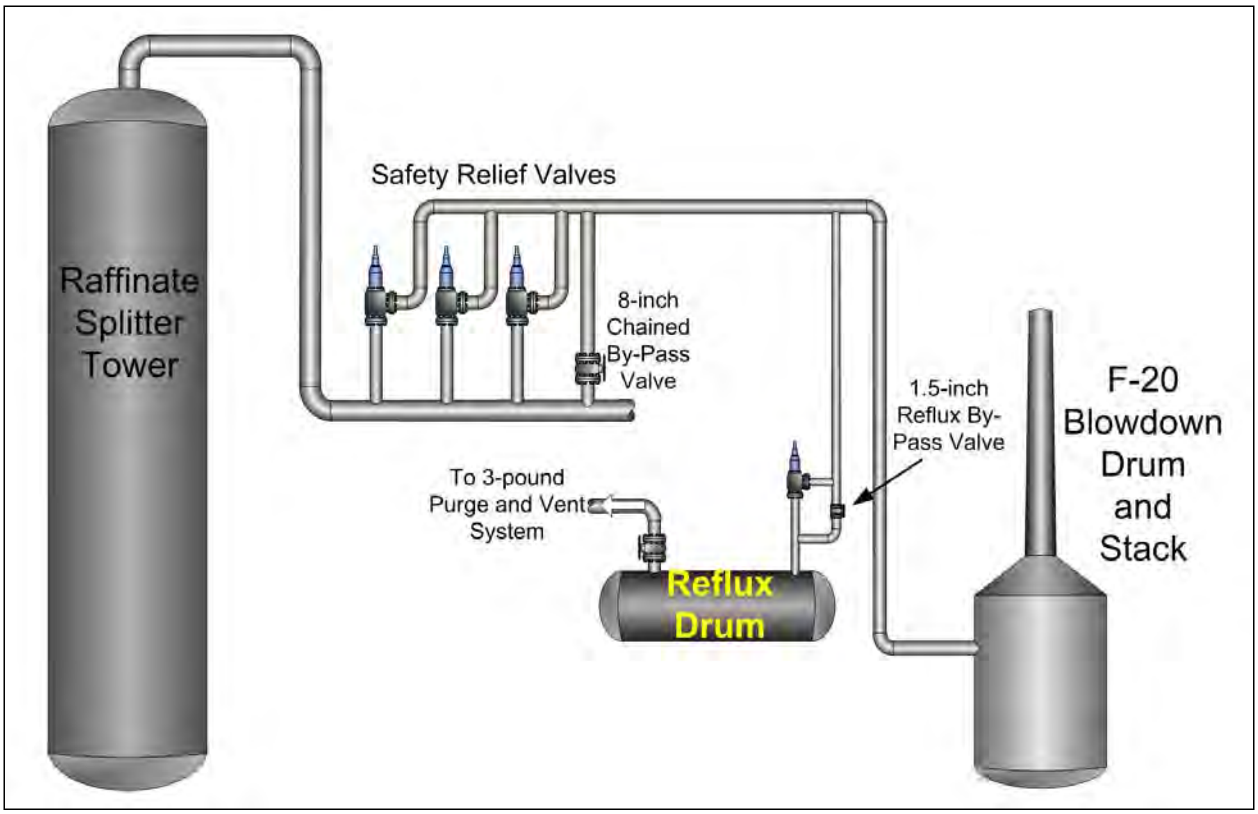

Figure 2. Disposal collection header system

2.2.5 Blowdown Drum and Stack

The blowdown drum and stack were designed to accept mixed liquid and/or vapor hydrocarbons from venting relief and blowdown valves during unit upsets or following a unit shutdown. In normal operation, light hydrocarbon vapors disengage from liquids, rise through a series of baffles, and disperse out the top of the stack into the atmosphere. Any liquids or heavy hydrocarbon vapors released into the drum either fall, or condense and then fall, to the bottom of the drum where they collect. Liquid would then be discharged from the base of the blowdown drum into the ISOM unit sewer system because a 6-inch NPS (6.625 inches; 15.24 cm outer diameter) manual block valve was chained open (Figures 3 and 4). This practice of discharging to the sewer was unsafe; industry safety guidelines recommend against discharging flammable liquids that evaporate readily into a sewer.[21]

The blowdown system, installed in the refinery in the 1950s, was a vertical drum with an inside diameter of 10 feet (3 m) and is 27 feet (8 m) tall. (Appendix E provides additional information on the blowdown system's history.) The drum wais fitted with a 34-inch (86 cm) diameter stack that discharged to the atmosphere at a height of 119 feet (36 m) off the ground. The approximate liquid full volume of the blowdown drum and stack was 22,800 gallons (86,200 L). The drum had seven internal baffles; the disposal collection header systems from the ISOM unit discharged into the drum below the lowest baffle.

A liquid level, normally water, was maintained in the bottom of the blowdown drum. The height of this level was controlled by a "gooseneck" seal leg piped to a closed drain (Figure 3 and 4).

A level sight glass was available to monitor the water level and a high level alarm was set to activate when the liquid level in the drum was close to flowing over the top of the gooseneck seal leg. A second manual block valve was located in a branch line of the blowdown drum discharge pipe (Figure 3). Following this valve, which was normally closed, was a manual steam-driven pump and a light slop tank.[22]

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[21] American Petroleum Institute (API) 1997. *Guide for Pressure-Relieving and Depressuring Systems,* API Recommended Practices 521, p. 52.

[22] A slop tank is a tank designated for collecting equipment drainings, tank washings, and other oily mixtures.

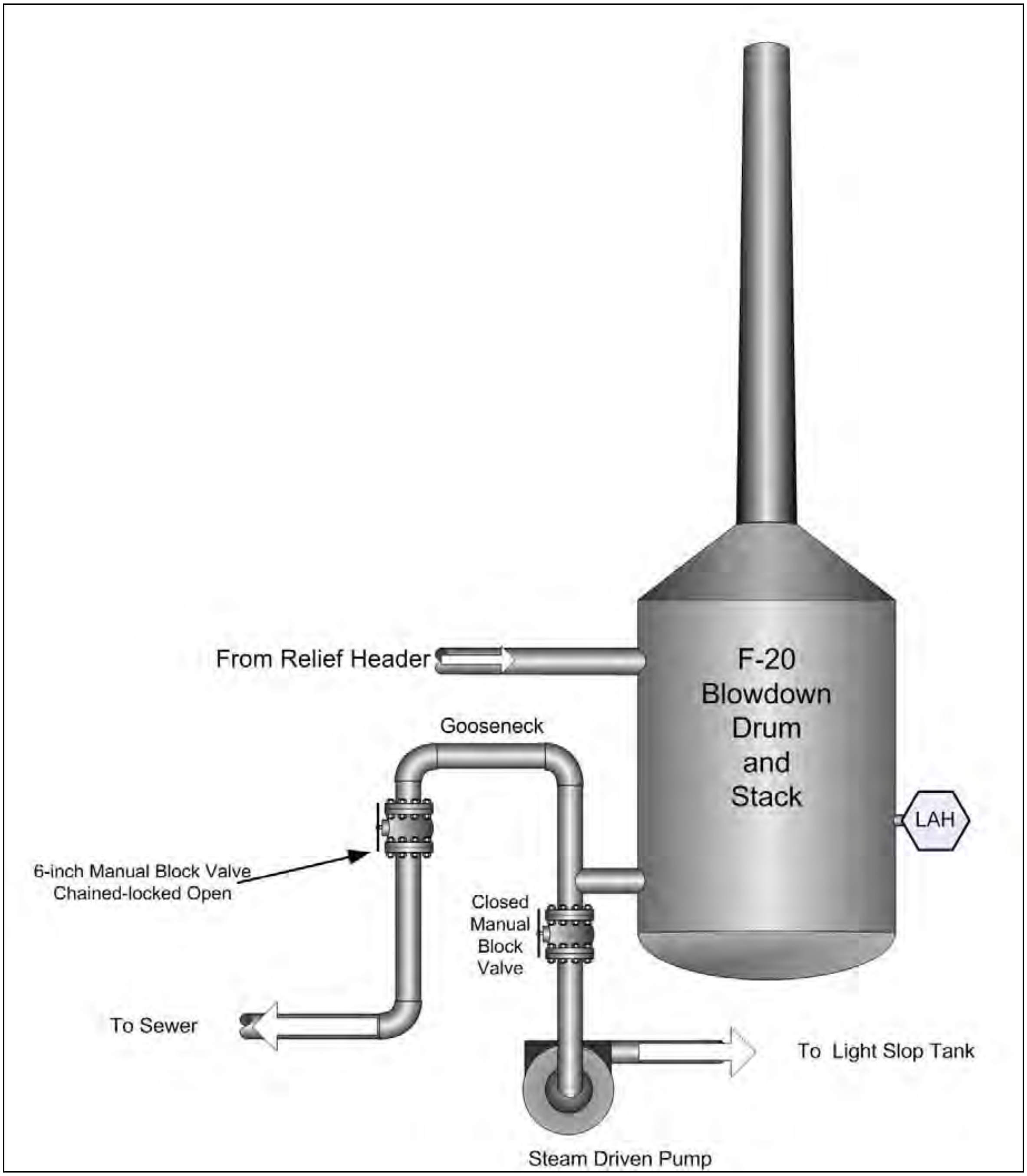

Figure 3. Blowdown drum and gooseneck

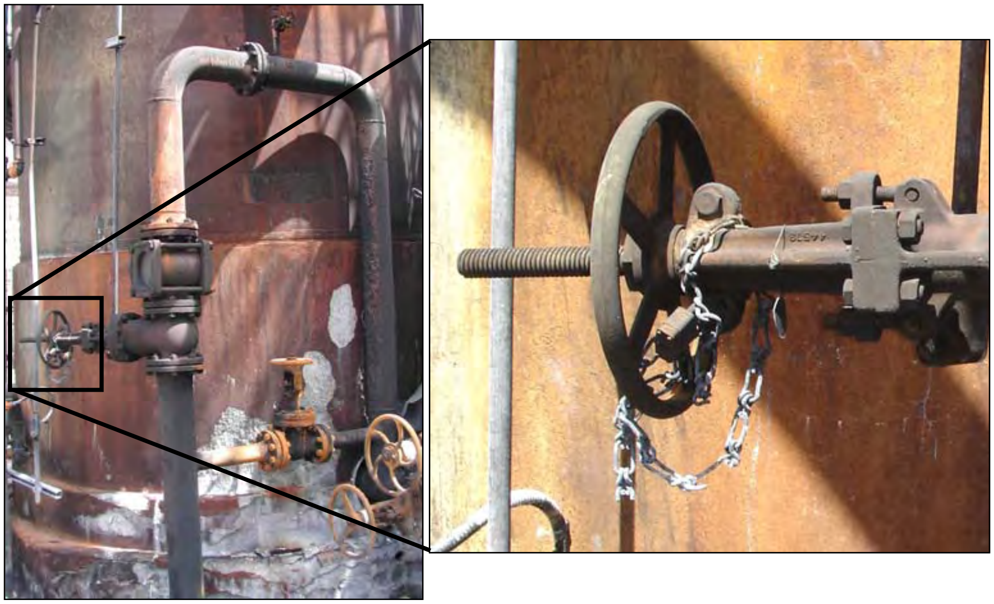

Figure 4. Left: Gooseneck piping and manual block valve (chained-locked open) Right:: Close-up of manual block valve

2.2.6 ISOM Unit Sewer System

While liquid raffinate discharged out the top of the blowdown stack, it also flowed into the process sewer system and into the west diversion box and oil/water separator, both fitted with high- and high-high level alarms.

2.3 Turnaround Activities

In early 2005, two major turnarounds were underway on units adjoining the ISOM unit.

2.3.1 Ultracracker Unit and Aromatics Recovery Unit Turnaround

Ultracracker unit (ULC) contractors were supporting a turnaround and BP sited a number of trailers for the contractors in the area next to the ISOM unit (Figure 5). (Appendix F provides further information on the location, construction, and use of these trailers.) The Aromatics Recovery Unit (ARU), which provides feedstock to the ISOM unit, was also undergoing a turnaround supported by contractors. These two turnarounds greatly increased the number of contractor and BP personnel in the area.

2.3.2 Partial ISOM Unit Shutdown

The raffinate splitter section of the ISOM unit was shut down on February 21, 2005, and the raffinate splitter tower was drained, purged, and steamed-out to remove hydrocarbons (Table 1). At the time of the incident most of the scheduled maintenance tasks had been completed on the raffinate splitter section, but the Penex reactor, in a separate section of the unit, was awaiting delivery of a gasket. When BP decided to start up the raffinate splitter section, three contractor crews were still working inside the battery limits[23] of the ISOM unit: one crew was waiting to install the gasket on the Penex reactor, the second was removing some asbestos, and the third was painting equipment inside the unit. Employees from all three crews were injured as a result of the explosion and fire.

[23] The battery limit is an area in a refinery or chemical plant encompassing a process unit or battery of units with their related utilities and services (Parker, 1994).

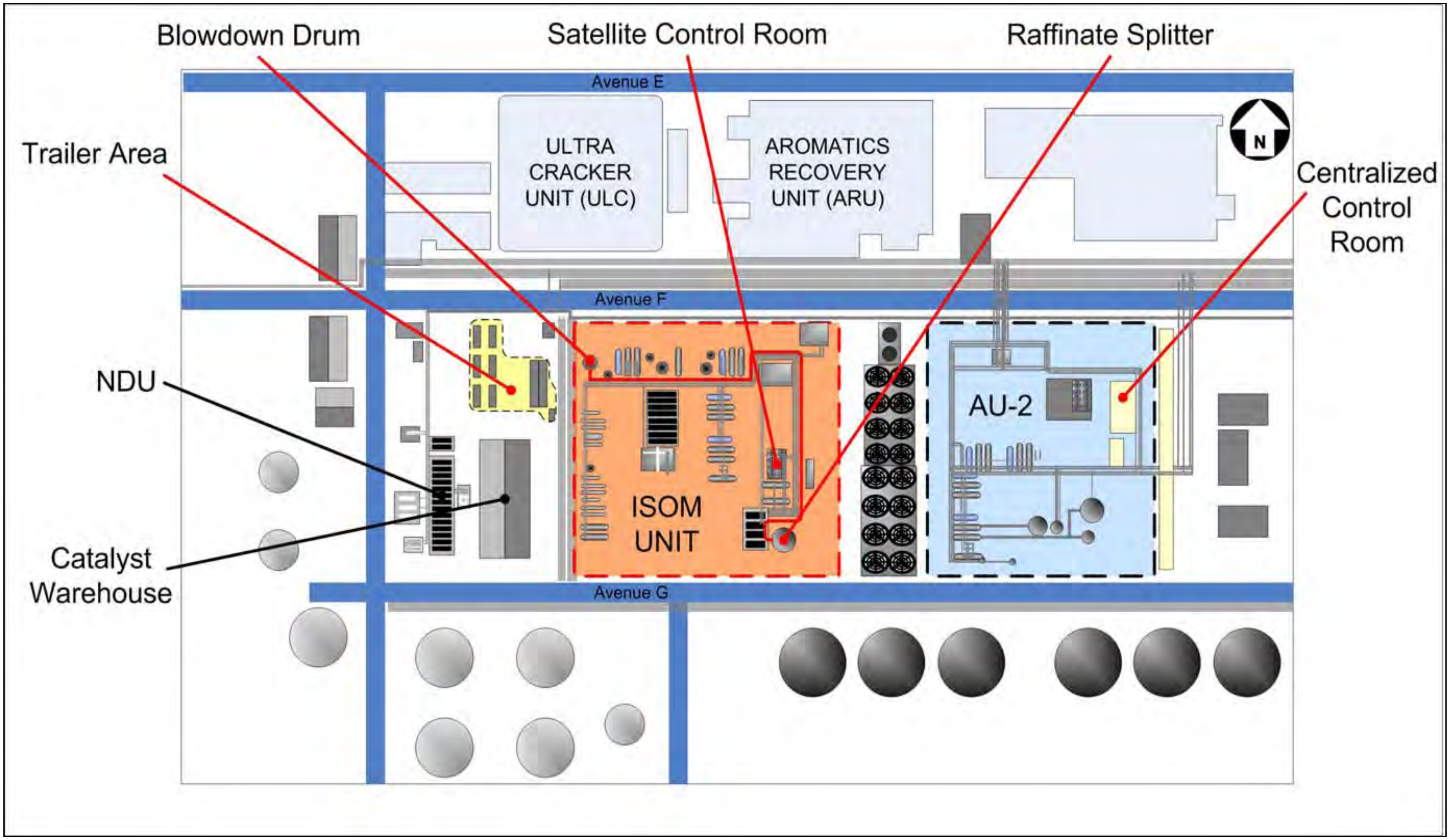

Figure 5. Refinery layout of the area surrounding the ISOM unit

Table 1. Timeline of events from ISOM unit shutdown to March 23 incident

Date	Time	Events
21-Feb-05		Raffinate splitter section of the ISOM unit is shut down; the 12-hour consecutive day shift schedule begins
26-Feb-05		Operators try to open/close the pressure control (3-pound) valve from the control board; valve is unresponsive
10-Mar-05		A revised work order to replace leaking isolation valves is added to the list of turnaround work so that the level transmitter can be fixed
22-Mar-05		Operators again try to open/close the 3-pound valve from the control board, but valve is unresponsive
22-Mar-05		Supervisor A tells instrument technicians to stop checking the critical alarms because the unit is starting up and there is not enough time to complete the checks
23-Mar-05	2:15 a.m.	The Night Lead Operator begins filling the tower with raffinate feed from the satellite control room
23-Mar-05	3:09 a.m.	The tower high level alarm sounds when the level in the tower reaches 7.6 ft in the tower (72% on the transmitter)
23-Mar-05		The redundant high level alarm switch does not sound when the tower level reaches 7.9 ft (78% on transmitter)
23-Mar-05		The Night Lead Operator fills the tower, stopping when the transmitter reads 99%, which should have been 8.95 ft (2.7 m) in the tower, but is actually 13.3 ft (4 m)
23-Mar-05	5:00 a.m.	The Night Lead Operator leaves the refinery a little over an hour before his scheduled shift leave time
23-Mar-05	6:06 a.m.	The Day Board Operator arrives at the refinery
23-Mar-05	6:23 a.m.	The Night Board Operator leaves the refinery
23-Mar-05	7:15 a.m.	Supervisor A arrives for his shift
23-Mar-05	9:27 a.m.	Operators open 8-inch NPS chain valve to remove nitrogen; the pressure in the tower drops to near 0 psig (0 kPa)
23-Mar-05		A verbal miscommunication occurs between operations personnel regarding feed-routing instructions
23-Mar-05	9:40 a.m.	The Day Board Operator opens the tower level control valve to 70% output for 3 minutes, then closes the valve
23-Mar-05	9:51 a.m.	Startup of the raffinate unit recommences and the tower begins receiving more feed from the ARU
23-Mar-05		The Day Board Operator observes a 97% transmitter reading (which should have been an 8.85 ft, or 2.7 m, tower level) when he starts circulation
23-Mar-05	9:55 a.m.	Two burners are lit in the raffinate furnace
23-Mar-05	10:47 a.m.	Supervisor A leaves the refinery due to a family emergency; no supervisor or technically trained personnel replaces him
23-Mar-05	11:16 a.m.	Two additional burners in the furnace are lit; the level transmitter reads 93%, which should have been a tower level of 8.65 ft (2.6 m); but is actually 67 ft. (20 m)
23-Mar-05	11:50 a.m.	Fuel to the furnace is increased; the actual tower level is 98 ft, but the transmitter reads 88% (8.4 ft.; 2.6 m)
23-Mar-05	12:41 p.m.	The tower's pressure rises to 33 psig (228 kPa); operators reduce pressure by opening the 8-inch NPS chain valve
23-Mar-05	12:42 p.m.	Fuel gas to the furnace is reduced; the actual tower level is 140 ft (43 m), but transmitter reads 80% (8 ft; 2.4 m)
23-Mar-05	12:42 p.m.	The Day Board Operator opens the tower level control valve to 15% output, then tries several times to increase output over the next 15 min.
23-Mar-05	12:45 p.m.	Approximately 25 people attend a safety meeting in the main control room until ~1:10 p.m.
23-Mar-05	12:59 p.m.	Heavy raffinate flow out of the unit finally begins
23-Mar-05	1:02 p.m.	Heavy raffinate flow out of the tower matches the flow of raffinate into the unit
23-Mar-05	1:04 p.m.	The actual level in the tower is 158 ft (48 m) but transmitter reading has declined to 78% (a level of 7.9 ft; 2.4 m)
23-Mar-05	1:11 p.m.	Supervisor A and Lead Operator talk; Supervisor suggests opening a bypass valve to relieve tower pressure
23-Mar-05	1:14 p.m.	Hydrocarbon flows out of the tower into overhead piping; tower pressure spikes to 63 psig (434 kPa); all three relief valves open
23-Mar-05		The Board Operator begins troubleshooting the pressure spike; he notices the drum alarm had not sounded, so he resumes moves to reduce pressure believing there is a residual buildup of noncombustibles in the tower
23-Mar-05	1:15 p.m.	Fuel gas to the furnace is reduced
23-Mar-05	1:16 p.m.	The Board Operator fully opens the heavy raffinate level control valve
23-Mar-05	1:17 p.m.	The overhead reflux pump is started by outside operators
23-Mar-05	1:19:59 p.m.	The Day Lead Operator shuts off fuel gas to the furnace from the satellite control room
23-Mar-05	1:20:04 p.m.	Vapor cloud ignites and explodes

2.4 The Hazards of Unit Startup

Process unit startup is a significantly more hazardous period compared to normal oil refinery operations. BP's Texas City policies and procedures acknowledged that process unit startup is especially hazardous, and as such, BP's process safety guidelines recommended that "supplementary assistance" be provided, such as experienced supervisors, operating specialists, or technically trained personnel during unit startups and shutdowns. [24] A basis for this policy was a previous explosion at Texas City during startup. The guidelines state that startup and shutdown are two of the most critical periods of plant operations,[25] and that these critical periods experience unexpected and unusual situations.[26] In 1996, Amoco analyzed data from 15 years of operations and concluded that incidents during startups were 10 times more likely than during normal operation. [27] Despite these guidelines and increased risks, BP did not have supplementary assistance personnel actively involved in the ISOM startup.

2.5 Incident Description

The incident occurred during the startup of the raffinate splitter section of the ISOM unit when the raffinate splitter tower was overfilled. Flammable liquid was released, vaporized, and ignited, resulting in

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[24] "Supervisory Personnel—Startups and Shutdowns," Process Safety Guideline No. 4, 1997. This guideline was labeled as an Amoco Petroleum Products document; however, BP had adopted Amoco's Texas City refinery heritage policies and procedures after the 1999 merger.

[25] See *Safe Ups and Downs for Process Units*, BP Process Safety Series (IChemE, 2005):"History shows that most of the serious refinery fires and explosions have occurred on units during startups and shutdowns," p. 3.

[26] Not only BP, but industry safety guidelines, recognize that startups are hazardous. The Center for Chemical Process Safety (CCPS), an industry-sponsored affiliate of the American Institute of Chemical Engineers that publishes widely recognized process safety guidelines, has determined that plant startup is when the majority of process safety incidents occur. CCPS states that even though startup represents only a small portion of the operating life of a plant, process safety incidents occur five times more often during startup than during normal operations. The 1998 Equilon Refinery accident in Anacortes, WA, with six fatalities; the United Kingdom 1994 Texaco Milford Haven explosion and fire; and the 2000 BP Grangemouth FCC unit fire are examples of major accidents that occurred during plant startup. *Guidelines for Safe Process Operations and Maintenance* (CCPS, 1995); p.113 citing *Large Property Damage Losses in the Hydrocarbon-Chemical Industries.* Marsh McLennan, 14th edition, New York, NY, 1992.

[27] Memo from the Director of Refining Process Safety, "Incident Rates for Amoco Process Units—Startups and Shutdowns Versus Normal Operations;" May 1, 1996.

an explosion and fire. The following section describes the events leading up to the incident, the resulting damage, and the emergency response activities.

2.5.1 Unit Staffing

When the ISOM unit was in normal operation, it and two other units were run by a board operator and three outside operators.[28] The outside operators were assigned to either the ISOM unit; the naphtha desulfurization unit (NDU); or the aromatics unit no. 2 (AU2). One board operator monitored all three from a central control room located in the AU2 (Figure 5). Each crew also had a frontline supervisor and a process technician (PT). Table 2 lists significant persons involved in unit startup.

While the ISOM unit was shut down, the operators were on a turnaround schedule and split into two crews working 12-hour shifts, which would continue for the duration of the shutdown and until the unit was back to normal operation after the shutdown. The ISOM day shift crew consisted of one board operator and five outside operators. The Day Shift Board Operator had six years experience operating the control board, including four startups in the last five years. Two of the five outside operators had over 15 years ISOM experience. One of these two operators was the Day Lead Operator, and had more than nine years of mostly board operator experience but was assigned to an outside operator role for the startup. This operator had been elevated to a lead position for the turnaround, but was not clearly assigned responsibility for leading the startup. The Day Lead Operator coordinated his tasks from the ISOM unit's satellite control room (Figure 5), which had a computer system that allowed him to monitor the ISOM control board.

[28] As the NDU, AU2, and ISOM normally operate continuously, a total of four crews working rotating 12-hour shifts is needed to staff the units. The four frontline supervisors, an operations coordinator, a turnaround coordinator, and a training coordinator report to the unit superintendent. The coordinators and superintendent work the day shift.

Table 2. Individuals involved in the March 23, 2005, startup

Job Position	Description
Texas City Managers	Managers above the frontline supervisor level
Shift Director	Site operations coordinator responsible for executing the daily operation plan
Process Technician (PT)	Experienced operators who held floating positions, performing tasks as needed, including assisting on the control board or outside operators in the process units.
Night Supervisor	Frontline supervisor involved in the turnaround activities of the ARU during the night shift prior to the incident
Day Supervisor A	ISOM-experienced frontline supervisor; left the refinery for a family emergency
Day Supervisor B	Inexperienced frontline supervisor for AU2/ISOM/NDU complex and the ARU; involved primarily in turnaround activities of the adjacent unit
Night Lead Operator	Began the startup process in the satellite control room during the early morning hours of March 23
Day Lead Operator	ISOM-experienced board operator working as an outside operator during turnaround; responsible for managing contractors, finding replacement equipment for ISOM, and training two new operators
Night Board Operator	Controlled the NDU and AU2 units in the centralized control room during the shift prior to the incident
Day Board Operator	Responsible for monitoring and controlling the AU2,NDU, and ISOM units, including the raffinate section startup, on March 23 from a centralized control room in the AU2 unit
Outside Operators	Operators performing manual tasks on unit equipment
Operations Personnel	Operators and frontline supervisors

The other experienced outside operator had little board operator experience. The three remaining outside operators were inexperienced; one had worked in the ISOM for seven months, and two were unit trainees. The shift started with two supervisors: one with 20 years ISOM experience, the second with none.

The two PTs typically assigned to the ISOM/NDU/AU2 unit were delegated to work in the ARU; these experienced and knowledgeable operators did not help with the ISOM unit startup. The startup of the raffinate section of the ISOM unit took place over two shifts: the night shift on March 22, 2005, and the day shift that began at 6 a.m. on March 23.

2.5.2 Preparations for the ISOM Startup

A number of safety-critical steps were required prior to introducing hydrocarbons into the splitter tower. These steps, as listed in the startup procedures, included completing maintenance work, performing required safety reviews, checking equipment, and ensuring that utilities, control valves, and other equipment were functioning and correctly aligned.

2.5.2.1 Pre-Startup Safety Review (PSSR)

BP had used a rigorous pre-startup procedure prior to the incident that required all startups after turnarounds to go through a PSSR.[29] While the PSSR had been applied to unit startups after turnarounds for two years prior to this incident, the process safety coordinator responsible for an area of the refinery that includes the ISOM was unfamiliar with its applicability, and therefore, no PSSR procedure was conducted. If the PSSR, which called for a formal safety review by a technical team led by the operations superintendent, had been implemented, a technical team would have verified the adequacy of all ISOM safety systems and equipment, including procedures and training, process safety information, alarms and equipment functionality, and instrument testing and calibration. The PSSR required sign-off that all non-essential personnel had been removed from the unit and neighboring units and that the operations crew had reviewed the startup procedure. Higher level management, such as the Texas City Operations Manager and Process Safety Manager, were required to sign off on the PSSR checklists and authorize the startup. However, none of the PSSR procedural steps were undertaken for the ISOM startup.

[29] The BP Texas City “Formal Pre-Startup Safety Review” policy (marked “For Comment”), PSM-7.0, required a formal PSSR prior to startup following a turnaround. The policy defined a turnaround “as any shutdown that requires feed to be pulled from the unit or a section of the unit and equipment to be prepared or opened for maintenance.” The ISOM raffinate section maintenance work prior to the March 23, 2005, incident would qualify as a turnaround under this policy. Equipment, such as the E-1101 splitter tower and the F-1101 feed surge drum, was deinventoried, steamed-out, and opened for maintenance. While PSM-7.0 was not formally adopted until after the incident, it had been applied to the startups after turnarounds for the two years prior to the ISOM incident.

2.5.2.2 Needed Pre-Startup Instrumentation and Equipment Repairs

During pre-startup equipment checks, key splitter tower instrumentation and equipment were identified as malfunctioning but were not repaired. During the ISOM turnaround, operations personnel reported to turnaround supervisors that the splitter level transmitter and level sight glass needed repair.[30] This equipment could not be repaired when the unit was operating, as the block valves needed to isolate the level transmitter and the sight glass from the process were leaking. As a result, on March 10, 2005, a revised work order was issued that added replacement of the isolation block valves to the turnaround job list. The level transmitter was not repaired because BP supervisors determined that there was too little time to complete the job in the existing turnaround schedule. The isolation valves were replaced during the turnaround; BP supervisors planned to repair the level transmitter after the startup.

Both during unit shutdown and the equipment checks in the days preceding raffinate splitter startup, operations personnel found that a pressure control valve[31] was inoperable. On February 26 and March 22, 2005, operators tried to open and close the control valve from the control board, but the outside operators saw that it did not move. The malfunctioning control valve was reported to a frontline supervisor; however, no work order was written and no repairs were made prior to startup. This same frontline supervisor signed off on the startup procedure that all control valves had been tested and were operational prior to startup.

A functionality check of all alarms and instruments was also required prior to startup, but these checks were not completed. On March 22, 2005, instrument technicians had begun checking the critical alarms when a supervisor told them that the unit was starting up and there was no time for additional checks.

[30] The raffinate splitter tower level transmitter was reported by operations personnel as providing inaccurate readings and needing calibration. The tower sight glass was reported as dirty on the inside of the glass so that the tower level could not be visually determined.

[31] The raffinate splitter tower pressure control valve, PV-5002, vents pressure and non-condensable gases to the 3-pound plant gas system from the reflux drum and splitter tower during startup but does not control pressure during normal operation.

While some alarms were tested, most were not prior to startup. The supervisor, however, initialed on the startup procedure that those checks had been completed.

Other key safety preparations listed in the startup procedures were omitted or ineffectively carried out. BP guidelines state that unit startup requires a thorough review of startup procedures by operators and supervisors;[32] however, this review was not performed. The procedure also called for adequate staffing for the startup and that any unsafe conditions be corrected. Both of these steps were initialed as being completed by a unit trainee at the direction of his supervisor.

2.5.3 Initial Tower Filling and Shutdown

BP supervision decided to initiate the startup of the ISOM unit raffinate section during the night shift on March 22, 2005. This decision was consistent with prior email communications by area supervision directing the turnaround work, stating that the raffinate section would be started when the ARU had returned to operation.[33] However, after the startup was begun, it was stopped and the raffinate section was shut down to be re-started during the next shift. Starting, but then stopping, the unit was unusual and not covered in the startup procedures, which only addressed one continuous startup.

The Night Lead Operator controlled filling the raffinate section from the satellite control room because it was close to the process equipment. The Night Board Operator controlled the other two process units from the central control room. The Night Lead Operator did not use the startup procedure or record completed steps for the process of filling the raffinate section equipment, which left no record of the startup steps completed for the operators on the next shift.

[32] *Safe Ups and Downs for Process Units*, BP Process Safety Series (IChemE, 2005); p. 28.

[33] The ARU had just been started up from a major turnaround and some ARU operational problems were still being addressed.

As stated earlier, the splitter tower was equipped with a level transmitter that measured the tower's liquid level in a 5-foot (1.5 m) span within the bottom 9 feet (2.7 m) of the 170-foot (52-m) tall tower. The splitter tower also had two separate alarms; one was programmed to sound when the transmitter reading reached 72 percent (a height of 7.6 feet or 2.3 meters in the tower), and the other was a redundant high level alarm that was designed to sound when tower level reached 7.9 feet or 2.4 meters (an approximate transmitter reading of 78 percent). However, when the raffinate splitter tower was filled beyond the set points of both alarms to a level reading of 99 percent on the transmitter in the early morning on March 23, 2005,[34] only one alarm was activated. The high level alarm was triggered at 3:09 a.m.. The redundant hardwired high level alarm never sounded. Material balance calculations conducted post-incident determined that the tower had actually filled to 13 feet (4 m), four feet over the top tap of the level transmitter. Because the failure of the high level switch was unnoticed, it was not reported by the Night Lead Operator or other operations personnel; consequently, no work order was written and the malfunction was not noted in the logbook. The high level alarm associated with the level transmitter remained in the alarmed state throughout the incident.

Filling the bottom of the tower until the level transmitter read 99 percent was not unusual, even though the startup procedure called for the level in the tower to be established at a 50 percent transmitter reading. Operations personnel explained that additional liquid level was needed in the tower because in past startups the level would typically drop significantly. To avoid losing the liquid contents of the tower and potentially damaging equipment, board operators typically operated the tower level well above 50 percent.

[34] At 1:57 a.m., liquid hydrocarbons from the ARU were introduced into the raffinate section equipment; at 2:15 a.m., hydrocarbon feed was flowing to the raffinate splitter tower and the liquid level began to rise at 2:27 a.m.

Once the raffinate section equipment was filled, the startup was stopped and the splitter tower feed and bottoms pumps shut off. The circulation was shut down and the tower level control valve remained in the "closed" position for the next shift to resume the startup.[35]

2.5.4 Inadequate Shift Turnover

Shortly before 5:00 a.m. on March 23, 2005, the Night Lead Operator left the Texas City refinery approximately an hour before his scheduled shift end time. He told his supervisor and the Night Board Operator that he was leaving, and briefly described the actions he had taken in the satellite control room. The following entry was added to the centralized control room logbook: "ISOM: Brought in some raff to unit, to pack raff with."[36]

When the Day Board Operator changed shifts in the central control room with the Night Board Operator shortly after 6:00 a.m., he received very little information on the state of the unit. The Day Board and Night Board Operators spoke to each other, but because the Night Board Operator was not the one who filled the tower, he provided few details about the night shift's raffinate section startup activities other than what was written in the logbook.

The Day Board Operator read the logbook and interpreted the entry to mean that liquid was added only to the tower; the Day Board Operator, in post-incident testimony, said that he was unaware that the heat exchangers, the piping, and associated equipment had also been filled during the previous shift. The ISOM-experienced Day Supervisor, Supervisor A, arrived for his shift at approximately 7:15 a.m., more than an hour late, and did not conduct shift turnover[37] with any night shift personnel.

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[35] These actions were not part of the startup procedure, which instructed that, after a level was established in the splitter tower, the tower level control valve was to be placed in "automatic" and set at 50 percent to establish heavy raffinate flow from the bottom of the tower to storage.

[36] The term "pack" is jargon used in the refinery; to "pack" a piece of equipment is to fill it with product; in this case, with liquid raffinate feedstock.

[37] Shift turnover is when the operator of the outgoing shift shares information with the operator of the incoming shift regarding the current status of the unit and any problems or concerns noted during that shift.

2.5.5 Raffinate Tower Startup

On the morning of March 23, the raffinate tower startup began with a series of miscommunications. The early morning shift directors' meeting discussed the raffinate startup, and Day Supervisor B, who lacked ISOM experience, was told that startup could not proceed because the storage tanks that received raffinate from the splitter tower were believed to be full. The Shift Director stated in post-incident interviews that the meeting ended with the understanding that the raffinate section would not be started. This decision was consistent with a March 22 storage tank area logbook entry that stated the heavy raffinate tank was filling up.[38] The instruction to not start the raffinate section was not communicated to the ISOM operations personnel.[39]

Day Supervisor A told the operations crew that the raffinate section would be started. Because the startup procedure that should have provided information on the progress of the startup by the night shift was not filled out and did not provide instructions for a non-continual startup, the Day Board Operator had no precise information of what steps the night crew had completed and what the day shift was to do.

Day Supervisor A did not distribute or review the applicable startup procedure with the crew, despite being required to do so in the procedure.

Before sending additional liquid hydrocarbons to the raffinate section, outside operators opened the 8-inch NPS chain-operated valve to remove nitrogen from the splitter tower system. At 9:27 a.m., the pressure in the tower dropped to near 0 psig (0 kPa). The startup procedure called for lowering system pressure to a minimum to help prevent over-pressuring the tower during startup by removing the nitrogen that remained in the system following the purging of air from the raffinate equipment.

[38] The storage tank area log book dated March 22, 2005 stated "*Filling up on RAFF 538, 36 [heavy raffinate storage tanks]."

[39] No BP managers other than frontline supervisors have acknowledged authorizing the startup.

Prior to re-commencing the startup, a miscommunication occurred regarding how feed and product would be routed into and out of the unit (Section 3.2). The Day Board Operator believed he was instructed not to send heavy raffinate product to storage and therefore closed the tower level control valve. However, the outside operators believed they were instructed not to send the light raffinate product to storage and manually changed the valve positions so that light raffinate would flow into the heavy raffinate product line. Moreover, no feed or product-routing instructions were entered into the startup procedure or the unit logbook. The CSB determined that the miscommunication likely concerned whether the light or heavy raffinate tanks were full and unavailable to receive additional liquid.

Prior to the restart at 9:40 a.m., the Day Board Operator opened the splitter tower level control valve to 70 percent output, and for three minutes 12,000 bpd of heavy raffinate flowed out of the tower. Then he closed the level control valve, which went to 0 percent output, but the heavy raffinate flow indication dropped only to 4,300 bpd rather than 0 bpd. The flow indication was erroneous, and little or no heavy raffinate flowed from the tower. Startup resumed at 9:51 a.m. Even though the Day Board Operator did not have the benefit of a written procedure with the completed steps initialed to indicate the exact stage of the startup, raffinate circulation was restarted and feed introduced into the splitter tower, which already had a high liquid level.

The Day Board Operator, acting on what he believed were the unit's verbal startup instructions and his understanding of the need to maintain a higher level in the tower to protect downstream equipment,[40] closed the level control valve. However, the startup procedure required the level control valve to be placed in "automatic" and set at 50 percent to establish heavy raffinate flow to storage. The Day Board Operator said that, from his experience, when the splitter tower bottoms pumps were started and associated equipment filled, the tower level dropped. Operations personnel stated that if the level was

[40] A loss of heavy raffinate flow out the bottom of tower had the potential to damage the furnace tubes in the fired heater. The raffinate furnace was equipped with a low flow alarm and furnace trip to protect the tubes against overheating. The trip shut down the furnace by closing the fuel gas control valve.

maintained at only 50 percent, a drop in liquid level could result in losing heavy raffinate flow from the bottom of the tower, and that loss of flow from the tower bottom's pump to the furnace would shut down the furnace and the startup process. The Day Board Operator observed a 97 percent level when he started circulation and thought that this level was normal; he said he did not recall observing a startup where the level was as low as 50 percent. At 10:10 a.m., 20,000 bpd of raffinate feed was being pumped into the tower and 4,100 bpd was erroneously indicated as leaving the tower through the level control valve. The Day Board Operator said he was aware that the level control valve was shut. After examining control board data, CSB concludes that there was likely no flow out of the tower at this time.

2.5.6 Tower Overfills

The tower instrumentation continued to show a liquid level less than 100 percent of the range of the transmitter. The level sight glass, used to visually verify the tower level, had been reported by operators as unreadable because of a buildup of dark residue; the sight glass had been nonfunctional for several years. Knowing the condition of the sight glass, the Day Board Operator did not ask the outside crew to visually confirm the level. Even though the tower level control valve was not at 50 percent in "automatic" mode, as required by the startup procedure, the Day Board Operator said he believed the condition was safe as long as he kept the level within the reading range (span) of the transmitter.

As the unit was being heated, the Day Supervisor, an experienced ISOM operator, left the plant at 10:47 a.m. due to a family emergency. The second Day Supervisor was devoting most of his attention to the final stages of the ARU startup; he had very little ISOM experience and, therefore, did not get involved in the ISOM startup. No experienced supervisor or ISOM technical expert was assigned to the raffinate section startup after the Day Supervisor left, although BP's safety procedures required such oversight.

The Day Board Operator continued the liquid flow to the splitter tower, but was unaware that the actual tower level continued to rise. At 9:55 a.m., two burners were lit in the raffinate furnace,[41] which pre-heated the feed flowing into the splitter tower and served as a reboiler, heating the liquid in the tower bottom (Figure 1). At 11:16 a.m., operators lit two additional burners in the furnace. While the transmitter indicated that the tower level was at 93 percent (8.65 feet; 2.64 m) in the bottom 9 feet of the tower, the CSB determined from post-incident analysis that the actual level in the tower was 67 feet (20 m). The fuel to the furnace was increased at 11:50 a.m., at which time the actual tower level was 98 feet (30 m), although the transmitter indicated that the level was 88 percent (8.4 feet; 2. 6 m) and decreasing.

At 12:41 p.m., the tower's pressure rose to 33 pounds (psig) (228 kPa), due to the significant increase in the liquid level compressing the remaining nitrogen in the raffinate system. The operations crew, however, believed the high pressure to be a result of the tower bottoms overheating, which was not unusual in previous startups. In response to the high pressure, the outside operations crew opened the 8-inch NPS chain-operated valve that vented directly to the blowdown drum, which reduced the pressure in the tower.

The startup procedure called for heating the raffinate splitter tower reboiler return flow to 275°F (135°C) at no more than 50°F (10°C) per hour to avoid excessive pressure in the tower. However, during this startup the temperature of the reboiler return to the tower rose as high as 307°F (153°C), and from 10 a.m. to 1 p.m. the temperature increased at a rate of 73°F (23°C) per hour. In the previous five years, most of the 19 startups had deviated from written procedures. In the majority, the reboiler return was heated above 275°F (135°C) and had temperature increase rates of over 100°F (38°C) per hour; in five, the reboiler return was heated to over 290°F (143°C); and in six of these startups, temperatures increased at rates in excess of 150°F (66°C) per hour.

[41] The direct fired reboiler did not allow fine control of the heating rate. Burners had to be brought on- and off-line manually to adjust the heating rate.

The Day Board Operator and the Day Lead Operator agreed that the heat to the furnace should be reduced, and at 12:42 p.m. fuel gas flow was reduced to the furnace. At this time the raffinate splitter level transmitter displayed 80 percent (8 feet; 2.4 m) but the actual tower level was 140 feet (43 m).

From 10 a.m. to 1 p.m. the transmitter showed the tower level declining from 97 to 79 percent.[42] The Day Board Operator thought the level indication was accurate, and believed it was normal to see the level drop as the tower heated up. At the time of the pressure upset, the Day Board Operator became concerned about the lack of heavy raffinate flow out of the tower, and discussed with the Day Lead Operator the need to remove heavy raffinate from the raffinate splitter tower. None of the ISOM operators knew the tower was overfilling. At 12:42 p.m., the Day Board Operator opened the splitter level control to 15 percent output, and over the next 15 minutes opened the valve five times until, at 1:02 p.m., it was 70 percent open. However, heavy raffinate flow had not actually begun until 12:59 p.m.

The heavy raffinate flow out of the tower matched the feed into the tower (20,500 bpd) at 1:02 p.m. and by 1:04 p.m. had increased to 27,500 bpd. Unknown to the operators, the level of liquid in the 170-foot (52 m) tower at this time was 158 feet (48 m), but the level transmitter reading had continued to decrease and now read 78 percent (7.9 feet; 2.4 m) (Figure 6). Although the total quantity of material in the tower had begun to decrease, heating the column contents caused the liquid level at the top of the column to continue increasing until it completely filled the column and spilled over into the overhead vapor line leading to the column relief valves and condenser.

[42] The level transmitter output was expressed as a percentage of the transmitter's measurement span of approximately 5 feet in the bottom section of the column.

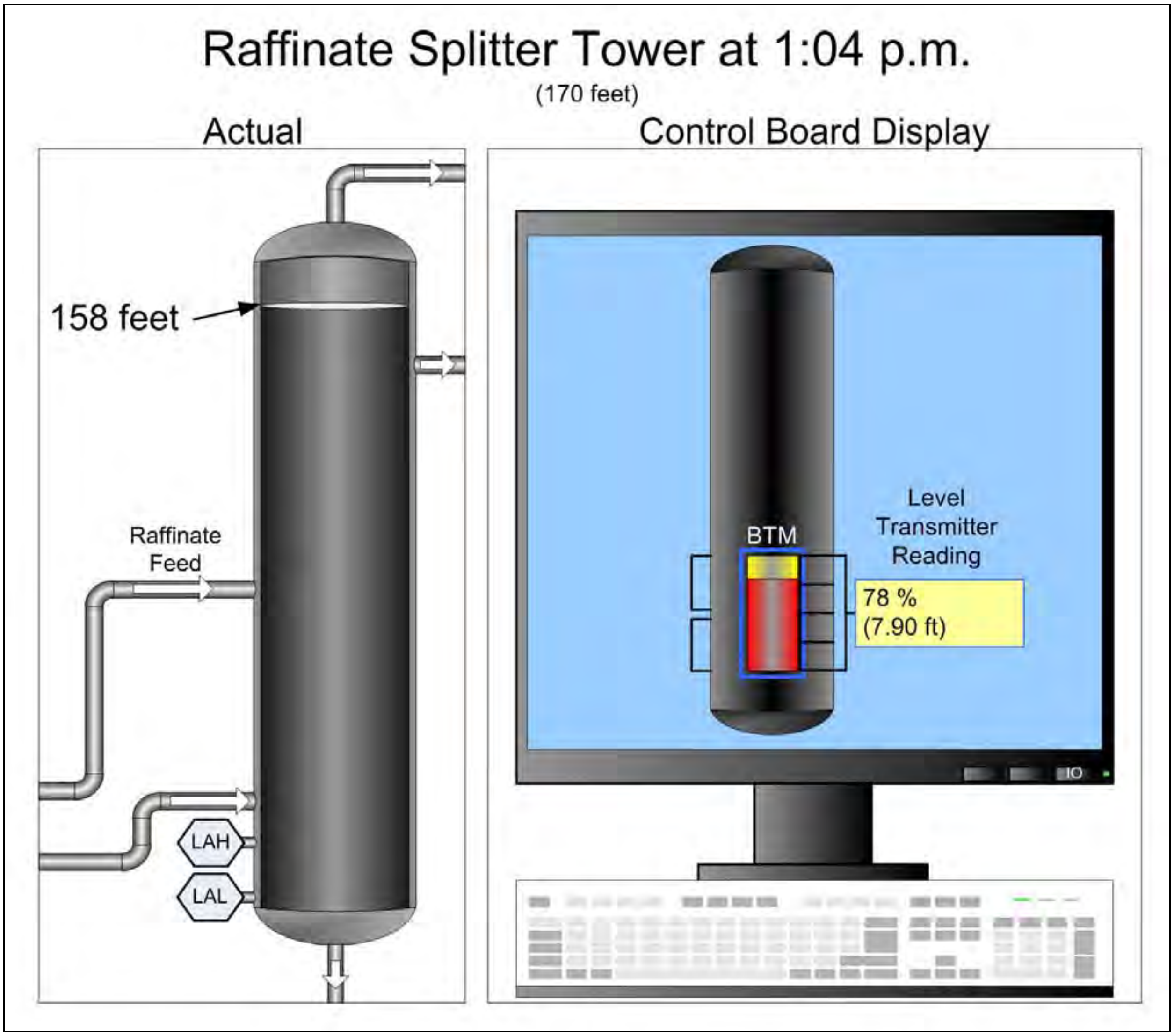

Figure 6. At 1:04 p.m. the liquid level in the tower was 158 feet (48 m), but the computerized control system indicated to operators that the level was at 78 percent of the level transmitter (7.9 feet, or 2.4 m, of liquid in the tower).

2.5.7 Tower Overflows

At 1:14 p.m., sub-cooled[43] hydrocarbon liquid flowed out of the top of the raffinate splitter tower and into the vertical overhead vapor line, due to overfilling and rapid heating of the column (Figure 7).

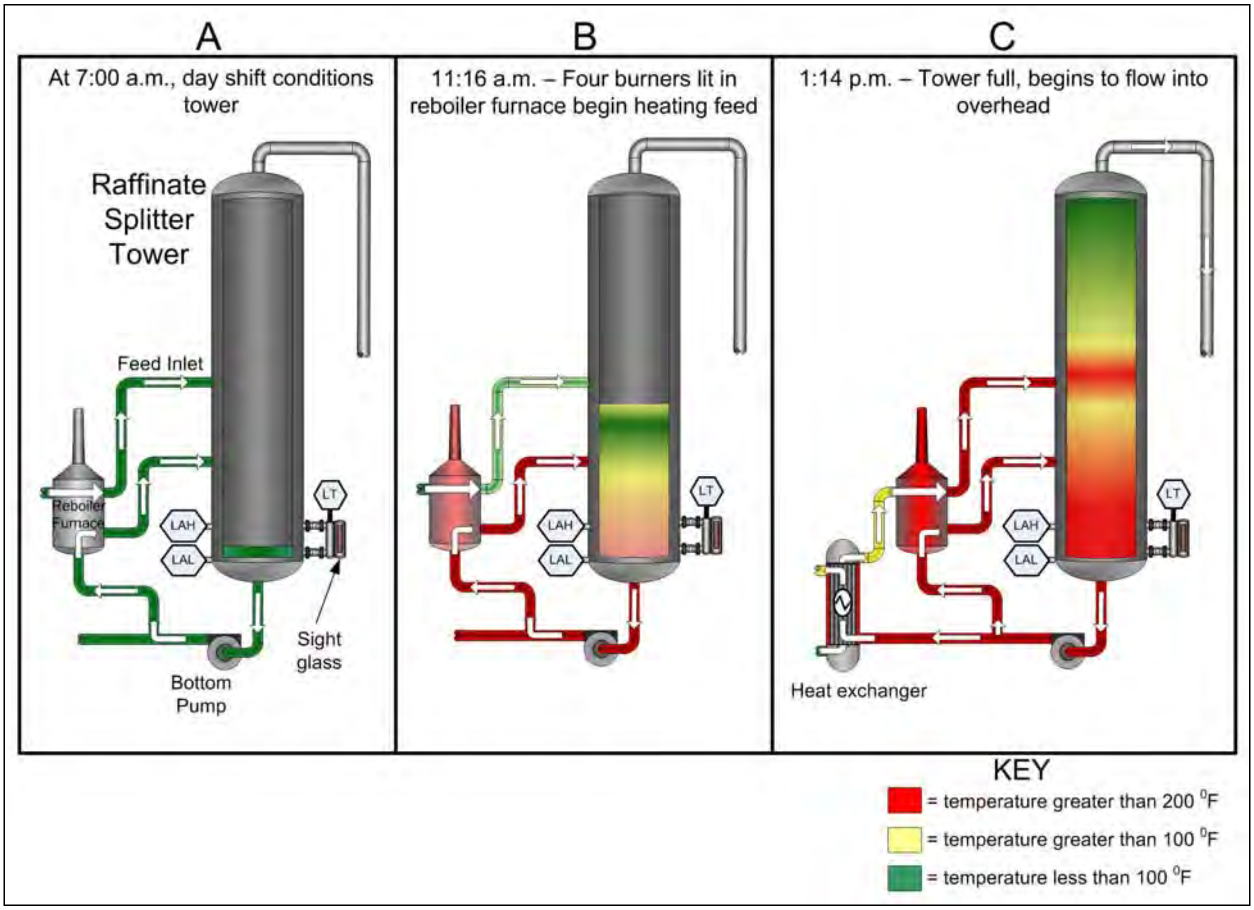

Figure 7. Heating of feed in the splitter tower

Heating from the furnace had created a temperature profile in the raffinate splitter column, such that cold liquid was on top and hot liquid was in the lower section (Figure 7B). Bubbles of hot vapor rising through the column contacted the overlying cold liquid, rapidly condensing the vapor and heating the liquid. At the time of the incident, the resulting hot liquid reached nearly to the level of the feed inlet. Hot liquid

[43] A sub-cooled liquid is below its saturation temperature. The saturation temperature is the temperature that a substance will change from a liquid to a gas, or vice versa.

raffinate leaving from the bottom of the column after 12:59 p.m. transferred additional heat to the column feed through the heat exchanger, leading to rapid heating of the section of the raffinate splitter column above the feed inlet. By the time of the incident, most of the column was rapidly heating, although a cold layer of liquid remained at the top (Figure 7C).

The increase in average column temperature reduced the density of the hydrocarbon liquid, significantly increasing the liquid level. As the entire column approached the boiling point of the liquid, the vapor bubbles accumulated instead of being rapidly condensed. The resulting increase in volume from vaporization caused the liquid at the column top to overflow into the vapor line (Appendix G).

2.5.8 Safety Relief Valves Open

As the liquid filled the overhead line, the resulting hydrostatic head[44] in the line increased. The tower pressure (which remained relatively constant) combined with the increased hydrostatic head and exceeded the set pressures of the safety relief valves. The valves opened and discharged liquid raffinate into the raffinate splitter disposal header collection system (Figure 8). Based on valve set pressure, post-incident valve testing, and computerized control system data, the first safety relief valve is estimated to have opened at 1:13:56 p.m., followed by the second at 1:14:10 p.m., and the third at 1:14:14 p.m. Both the Day Board Operator in the central control room and the outside operators in the satellite control room saw the splitter tower pressure rising rapidly to 63 psig (434 kPa); however, interviews revealed that the outside operators did not hear the three splitter tower relief valves open.[45]

The Day Board Operator began troubleshooting this pressure spike and announced on the unit radio that the blowdown drum's high level alarm had not sounded. The operations crew again believed the

[44] Hydrostatic head is the pressure per unit area (e.g. psi) that is exerted by a column of liquid.

[45] The operators likely did not hear the relief valves open because the sound normally comes from the vapor escaping through the relief valves; if liquid was being released through the relief valves, the sound would be significantly quieter.

overpressure was a result of buildup of noncondensible gases or lack of reflux. [46]Computerized control system data shows that the Day Board Operator reduced the fuel gas to the feed preheat furnace at 1:15:30 p.m., and fully opened the level control valve to heavy raffinate storage at 1:16:00 p.m. The Day Lead Operator told two outside operators to go out and start the reflux pump on the raffinate splitter; he then shut off the fuel gas to the furnace from the satellite control room. Computerized control system data showed that the overhead reflux pump was started at 1:17:14 p.m., and that the fuel gas to the furnace was stopped at 1:19:59 p.m.; however, the data showed that the incoming feed to the raffinate splitter was not stopped.

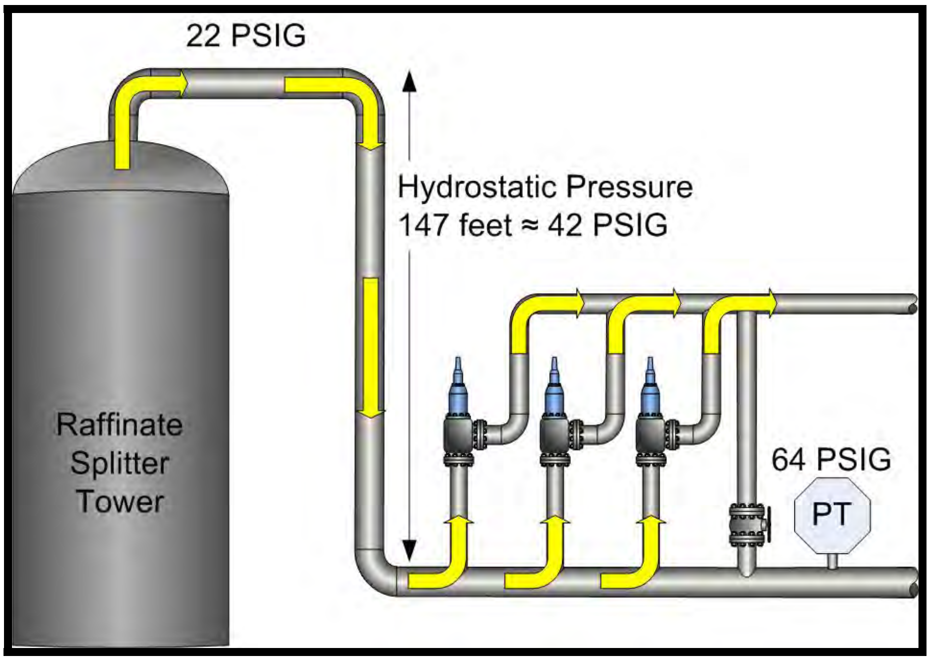

Figure 8. Hydrostatic head of liquid in overhead piping leads to the three relief valves opening

The minimum closing (blowdown) pressure for the three safety relief valves to stop flowing was 37.2 psig (256.5 kPa). Computerized control system data indicate that all three safety relief valves were fully open and flowing at capacity for slightly longer than six minutes. An average pressure of 61 psig (421 kPa) at

[46] Reflux is a part of the product stream that is returned to the process to assist in giving increased conversion or recovery (Parker, 1994).

the inlet to the three safety relief valves maintained the flow. Eventually, the amount of material and pressure in the tower overhead line decreased due to the flow through the valves, the raffinate splitter reflux flow, and the heavy raffinate rundown. This caused the pressure to drop and the safety relief valves to close after an estimated 51,900 gallons (196,500 liters) of flammable liquid flowed from the valves into the collection header (Appendix G.3).

2.5.9 Hydrocarbon Liquid Flows Into Collection Header

The flammable liquid flowed from the overhead vapor line through the safety relief valves into the collection header for 46 seconds then discharged into the blowdown drum[47] (Appendix G.3).

2.5.10 Flammable Liquid Flow Into ISOM Sewer System

As the blowdown drum and stack filled, some of the flammable liquid flowed into the ISOM unit process sewer system through the chained-open 6-inch NPS manual block valve (Figures 3 and 4) and the other safety relief valve discharge pipe headers. As explained in section 2.2.5, this practice of discharging to the sewer was unsafe.

The liquid flow rate from the raffinate splitter to the blowdown drum was calculated to be 509,500 gallons per hour (gph) (1,929,000 lph), resulting in 51,900 gallons (196,500 liters) being released in the six minutes that the safety relief valves were open. The flow rate of liquid hydrocarbons to the sewer through the 6-inch NPS gooseneck pipe varied with the hydrostatic head pressure in the blowdown drum and stack as it filled, but when the blowdown system completely filled with liquid the peak rate was calculated to be 223,400 gph (Appendix G.3).

[47] The safety relief valves on the raffinate splitter were mounted approximately 50 feet (15 m) above ground level; therefore, once the liquid level in the blowdown stack reached an equivalent height and above, the increasing hydrostatic head increased the backpressure in the header, in turn decreasing the flow through the safety relief valves.

From the gooseneck pipe, the flammable liquid flowed into a sewer line and then into West Diversion Box No 2. The high and high-high level alarms for this box were recorded by the computerized control system at 1:16 p.m. and 1:18 p.m., respectively. High and high-high level alarms were also recorded by the computerized control system at the dry weather sewer, which is downstream from West Diversion Box No. 2, at 1:17 p.m. and 1:18 p.m., respectively.

Because the series of pipes from the diversion box to the storm sewer have flow capacities three times the estimated liquid flow from the base of the drum, it is unlikely the sewers backed up in the ISOM unit.

2.5.11 Flammable Liquid Flow Out of the Blowdown Stack

Once the blowdown system filled, flammable liquid discharged to the atmosphere from its stack as a geyser and fell to the ground (Figure 9). Shortly after the ISOM operators began troubleshooting the pressure spike, they received, via radio, the first notification that the blowdown drum was overflowing. In response to the radio message, the Board Operator and Lead Operator used the computerized control system to shut the flow of fuel to the heater, while the other operators left the satellite control room and ran toward an adjacent road, Avenue F, to re-direct traffic away from the blowdown drum, as required by BP’s “Emergency Response Procedure A-7.”

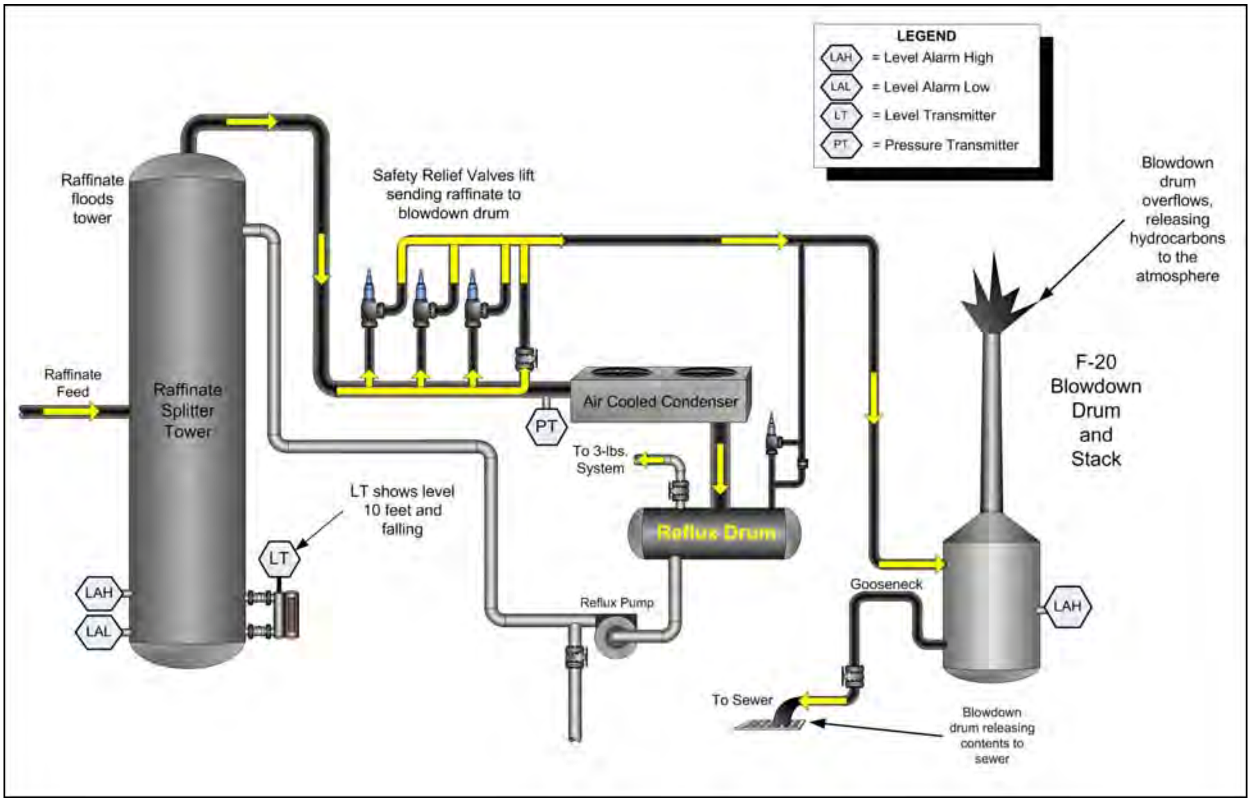

Figure 9. Tower overfills and blowdown drum releases hydrocarbons

The ISOM operators stated they had insufficient time to sound the emergency alarm before the explosion. Approximately 15 seconds after hearing the radio message, both the Board Operator and the Lead Operator said they started the process of shutting off the fuel to the furnace using the computerized control system. Their testimony is substantiated by the computerized control system data, which showed that the fuel gas flow control valve was shut five seconds before the explosion. Hundreds of alarms registered in the computerized control system at 1:20:04 p.m., including the high level alarm on the blowdown drum; the flood of alarms indicates when the explosion occurred. Consequently, ISOM operations personnel did not have sufficient time to assess the situation and sound the emergency warbler alarm prior to the explosion.

Numerous eyewitnesses[48] reported seeing the geyser at the top of the blowdown stack, which they estimated to be approximately 20 feet (6.1 m) high and of a diameter equal to that of the blowdown stack (34 inches or 86 cm).

Post-incident calculations showed that filling the blowdown drum and stack and additional safety relief valve headers took three minutes and 36 seconds; thus, the hydrocarbon liquid reached the top of the blowdown stack four minutes and 22 seconds after the safety relief valves started to flow. The hydrocarbon liquid flow rate out of the blowdown stack to the atmosphere was calculated to be 257,300 gph, meaning that 7,600 gallons (28,700 liters) were released in the 107 seconds of flow before the relief valves closed (Appendix G.3).

2.5.12 Flammable Vapor Cloud Formation and Fire

The liquid hydrocarbon release time was calculated using computerized control system datapoints and the flow times from DIERS modeling (Appendix H). The flammable vapor cloud reached a wide area, as is clearly evident by the burned area shown in a post-explosion photo (Figure 10).

The burned area is estimated to be approximately 200,000 square feet (18, 581 m2). Two mechanisms explain how the vapor cloud covered an area this size in such a short interval: the first was direct dispersion from evaporation prior to ignition that was responsible for the bulk of the dispersal, and the second was “pushing” of flammable vapors as subsonic flames burned through the flammable cloud. The hydrocarbon liquid cascading down the stack and blowdown drum coupled with the impact of the falling liquid onto process equipment, structural components, and piping, promoted fragmentation into relatively small droplets, thereby enhancing evaporation and the formation of the flammable vapor cloud (Appendix H.15).

[48] The CSB interviewed more than 25 people, a combination of BP and contractor employees, who were injured by or observed the vapor cloud explosion.

Atmospheric wind also helped push the vapors and small droplets downwind, causing them to mix with air. The wind direction at the time of the incident was reported to be out of the northwest traveling southeast at 5 miles (8 km) per hour and as Figure 10 shows, the burned area is elongated in that direction. However, portions of the vapor cloud also went upwind and cross wind (Appendix H.10.1), which placed the trailer area within the flammable cloud covered area.

Figure 10. The darkened areas in and around the ISOM unit had the heaviest fire damage; the red arrow points to the top of the blowdown stack

2.5.13 Ignition Source

Although several potential ignition sources (Appendix H.16) were identified, the most likely ignition point was an idling diesel pickup truck (Figure 11). This truck was parked about 25 feet (7.6 m) from the blowdown drum, and several eyewitnesses reported seeing or hearing the truck's engine over-revving when the vapor cloud reached it.

Figure 11. Idling diesel pickup truck at north end of ISOM unit

Two eyewitnesses saw the truck catch fire, followed shortly by the vapor cloud explosion. One eyewitness saw sparks leaving the truck after a backfire and igniting the vapor cloud. While the diesel pickup has been positively identified by witnesses as an ignition point, this does not preclude the potential that the cloud was additionally ignited by other sources.

2.5.14 Blast Pressure

Once ignited, the flame rapidly spread through the flammable vapor cloud, compressing the gas ahead of it to create a blast pressure wave. Furthermore, the flame accelerated each time a combination of congestion/confinement and flammable mix allowed, greatly intensifying the blast pressure in certain areas. These intense pressure regions, or sub-explosions, produced heavy structural damage locally and left a pattern of structural deformation away from the blast center in all directions. A computer simulation[49] and a blast overpressure map (Figure 12) were developed based on site observations, structural analysis, and blast modeling (Appendix H).

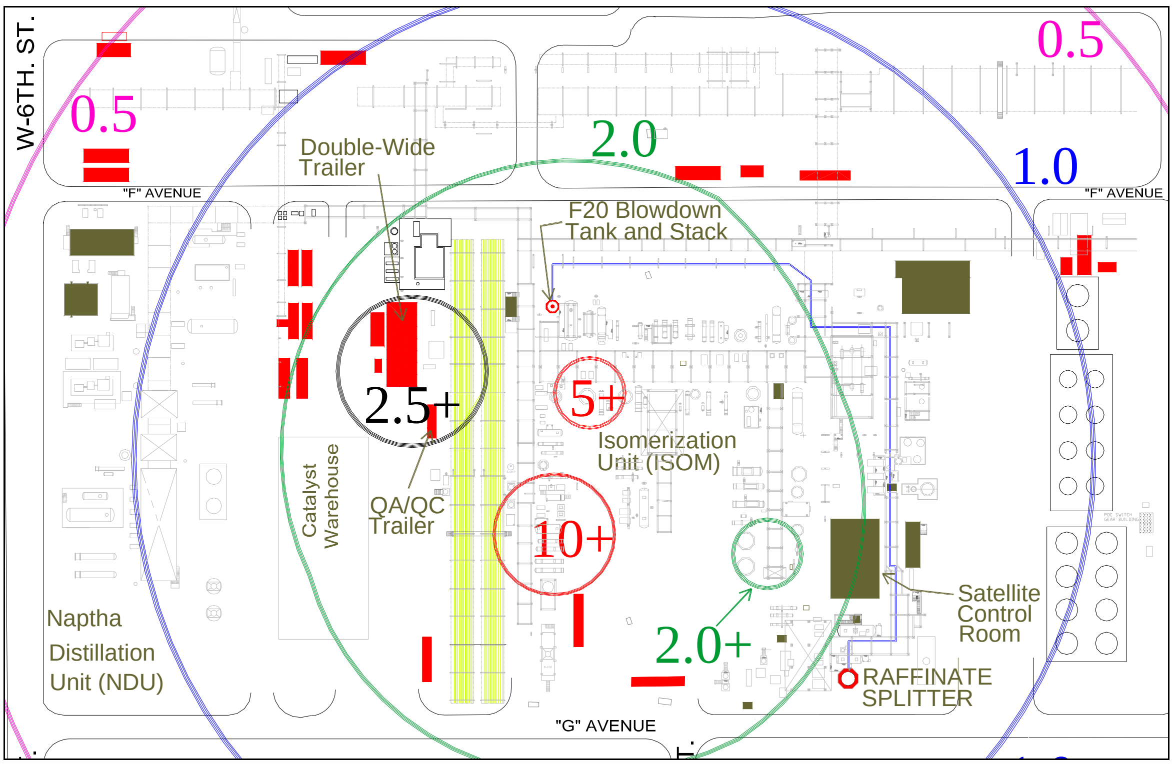

Figure 12. Blast overpressure map depicting the areas of highest blast pressure (10+, 5+, and 2.5+ psi)

2.5.15 Post-Explosion Fires

The flame-front that burned through the vapor cloud also ignited the flammable liquid that had accumulated on the ground near the base of the blowdown drum, resulting in a pool fire. The fire lasted long enough and produced sufficiently high temperatures, in combination with firefighting water spray, to

[49] The computer simulation is available for viewing or downloading from the CSB website, www.csb.gov.

cause the concrete of the pipe rack columns to spall.[50] The CSB learned of several additional fires in and around the ISOM unit based on eyewitness interviews and review of news footage shot from local television station helicopters. (Appendix H-12 provides further details on the pool fire.)

2.5.16 Fatalities and Injuries

In the explosion, 15 contract employees working in or near the trailers sited between the ISOM and the NDU unit were killed. Autopsy reports revealed that the cause of death for all 15 was blunt force trauma, probably resulting from being struck by structural components of the trailers. Three occupants in the Quality Assurance/Quality Control (QA/QC) trailer perished, and 12 of 20 workers inside the double-wide trailer were killed; the others were seriously injured.

A total of 180 workers at the refinery were injured, 66 seriously enough that they had days away from work, restricted work activity, or medical treatment. The majority of these suffered multiple injuries, typically combinations of: fractures, lacerations, punctures, strains, sprains, and/or second- and third-degree burns. Of the seriously injured, 14 were BP employees; the rest were contractor employees from 13 different firms. Of the 114 workers given first aid, 35 were BP employees; 79 were contract employees from 14 different contracting firms. None of the contract workers in the area surrounding the ISOM were personnel essential to the startup of the unit.

2.5.17 Equipment and Facility Damage

The most severe blast damage occurred within the ISOM unit, from the trailer area to the catalyst warehouse (Figure 13), and the surrounding parking areas. The satellite control room was severely damaged and the catalyst warehouse was destroyed.

[50] Spalling is a breakdown in surface tensile strength of concrete when the concrete is exposed to extreme heat, such as during a fire, and then rapidly cooled, such as by the water used to extinguish the fire. (NFPA, 2004, *Guide for Fire and Explosion Investigations*, NFPA 921, pg. 36).

Many of the approximately 70 vehicles in the vicinity of the ISOM unit were damaged and a number were destroyed. More than 40 trailers were damaged; 13 were destroyed. On June 30, 2006, the CSB released a detailed analysis of the trailer damage, which can be viewed or downloaded from the CSB website, www.csb.gov.

Figure 13. Destroyed trailers west of the blowdown drum (red arrow in upper left of the figure)

Buildings in surrounding units also had blast damage, but of a much lower magnitude. This damage was characterized by broken windows, cracked masonry walls, damaged doors, bent metal panels, and dispersal of interior contents; 50 storage tanks sustained varying degrees of structural damage, even though much of the tank farm was situated more than 250 feet (76 m) from the explosion. Most of the damage sustained by the tanks consisted of buckled tank shells, both the shell sides and the roofs (for those tanks with domed roofs). The explosion also damaged several tanks designed to hold hazardous substances, such as benzene, which allowed benzene vapors to escape.[51]

2.5.18 Offsite Damage

Windows were shattered in homes and businesses located north of the refinery, up to a distance of three-quarters of a mile away from the ISOM unit.

2.5.19 Post-Incident Emergency Response

The emergency response teams made a rapid and effective effort to help the injured and recover the victims. Texas City Industrial Mutual Aid System (IMAS) member companies responded and assisted with fire hose lines and search-and-rescue. None of the emergency response personnel were injured during rescue efforts.

The blast produced a large debris field of damaged trailers and vehicles located between the NDU and ISOM units. To recover victims from this area, the site was necessarily disturbed by the emergency responders. Debris, vehicles, and equipment were moved to initiate search-and-rescue and recover the fatally injured. As operators and emergency responders entered the ISOM unit to isolate the plant, some valve positions were changed, but no records were kept to document these changes. Therefore, there was no record of the actual state of some of the valves at the time of the incident, information that is important when trying to reconstruct the incident and determine its causes.[52]

[51] After the incident, the liquid hydrocarbons containing benzene were pumped from the damaged tanks. On April 1, 2005, the elevated benzene readings in the ISOM area dropped, allowing the CSB investigators to enter the site and inspect the incident area while wearing appropriate personal protective equipment.

[52] The CSB was able to reconstruct some of the valve position changes based on interview accounts.

3.0 SAFETY SYSTEM DEFICIENCIES IN UNIT STARTUP

Although actions or errors by operations personnel at the BP Texas City site, as described in the preceding section, were immediate causes of the March 23 accident, numerous latent conditions and safety system deficiencies at the refinery influenced their actions and contributed to the accident. Addressed here are the human factors[53] that explain why feed was added to the tower for three hours without liquid being removed. While recognizing that human errors were made in the raffinate startup, this investigation goes beyond individual failures to gain a deeper understanding of why the incident occurred, which is more useful in major accident prevention.[54] Renowned process safety expert Trevor Kletz puts it plainly: “To say accidents are due to human failing is like saying falls are due to gravity. It is true but it does not help us prevent them.” The broader aspects of this investigation revealed serious management safety system deficiencies that allowed the operators and supervisors to fail. The following underlying latent conditions contributed to the unsafe start up:

- A work environment that encouraged operations personnel to deviate from procedure.
- Lack of a BP policy or emphasis on effective communication for shift change and hazardous operations (such as unit startup).
- Malfunctioning instrumentation that did not alert operators to the actual conditions of the unit.

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[53] “Human Factors refer to environmental, organizational and job factors, and human and individual characteristics, which influence behaviour at work in a way which can affect health and safety” (HSE, 1999).

[54] The CSB followed accepted investigative practices, such as the CCPS’s *Guidelines for Investigating Chemical Process Accidents* (1992a). Chapter 6 of the CCPS book discusses the analysis of human performance in accident causation: “The failure to follow established procedure behavior on the part of the employee is not a root cause, but instead is a symptom of an underlying root cause”. The CCPS guidance lists many possible “underlying system defects that can result in an employee failing to follow procedure.” The CCPS provides nine examples, which include defects in training, defects in fitness-for-duty management systems, task overload due to ineffective downsizing, and a culture of rewarding speed over quality.

- A poorly designed computerized control system that hindered the ability of operations personnel to determine if the tower was overfilling.
- Ineffective supervisory oversight and technical assistance during unit startup.
- Insufficient staffing to handle board operator workload during the high-risk time of unit startup.
- Lack of a human fatigue-prevention policy.
- Inadequate operator training for abnormal and startup conditions.
- Failure to establish effective safe operating limits.

3.1 Work Environment Encouraged Procedural Deviations

Operators deviated from the raffinate unit startup procedure on March 23, 2005. These deviations were not unique actions committed by an incompetent crew, but were actions operators, as a result of established work practices, frequently took to protect unit equipment and complete the startup in a timely and efficient manner.

Several aspects of the work environment encouraged such deviations. Management did not ensure that the startup procedure was regularly updated, even though the startup process had evolved and changed over time with modifications to the unit's equipment, design, and purpose.[55] The procedure did not address critical events the unit experienced during previous startups, such as dramatic swings in tower liquid level, which could severely damage equipment and delay startup. In addition, specific instructions for unique startup circumstances were not included in the procedure, such as the unusual stopping and resumption of the ISOM startup or the routing of products to different storage tanks. Management had also allowed operators to make procedural changes without performing proper Management of Change

[55] The unit underwent several operational changes, including the de-rating of the splitter tower's three relief valves from 70 psig to 40, 41, and 42 psig, and the switch to flooded drum operation (as discussed in Section 2.2.2) , which were not reflected in the procedures.

(MOC) hazard analysis, thereby encouraging operators to make unplanned (and potentially unsafe) deviations during startup. All of these managerial actions (or inactions) sent a strong message to operations personnel: the procedures were not strict instructions but were outdated documents to be used as guidance.

Operators relied on knowledge of past startup experiences (passed down by the more skilled veteran operators) and developed informal work practices to prevent future startup delays. Indeed, several procedural deviations made by the operations crew on March 23, 2005, were common practices in 18 previous raffinate splitter tower startups (Appendix I).

3.1.1 Procedures Did Not Reflect Actual Practice

Management did not ensure that unit operational problems were corrected over time, leading operators to deviate from established procedures. Historical computer data from five years of ISOM startups highlight past critical events: 1) in a majority of the 19 ISOM startups between April 2000 and March 2005,[56] the tower was filled above the range of the level transmitter despite procedural instruction to fill the tower to a 50 percent reading on the transmitter; 2) operators frequently ran the valve sending liquid raffinate out of the unit to storage in "manual" instead of "automatic" control mode, as the procedure required; 3) the tower experienced dramatic swings in liquid level during 18 of the 19 previous startups, making control of the startup difficult for operators, yet the instrumentation and equipment were not reviewed nor were methods for handling swings in liquid level addressed in the procedure; and 4) tower pressure alarm set-points were frequently exceeded, yet the procedure did not address all the reasons this might happen and the steps operators should take in response.

[56] The 19 startups include the March 23, 2005, startup.

In fact, only one of the 19 ISOM unit startups maintained both the tower level within the range of the level transmitter and the pressure within the alarm limits set for safe tower operation. However, none of the 18 previous startups before March 23, 2005, were considered abnormal or investigated to correct these operational deficiencies or possible equipment problems.

Control board computer records of the last 19 raffinate unit startups show that it was common for the liquid level in the tower to significantly rise and fall during the initial stages of startup. Indeed, in 14 of the 19 startups, the tower experienced significant swings in level; the swings were so severe that in the 14 startups the level alarm went off a total of 74 times.[57] Of the past 19 ISOM startups, each startup experienced three significant swings, on average, in tower level and heavy raffinate flow out of the tower. The level control valve for the splitter tower was often placed in "manual" mode until the tower flow and level fluctuations subsided. (Appendix I provides data on these 19 startups.)

Introducing feed into the unit such that the range of the level transmitter was exceeded and placing the level controls in "manual" mode deviated from the written startup procedure. However, operators knew that these swings in tower liquid level had the potential to significantly damage unit equipment, particularly the furnace, if the level in the tower was lost. Board operators stated that they often filled the tower above the range of the transmitter and put the controls in "manual" to improve their control of the system and reduce the severity of the swings that could result in a loss of level.

Computer records from the control board confirm that overfilling the tower and putting the controls in "manual" mode during startup were common practice. The tower's high level alarm set-point[58] was exceeded 65 times during the last 19 startups, with more than 50 hours of operating time with the high

[57] The level transmitter provided a reading to the Control Room Board Operator regarding how much feed was in the tower. The transmitter could provide a feed level reading of the 170-ft tower only when the level in the tower was inside a 5 foot (1.5 m) span within the bottom 9 feet of the tower.

[58] The high level alarm was set at 72 percent of transmitter output.

level alarm activated. In contrast, the low level alarm[59] was triggered nine times, and the column operated in low alarm for slightly more than five hours during the 19 startups. This evidence supports the conclusion that operators biased the tower level on the high side, likely to avoid the possibility of losing the level and damaging the furnace. This bias of running the tower on the high side occurred in nearly all of the last 19 startups. The operators' actions show that they were aware of the tower's low level risks, but not the high level risks.

Without awareness of the risks of high level, the operators often conducted startup without knowing the actual amount of material in the tower. In 15 of the 19 startups, the liquid level rose beyond the range of the transmitter, and in eight, the tower was operated out of range for more than one hour. Filling the tower beyond the range of the level transmitter (that is, beyond an approximate height of 9 feet from the bottom of the tower) was a departure from the startup procedure, which instructs operators to fill the tower to 50 percent (6.5 feet) in the tower.[60] Once the feed rises above the span of the transmitter, operators have no ready means to determine how much liquid is in the tower and makes overfilling the tower much more likely.

Pressure excursions outside the procedure's stated 32 psig (221 kPa) alarm set-point also occurred in 14 of the 19 startups.[61] Since the beginning of 2003, two startups prior to the March 23 incident had pressures above the relief valve set-points, which likely lifted the relief valves and discharged hydrocarbon vapor to the blowdown drum and stack. Neither of these two startup incidents was investigated.

[59] The low level alarm was set at 35 percent of transmitter output.

[60] At the midpoint (a 50 percent output on the transmitter), the tower is filled to a height of approximately 6.5 feet. According to the procedure, this level is established in the bottom of the tower by putting the level control valve in "automatic" mode to control the flow of bottom tower liquid to storage. After the level is established, the raffinate feed is to be slowly heated, which gradually increases tower pressure.

[61] In nine of the 19, the splitter pressure increased rapidly to over 40 psig.

The computer data for critical events from previous startups was available to the managers, yet engineers and supervisors stated they were unaware of the deviations. Management did not effectively review the available computer records of these deviations and intervene to prevent future deviations. The operational problems should have been corrected and the procedures updated to emphasize the importance of following the written instructions to the operating staff.

When procedures are not updated or do not reflect actual practice, operators and supervisors learn not to rely on procedures for accurate instructions. Other major accident investigations reveal that workers frequently develop work practices to adjust to real conditions not addressed in the formal procedures. Human factors expert James Reason refers to these adjustments as “necessary violations,” where departing from the procedures is necessary to get the job done (Hopkins, 2000). Management’s failure to regularly update the procedures and correct operational problems encouraged this practice: “If there have been so many process changes since the written procedures were last updated that they are no longer correct, workers will create their own unofficial procedures that may not adequately address safety issues” (API 770, 2001).

3.1.2 Procedural Changes Without Management of Change (MOC)

Deviations from the procedure were made without performing MOC hazard analyses. Written operating procedures are used to provide clear instructions for safely operating a process. BP guidelines state that procedures should be reviewed as often as necessary to assure that they reflect current operating practices, are handled according to MOC policy, and are certified annually as being current and accurate.[62]

[62] Amoco Petroleum Performance Sector, “Refining Implementation Guidelines for OSHA 1910.119 and EPA RMP,” Section D-4: Operating Procedures

BP Texas City's MOC policy also asserts that the MOC be used when modifying or revising an existing startup procedure,[63] or when a system is intentionally operated outside the existing safe operating limits.[64] Yet BP management allowed operators and supervisors to alter, edit, add, and remove procedural steps without conducting MOCs to assess risk impact due to these changes. They were allowed to write "not applicable" (N/A) for any step and continue the startup using alternative methods.

Allowing operations personnel to make changes without properly assessing the risks creates a dangerous work environment where procedures are not perceived as strict instructions and procedural "work-arounds" are accepted as being normal. API 770 (2001) states: "Once discrepancies [in procedures] are tolerated, individual workers have to use their own judgment to decide what tasks are necessary and/or acceptable. Eventually, someone's action or omission will violate the system tolerances and result in a serious accident." Indeed, this is what happened on March 23, 2005, when the tower was filled above the range of the level transmitter, pressure excursions were considered normal startup events, and the control valves were placed in "manual" mode instead of the "automatic" control position.

3.1.3 Startup Procedure Lacked Sufficient Instructions

The ISOM raffinate section startup procedure lacked sufficient instructions for the Board Operator to safely and successfully start up the unit. The procedure instructed the Board Operator to open the valve that would send heavy raffinate liquid out of the unit to storage, but did not explain the safety implication of this deviation. The procedure did not instruct the Board Operator to pay close attention to the incoming/outgoing liquid raffinate flow readings or to calculate a material balance[65] of the unit during startup, nor did it explain how to make such a calculation. Calculating material balance for a unit is a

[63] "Texas City Process Safety Guideline No. 10: Management of Change," from the *BP Amoco Texas City Process Safety Guidelines Manual,* last revised 8/4/99

[64] Ibid.

[65] A material balance calculation relies on knowledge of the flow rates into and out of a piece of equipment, such as a tower, and the board operator's understanding of how the net rate affects accumulation of liquid within the equipment over time.

method used by operations personnel during times of potential flow imbalances or level uncertainty; that is, when the amount of material coming into the unit does not necessarily equate to the material being removed from the unit. Start up of a unit is a time when material balances should be calculated.

Good practice guidance from Center for Chemical Process Safety (CCPS) on writing effective procedures states: "When procedures require calculations, the calculations must be clear and understandable…. Having the calculation in the procedure or readily available ensures accuracy and consistency" (CCPS, 1996a).

The procedure also did not include instructions on halting unit operations in the middle of the startup process, as was done during the early morning hours on March 23, 2005, nor did it provide instruction for recommencing startup several hours later by a different operating crew. The hazards and safety implications of a partial startup/shutdown/re-startup were not addressed and specific steps to initiate such activities were not provided.

BP's raffinate startup procedure included a step to determine and ensure adequate staffing for the startup; however, "adequate" was not defined in the procedure. An ISOM trainee checked off this step, but no analysis or discussion of staffing was performed.[66] Despite these deficiencies, Texas City managers certified the procedures annually as up-to-date and complete.

3.1.4 Summary

Post-incident, BP emphasized that following the procedures would have prevented the explosions and fire on March 23 ("Fatal Accident Investigation Report," 2005). However, Texas City management did not emphasize the importance of following procedures as evidenced by its lack of enforcement of the MOC

[66] The Trainee acknowledged that he followed orders of his trainer and signed off on numerous startup tasks without knowing whether the tasks were completed. The CSB has not located evidence to suggest that such a discussion or analysis was conducted for the March 23, 2005, startup.

policy, its acceptance of procedural deviations during past startups, and its failure to ensure that the procedures remained up-to-date and accurate. [67]

3.2 Ineffective and Insufficient Communication Among Operations Personnel

Two critical miscommunications occurred among operations personnel on March 23, 2005, that led to the delay in sending liquid raffinate to storage: 1) the instructions for routing raffinate products to storage tanks were not communicated from Texas City management and supervisors to operators; and 2) the condition of the unit – specifically, the degree to which the unit was filled with liquid raffinate – was not clearly communicated from night shift to day shift.[68] These lapses in communication were the result of BP management's lack of emphasis on the importance of communication. BP had no policy for effective shift communication,[69] nor did it enforce formal shift turnover or require logbook/procedural records to ensure communication was clearly and appropriately disseminated among operating crews.[70]

[67] Indeed, one of the opening statements of the raffinate startup procedures asserts "This procedure is prepared as a guide for the safe and efficient startup of the Raffinate unit." This statement is at fundamental odds with the OSHA PSM Standard, 29 CFR 1910.119, which states that procedures are required instructions, not optional guidance.

[68] Miscommunication occurred regarding startup of the unit altogether. During a shift directors' meeting on the morning of the incident, the state of the ISOM unit was discussed. Day Supervisor B was told that he would not be able to startup because the storage tanks that received raffinate from the splitter tower were believed to be full. The Shift Director said that the meeting ended with the understanding that the raffinate section would not be started up.

[69] BP Texas City's Learning & Development Services department produced a training document, "Safe Ups and Downs for Refinery and Chemical Units" which states: "The importance of communications between shifts and between individuals must be emphasized [during startup]. Each shift must clearly understand what has been done on prior shifts and what is expected of it. Some overlap of supervisor between shifts can improve communications and continuity of work" (p.24). This good advice was not enforced through plant procedures or practice, nor was additional (experienced) supervision made available during startup.

[70] BP's Grangemouth refinery in the U.K. conducted a study to assess shift turnover communication at its facility and, as a result, created a policy to improve operation staff communication (Appendix J). BP Texas City management did not appear to learn from the lessons of the Grangemouth study.

Inadequate verbal instructions among Texas City supervision and operating personnel regarding critical aspects of ISOM unit startup led to the initial closing of the valve that routes heavy raffinate to storage. A crucial face-to-face discussion between the operator who began the process of starting up the raffinate unit, and the operator who finished the job did not occur at shift change.[71] Further, the night shift's written communication in the unit logbook was minimal and unclear,[72] hindering the Board Operator's ability to accurately understand the specific procedural steps performed during the previous shift and the procedural steps remaining.

On the morning of the incident, feed routing instructions were not written down in either the logbook or the startup procedures. Instead, they were given to the Board Operator over the phone and radio by a Lead Operator who, while having the experience and knowledge to start up the unit, was responsible for other outside operator tasks that took his attention away from helping the Board Operator start up the raffinate section of the ISOM. Based on interview testimony, the verbal communication between the operators was rushed and vague. The Board Operator believed he was told not to send heavy liquid raffinate to tankage because the tanks were full; the Lead Operator believed he communicated that the light raffinate feed was not to be sent to normal tankage, but combined with heavy raffinate flow to storage because the light raffinate tanks were full. Based on logbooks from the tank farm area, the heavy raffinate tank was filling up[73] prior to raffinate unit startup, supporting the fact that a miscommunication occurred.

Communication is most effective when it includes multiple methods (both oral and written); allows for feedback; and is emphasized by the company as integral to the safe running of the units (Lardner, 1996). (Appendix J provides research on effective communication.) During times of abnormal operating

[71] A night outside operator performed initial board operator startup activities in the satellite control room, away from the central AU2/ISOM/NUD control room; this operator filled the tower to 99.9 percent of the range of the level transmitter.

[72] The logbook entry from the night shift stated: "ISOM: Packed raff with raff." The term "pack" is jargon used in the refinery; to "pack" a piece of equipment is to fill it with product; in this case, with liquid raffinate feedstock.

conditions, such as unit startup, the risk of operators having dissimilar understandings of the state of the process unit is even greater (Lardner, 1996).

Effective communication is accomplished by clearly defining roles and responsibilities regarding communication for every employee, and establishing a communication protocol among key operating positions, particularly during shift changes.

3.3 Malfunctioning Instrumentation

The Board Operator’s decision-making was influenced by incorrectly calibrated instrumentation on the raffinate splitter tower (Section 7.0). Accurate instrument readings of process conditions, such as product level, are critical during unit startup, as they provide the operator with a way to monitor the process and help the operator detect system irregularities. When instrumentation provides false or misleading information, accidents are likely.[74]

During the March 23, 2005, startup, the level transmitter indicated that the liquid level in the splitter tower was gradually declining, although it was actually rising.[75] At 1:04 p.m. (approximately 16 minutes before the explosions), the level indicator read 78 percent (a height of about 7.9 feet or 2.41 m) in the tower); however, the tower level was actually at 158 feet (48.16 m). Operations personnel involved in the raffinate section startup were unaware that the transmitter’s reading was inaccurate.

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[73] The tank farm area logbook from the March 22, 2005, night shift states “*Filling up on RAFF” referring specifically to one of the heavy raffinate storage tanks.

[74] The history of accidents and hazards associated with distillation tower faulty level indication, especially during startup, has been well documented in technical literature. See Kister, 1990. Henry Kister is one of the most notable authorities on distillation tower operation, design, and troubleshooting.

[75] The liquid level read 97 percent when startup was resumed at 9:51 a.m., but dropped to 78 percent by 1:04 p.m.

The Day Board Operator stated that he saw the declining level in the tower over three hours prior to the incident and believed the level was accurate, as he expected that the level would decline as the tower heated up and the system returned to normal operating limits.

The Board Operator's belief that the tower level was accurate was reinforced by the redundant high level alarm's failure to activate.[76] This alarm provided a redundant high level indication should the level transmitter malfunction.[77] However, this alarm's set-point was not known to operations personnel or provided in the procedure, control data, or training materials.[78] The lack of a set-point at which the alarm would sound made recognizing the failure of the alarm less apparent. And because the separate alarm did not sound, the Board Operator believed this confirmed the fact that the level had actually dropped in the tower as liquid raffinate left the tower and circulated to the other unit equipment. He did not verify his conclusion about the decline in tower liquid level with any other operations personnel.

In addition, had the tower level sight glass been clean and functional, it could have provided a visual verification of the actual tower level. However, because it was dirty and unreadable[79] (Section 7.1) the tower liquid level could not be visually verified and compared against the level transmitter reading. The Board Operator truly had no functional and accurate measure of tower level on March 23, 2005.

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[76] Control system alarms alert operators of abnormal process conditions via illuminated displays and audible devices on the computerized control system workstation monitors.

[77] The splitter tower had two alarms associated with the level transmitter. A high level alarm set at 72 percent was activated for the entire period of the startup. This alarm was expected to sound, as operators purposely filled the tower above the range of the level transmitter during startup (see section 4.1). The Board Operator said that he remembered seeing this alarm acknowledged when he came on shift; it was acknowledged during the night shift prior to his arrival.

[78] Post-incident calculations determined that the redundant high level alarm was set at 78 percent or approximately 8 feet high in the tower; had it worked during the startup, it would have sounded during the night shift when the operator filled the tower to 99.9 percent of the transmitter's span.

[79] Post-incident testing confirmed that the sight glass was dirty and unreadable at the time of the incident. This instrument had a history of being dirty and non-functional.

3.4 Poor Computerized Control Board Display

The AU2/ISOM/NDU complex is monitored and controlled via a computerized control system[80] in a central control room in the AU2 unit. (Appendix K provides a full description of the complex's system.) The Board Operator – far removed from the physical location of the process unit undergoing startup[81] – depended on the system to provide him with crucial process information, which requires a well-designed control board. On the day of the incident, however, the computerized control system display provided neither flow data in and out of the raffinate unit on the same display screen, nor a material balance calculation, hindering the Board Operator's ability to recognize the need to send liquid raffinate to storage.

To prevent flooding the tower, liquid raffinate entering the process would have to be balanced with the products leaving the unit.[82] The computerized control system screen that provided the reading of how much liquid raffinate was entering the unit was on a different screen from the one showing how much raffinate product was leaving the unit (Figure 14). Having the two feed readings on separate screen pages diminishes the visibility and importance of monitoring liquid raffinate in versus out, and fails to make the imbalance between the two flow readings obvious.

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[80] A computerized control system, often referred to as a DCS or distributed control system, is a data tracking-and-control system that provides operations staff a visual and auditory account of the state of the process unit(s) and allows operators to alter the unit's state by manipulating the system's controls (keyboard, mouse, and touch screens).

[81] Based on a process and instrumentation diagram of the West plant, the centralized control room was approximately 500 feet (152.4 m) from the east side of the ISOM unit.

[82] A material balance calculation is used to determine how much total liquid is in a given unit; it is determined by comparing the amount of incoming feed to the amount of outgoing product, and requires knowledge of how much liquid the total system needs to maintain and run the process smoothly.

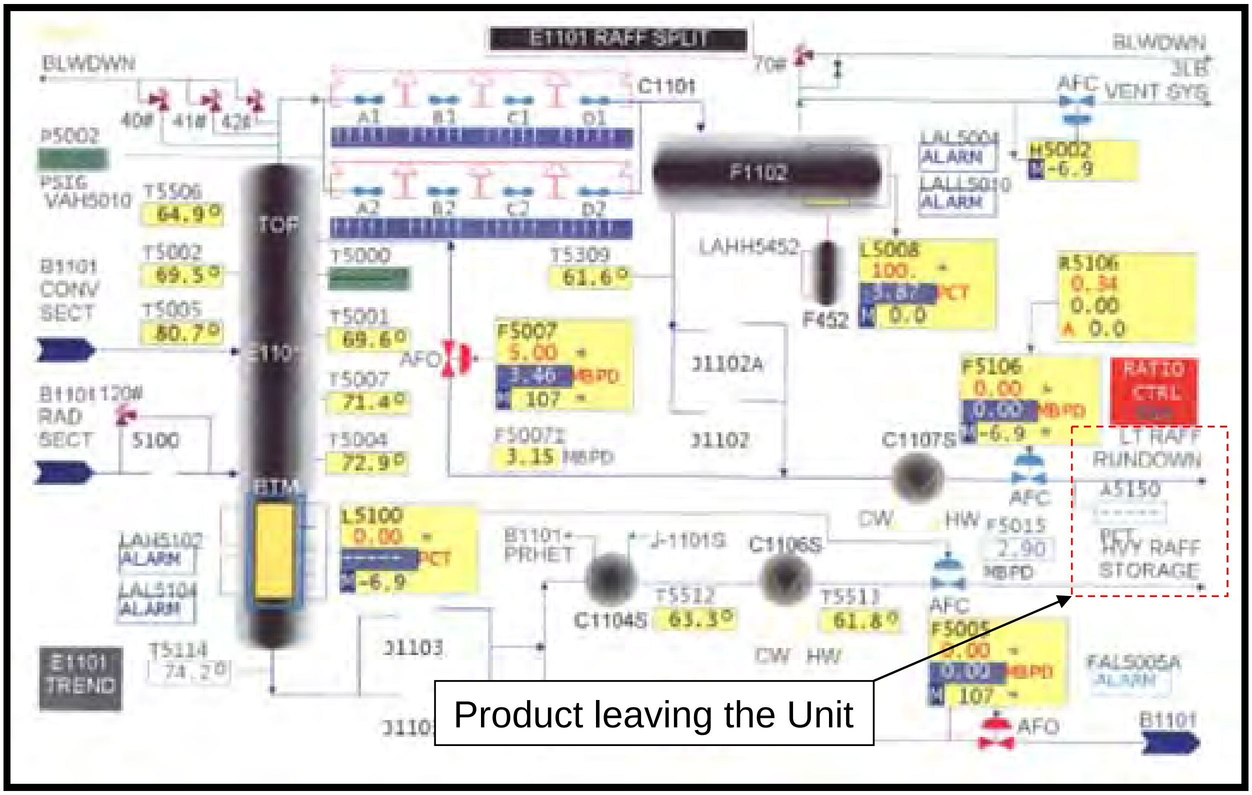

Figure 14. The Board Operator viewed this screen, which provides information on raffinate product leaving the unit but not the liquid being added to the unit.

A poorly designed computerized control system display was found to be a cause in another major incident, the 1994 explosions and fire at a Texaco plant in Milford Haven, in the United Kingdom. The control system did not calculate the material balance of the system and the operators did not know how to make such calculations. The computerized control system was also configured to display only portions of the unit in discrete detailed sections, and did not allow for a complete overview of the process, just like the control system screens for the Texas City ISOM unit. The U.K. Health and Safety Executive[83] recommended that computerized control systems include a process overview and, as appropriate, material balance summaries to ensure full process oversight by operators (HSE, 1997).

[83] The Health and Safety Executive is Great Britain's enforcement authority (in conjunction with local governments) for the Health and Safety Commission, a governing body that is responsible for the regulation of health and safety in the workplace.

3.5 Ineffective Supervisory Oversight and Technical Assistance During Unit Startup

The ISOM/AU2/NDU complex lacked effective supervisory oversight during the startup of the raffinate unit. When Day Supervisor A left the refinery for a family medical emergency, [84] no technically trained personnel with ISOM unit experience were assigned to assist and supervise the Board Operator. Two significant staffing issues arose: it was unclear who was responsible for ISOM unit supervision once Day Supervisor A left, and the one individual available to provide such supervision lacked technical knowledge of the unit. Had the second Day Supervisor on shift (Supervisor B) left his work at the ARU to assist in the raffinate startup, his presence in the control room would likely not have been helpful, as he had little technical expertise on the unit.[85] The two Process Technicians (PTs) who had ISOM knowledge and experience were not assigned to assist with the startup.[86]

Amoco's process safety guideline, "Supervisory Personnel – Startups and Shutdowns," adopted by BP, states that times of unit startup and shutdown are often unpredictable and much more likely than normal operations to go awry. For this reason, the BP guideline states: "Experienced operating personnel should be assigned to each process unit as it is being started up and as it is being shut down."[87] Examples of such personnel who could provide supplementary assistance include supervisors and operating specialists. BP unit management also concluded that supervisory assistance would be needed during unit startups in a

[84] The Day Supervisor had to attend to a family medical emergency.

[85] The second Day Supervisor joined the AU2/ISOM/NDU complex after 25 years at the BP Texas City chemical plant. According to BP South Houston Process Safety Management standard "Training for Process Safety" (SH-PSM_5)," unit supervisors were required only to have an *awareness* of startup procedures and safe operating limits. This type of training is documented but does not require verification.

[86] The two PTs knowledgeable in both the board and outside operator job duties were assigned temporary positions at the ARU where they were paid more to participate in those turnaround activities.

[87] The Amoco Petroleum Products Process Safety Guideline No. 4, "Supervisory Personnel – Startups and Shutdowns," last revision 12/18/97, continues: "For all critical phases of start-ups and shutdowns, technically trained personnel knowledgeable in the process should be readily available."

MOC analysis conducted in 2001.[88] However, on March 23, 2005, Texas City management did not ensure that such personnel were assigned to the startup.

3.6 Insufficient Staffing During Start Up

On March 23, 2005, the ISOM unit was understaffed for the task of unit startup. One board operator was in charge of monitoring and controlling the NDU, AU2, and ISOM units, which under normal conditions, would take about 10.5 hours of a 12-hour shift to run,[89] if all units would be running at a steady state (normal), according to a BP assessment. On the morning of the incident, however, the Board Operator was also responsible for managing the startup of the ISOM raffinate section.[90] A startup is an abnormal unit condition that requires significantly more manual control of a process, as well as critical thinking and decision-making that goes beyond normal unit operation.

Human factors experts have compared operator activities during routine and non-routine conditions and concluded that in an automated plant, workload increases with abnormal conditions such as startups and upsets. For example, one study found that workload more than doubled during upset conditions (Reason, 1997 quoting Connelly, 1997). Startup and upset conditions significantly increased the ISOM Board Operator's workload on March 23, 2005, which was already nearly full with routine duties, according to BP's own assessment.

The Day Board Operator had little assistance for the startup and upset conditions at the control board on March 23, 2005. During the mid-morning hours, the Day Supervisor for the unit left the refinery and no

[88] The MOC's action item stated: "Consider revising the planned startup and planned shutdown procedures to require an asset supervisor be assigned to shift." This action item had a target resolution date of 12/21/01; it remains open.

[89] Hours/shift of steady-state operations was calculated by the BP assessment team via direct observation: the number of observable tasks was listed and the following equation was used: ∑(time/task)/Observation time = percent activity, plus 0.5 (or up to 1.0) minute for the time between each task.

[90] During the day shift on March 23, 2006, the NDU and the AU2 units were running fully and part of the ISOM unit was in circulation.

substitute personnel with ISOM experience replaced him. The Lead Operator – who had board operator experience but was assigned as an outside operator – was involved in organizing contractor work and training two new operators. The other ISOM operators with experience in control board operation during unit startup (the PTs) were at the ARU unit finishing startup activities.

In the years preceding the incident, the concern about insufficient staffing had been raised numerous times (Appendix L). In 2001, a MOC analysis was conducted when the NDU was built and its board responsibilities were added to those of the AU2/ISOM board operator. An action item stated: "Extend the requirement to have two board operators for any planned startup or planned shutdown activities to include NDU." Even though the MOC analysis required two Board Operators for any startup, Texas City management did not implement this recommendation for startups of the raffinate section of the ISOM unit. Instead, a second board operator was brought in only during specific times during ISOM startup.[91]

This was not the first time that operations personnel recognized the need for two board operators during startup and shutdown. A 1996 Amoco staffing assessment of all units in the refinery stated: "Personnel are concerned that under a minimum staffing scenario they would be unable to manage historic upsets." Then in 1999, a MOC for the consolidation of AU2 and ISOM resulted in a recommendation to revise the ISOM planned startup and shutdown procedures to require that an additional independent/dedicated board operator be present to help with critical transitions during times of unit startup and shutdown.[92] Five months prior to the incident, an experienced ISOM supervisor expressed concern to Operations Management that two board operators were needed to safety operate all three units, particularly during

[91] ISOM startup procedure SOP 101.0 specifies that a second board operator shall be brought in only during certain activities, such as when another unit in the complex is being startup up concurrently with the ISOM and when introducing feed into the Penex reactors.

[92] The startup of a highly hazardous process unit has a higher level of risk than normal operations because it requires more manual operation and higher-level critical thinking by the operators, and thus the entire startup process would be considered a critical transition. "Critical transitions" were not defined in the MOC.

times of unit upsets.[93] In January 2005, the Telos safety culture assessment informed BP management that at the production level, plant personnel felt that one major cause of accidents at the Texas City facility was understaffing, and that staffing cuts went beyond what plant personnel considered safe levels for plant operation.

3.6.1 Refining and Corporate Management Decisions Affected Staffing

Despite a history of recommendations and requests for additional staffing during times of unit startup and shutdown, Amoco and BP management cut staffing budgets in the years prior to the March 23, 2005, incident.

In 1994, Amoco reviewed staffing to determine if operations staffing could be adjusted to Solomon performance indices. This review concluded that reducing headcount at Texas City and at the Whiting site in Indiana by the 18 percent necessary to match the Solomon first quartile average would save Amoco between $22 and $33 million in operating expenses. If staffing could be reduced 31 percent, reaching the "Best class Solomon manpower index," the company would save $42 to $61 million. Such changes would result in staffing for normal operations only, where each operations crew is "staffed at a 'lean' level, i.e., no additional personnel on hand to guard against 'peaks' such as safe-offs,[94] absences, and so on."[95] In 1999, BP cut fixed costs nearly 25 percent (see Section 9.4.3), resulting in plant-wide staffing reductions,[96] and combined and consolidated from two to one the board operator positions for the AU2 and ISOM units.

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[93] Email from an AU2/ISOM/NDU Supervisor to Operations personnel and Texas City management, including the Superintendent of the AU2/ISOM/NDU, dated November 11, 2004.

[94] A safe-off is a procedure for emergency shutdown of a process unit in the event of a process, utility, and/or equipment failure.

[95] McKinsey study, November 2, 1994, commissioned for the Amoco Oil Company

[96] The Texas City Business Unit Strategy document, dated October 1999, stated that the budget targets could be accomplished, in part, by reducing staffing by "roughly 15% fewer employees."

Despite these cuts, in a 2004 compliance strategy document, Texas City management stated: "In the face of increasing expectations and costly regulations, we are choosing to rely wherever possible on more people dependant and operational controls rather than preferentially opting for new hardware. This strategy [will place] greater demands on work processes and staff to operate within the shrinking margin for error."[97] Texas City management's cost-cutting resulted in a greater reliance on its operations personnel, specifically the frontline operators, and less on hardware improvements. Yet the company had been significantly reducing the number of these frontline operators since the 1996 Amoco staffing study examined all units for potential staffing cutbacks. And, as section 3.8 discusses, training of the reduced operations personnel was less than adequate.

3.7 Operator Fatigue

On the day of the incident, the Day Board Operator was likely fatigued, experiencing both acute sleep loss[98] and cumulative sleep debt.[99] He had worked 12-hour shifts for 29 consecutive days and generally slept five to six hours per 24-hour period, although he reported feeling most rested with seven hours of sleep per night. The Night Lead Operator, who filled the tower from the satellite control room, worked 33 consecutive days, from February 18–March 23, 2005. The Day Lead Operator – who was training two new operators, dealing with contractors, and working to get a replacement part to finish the ISOM turnaround work – had been on duty for 37 consecutive days, from February 14 until March 23, 2005. Finally, another experienced outside operator, who was helping the Day Lead Operator, worked 31 consecutive days, February 21–March 23, 2005. All of these individuals were working 12-hour shifts.

[97] The Compliance Strategy document was part of a collection of Texas City documents presented to the Global Chief Executive for Refining and Marketing in July 2004 as the strategy adopted at the Texas City refinery.

[98] Acute sleep loss is the amount of sleep lost from an individual's normal sleep requirements in a 24-hour period.

[99] Cumulative sleep debt is the total amount of lost sleep over several 24-hour periods. If a person who normally needs 8 hours of sleep a night to feel refreshed gets only 6 hours of sleep for five straight days, this person has a sleep debt of 10 hours.

Based on an analysis of this information (see below), operator fatigue likely contributed to the incident by impairing operator performance.

Fatigue can increase errors, delay responses, and cloud decision-making (Rogers et al., 1999; HSE, 2005). Research also shows that complex task decision-making that requires innovative, flexible thinking and planning are sensitive to fatigue (Rogers et al., 1999; Rosekind, et al., 1996) (Appendix M).

Based on their work schedules, many of the ISOM operators were likely fatigued; however, this analysis focused on the Day Board Operator because he had a primary role on the day of the incident.

The investigation focused on two questions: 1) Were identifiable fatigue factors[100] present at the time of the incident?; and 2) If yes, did fatigue-related performance loss contribute to or cause the accident? The CSB used a methodology employed by the NASA Fatigue Countermeasures Program and the National Transportation Safety Board (NTSB) to assess operator fatigue in accidents.[101] Using this methodology and evidence from the incident, the CSB concluded that fatigue was a likely contributing factor.

3.7.1 Fatigue Factors

Identifiable fatigue factors were present at the time of the incident. On March 23, 2005, the Day Board Operator had been working 12-hour shifts, seven days a week, for 29 consecutive days.[102] The operator's commute to and from work took between 30 and 45 minutes each way, providing him 10.5-11 hours off from work each day. The operator spent this time with his wife and children, and used it to take care of family duties, household chores, and errands. Some of this time was also needed for meals and to prepare

[100] Fatigue factors are physiological aspects of an individual's sleep/wake cycle that underlie fatigue. Two core fatigue factors are 1) acute sleep loss and cumulative sleep debt; and 2) continuous hours of wakefulness. (Rosekind et al., 1993).

[101] This methodology has been used in NTSB investigations of pipeline board operators and in transportation incidents. As the tasks of board operators, pilots, and drivers parallel each other in that they all deal with issues of critical decision-making, attending to/monitoring partially automated systems, reacting quickly to abnormal conditions, and rectifying deviations from normal conditions, the CSB used this methodology in its investigation.

[102] According to company records, his last day off from work was February 21, 2005, 30 days prior to the incident.

for bed at night and work the next day. He reported that, due to these factors, he routinely got five to six hours of sleep per night, about 1.5 hours less than he slept during his normal work schedule. Losing 1.5 hours of sleep in a 24-hour period for 29 straight days, the Board Operator had accumulated a sleep debt of 43.5 hours.[103] Without any days off from work during that period, the Board Operator had little opportunity to reduce that sleep debt and minimize the effects of chronic sleep loss. Research suggests that even short breaks from work tasks can often lessen the severity of accumulated fatigue (Rosekind et al., 1996). However, the Board Operator also reported that he rarely took official/scheduled rest breaks during his shift and ate meals in front of the board.

The work-sleep schedule of the Day Board Operator highly suggests fatigue, and the other operators of the unit were also likely experiencing the effects of fatigue. According to the Baker Panel findings, the average rate of overtime for operators and maintenance personnel at the Texas City refinery in the past four years was 27 percent, with several employees exceeding 68 percent (Baker et al., 2007). The Baker Panel Report concluded that such overtime rates were excessive, would likely compromise safety, and were symptomatic of understaffing (Baker et al., 2007).

3.7.2 Operator Performance Impaired by Fatigue

Evidence suggests that the operators' fatigue degraded their judgment and problem-solving skills, hindering their ability to determine that the tower was overfilling.

3.7.2.1 Fatigue Impaired Judgment and Decision-Making

The Board Operator, as well as the outside operators, did not recognize that feed was entering the tower but not being removed from the unit for three hours, that the tower was overfilling, or that the consequences of the tower flooding might be catastrophic. Throughout the startup on March 23, 2005, the

[103] If he was getting 5.5 hours of sleep per night, he was suffering from an acute sleep loss of 1.5 hours/night. 1.5(29 days) = sleep debt of 43.5 hours (about a month and a half of lost sleep).

operations personnel did not make the connection between adding feed to the unit and the risk of explosions and fire.

It is common for a person experiencing fatigue to be more rigid in thinking, have greater difficulty responding to changing or abnormal circumstances, and take longer to reason correctly (Rogers et al., 1999).

3.7.2.2 Fatigue Contributed to Cognitive Fixation

In the hours preceding the incident, the tower experienced multiple pressure spikes. In each instance, operators focused on reducing pressure: they tried to relieve pressure, but did not effectively question *why* the pressure spikes were occurring. They were fixated on the symptom of the problem, not the underlying cause and, therefore, did not diagnose the real problem (tower overfill). The absent ISOM-experienced Supervisor A called into the unit slightly after 1 p.m. to check on the progress of the startup, but focused on the symptom of the problem and suggested opening a bypass valve to the blowdown drum to relieve pressure. Tower overfill or feed-routing concerns were not discussed during this troubleshooting communication. Focused attention on an item or action to the exclusion of other critical information – often referred to as cognitive fixation or cognitive tunnel vision – is a typical performance effect of fatigue (Rosekind et al., 1993).

3.7.3 Lack of a BP Fatigue Prevention Policy

BP has no corporate or site-specific fatigue prevention policy or regulations. The contract between the United Steelworkers Union and BP provides a minimum number of hours per work week requirement, but not a maximum.[104] According to BP, "operators were expected to work" the 12-hour, 7-days-a-week turnaround schedule, although they were allowed time off if they had scheduled vacation , used personal/vacation time, or had extenuating circumstances that would be considered on a "case-by-case" basis.[105]

OSHA, the API, the NPRA, or others have no regulations or industry safety guidelines on fatigue prevention that applies to the chemical process industry or oil refinery workers. However, regulations do exist for a variety of other industries, such as the nuclear sector, aviation, and motor carriers. Some European countries have also begun to regulate employee fatigue (Appendix N).

The NTSB has also recognized the effect of fatigue on job performance and has included, in its "Most Wanted Safety Improvements," a recommendation to the U.S. Department of Transportation for employee working hour limits in all modes of transportation to prevent accidents and incidents caused by human fatigue.[106]

Companies involved in high-hazard processes must establish a shift work policy to minimize the effects of fatigue, especially because individuals are poor self-assessors and are less likely to admit they are too fatigued to work safely. The shift work policy should aim to manage both normal shift patterns/rotations

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[104] In March 1999, ISOM operators, including the Day Board Operator, attended a training course, "Are You Alert Through Your Shift?"; however, BP was unable to provide the course materials to the CSB because the document's retention period expired. According to BP, documents are no longer considered "active" if they are not "referenced on a regular basis, generally more than once each month or during the current fiscal year." The March 1999 date was the only recorded time the ISOM operators on duty on March 23, 2005, took a course on workplace fatigue.

[105] BP response to CSB interrogatory request for information, December 15, 2006.

[106] http://www.ntsb.gov/recs/mostwanted/intermodal_issues.htm.

and temporary situations, such as turnarounds, by limiting the number of working hours per 24-hour period and the number of consecutive days at work.

The Day Board Operator, and the entire operations crew working the turnaround schedule, was likely experiencing significant effects of fatigue on March 23, 2005. By degrading judgment and causing cognitive fixation, fatigue likely contributed to the overfilling of the raffinate splitter tower.

3.8 Inadequate Operator Training

Inadequate training for operations personnel, particularly for the board operator position, contributed to causing the incident. The hazards of unit startup, including tower overfill scenarios, were not adequately covered in operator training.

BP Board Operator Training consisted of new-hire basic operator training; a two-day generic troubleshooting course; computer-based tutorials; and on-the-job training. (Appendix O provides a more detailed description of the Board Operator's training.)

The ISOM unit operator training program did not include

- training for abnormal situation management, the importance of material balance calculations, and how to avoid high liquid level in towers;
- effective verification methods of operator knowledge and qualifications; and
- a formal program for operations crews to discuss potentially hazardous conditions, such as startup or shutdown, to enhance operator knowledge and define roles.

3.8.1 Training for Abnormal Situation Management

Operator training for abnormal situations was insufficient. Much of the training consisted of on-the-job instruction, which covered primarily daily, routine duties. With this type of training, startup or shutdown procedures would be reviewed only if the trainee happened to be scheduled for training at the time the unit was undergoing such an operation. BP’s computerized tutorials provided factual and often narrowly focused information, such as which alarm corresponded to which piece of equipment or instrumentation. This type of information did not provide operators with knowledge of the process or safe operating limits. While useful for record keeping and employee tracking, BP’s computer-based training often suffered “from an apparent lack of rigor and an inability to adequately assess a worker’s overall knowledge and skill level” (Baker et al., 2007). Neither on-the-job training nor the computerized tutorials effectively provided operators with the knowledge of process safety and abnormal situation management necessary for those responsible for controlling highly hazardous processes. Training that goes beyond fact memorization and answers the question “Why?” for the critical parameters of a process will help develop operator understanding of the unit. This deeper understanding of the process better enables operators to safely handle abnormal situations (Kletz, 2001). The BP Texas City operators did not receive this more in-depth operating education for the raffinate section of the ISOM unit.

According to BP’s training requirements, operators were expected to spend five hours per year reviewing startup and shutdown procedures as part of their normal operating duties. The infrequency of unit startups, in conjunction with the inherently higher risk for accidents during such a time, requires focused and frequent training. Indeed, due to the high-risk associated with such abnormal conditions, the need for training on these infrequent events may be greater than the training needs for normal operation.

BP did not train board operators on the hazards of overfilling towers. The two-day troubleshooting course for board operators did not discuss the consequences of overfilling, and neither the training guides nor the ISOM safe-off[107] procedures provided sufficient guidance on operator response to tower overfilling.

[107] A safe-off is a procedure for emergency shutdown of a process unit in the event of a process, utility, and/or equipment failure.

The BP training program did not include specific instruction on the importance of calculating material balances, and the startup procedures did not discuss how to make such calculations. As a result, the Day Board Operator did not have a full understanding of the material balance for the ISOM unit.

3.8.2 Verifying Operator Knowledge and Qualifications

For several years leading up to the March 23 incident, Texas City managers did not effectively conduct performance appraisals to determine the knowledge level and training development plans of most AU2/ISOM/NDU operators. The refinery-wide 2004 Operator Competency Assurance Model (OCAM) audit[108] results stated that only 25 percent of ISOM unit operators were given performance appraisals annually.[109] The results of the OCAM audits also revealed that zero individual operator development plans were created for ISOM unit operators in 2003 and 2004.

In addition, no Standard Operating Instructions (SOI) existed for the Board Operator position at the time of the March 23, 2005, incident, even though a SOI had been created for the Outside Operator position. The training materials specific to the board operator position were also very limited in scope and detail (Appendix O.1.4).

3.8.3 Simulators Not Used to Train for Hazardous Scenarios

Simulation technology was unavailable to the AU2/ISOM/NDU board operators, despite their reported success in improving employee knowledge at BP's Cherry Point facility (Baker et al., 2007) and the BP chemicals plant adjacent to the Texas City refinery. Gun drills, or verbal discussions of potential

[108] The OCAM audit was a unit assessment of its training program, materials, and appraisal methods, as well as a review of unit records to determine if and how operator performance was being measured and tracked. General audits of the Texas City site were done in 2001 and 2002. Full audits of all refinery units were conducted in 2003 and 2004.

[109] Contrary to the OCAM audit findings, the 2003 and 2004 performance records for the person responsible for conducting/facilitating the operator evaluations reported that 100 percent of the appraisals were completed.

hazardous situations that operators could face while working the unit, were not formally and consistently held for shift crews to develop operator understanding of the ISOM unit's risks.

The need for continual training on hazardous operations was raised multiple times in the years leading up to the incident. The 2001 MOC for adding NDU responsibilities to the AU2/ISOM board operator position resulted in an action item to develop a simulator for the board operator position or an effective gun drill[110] program that would test operator understanding of the units. However, the OCAM audit in both 2003 and 2004 found no evidence that a gun drill program was in effect, even though the MOC documentation incorrectly stated that a gun drill program had been developed.[111] Only one gun drill is listed in the Board Operator's training records and it was conducted on May 9, 2004; no records besides a list of those who attended have been maintained by the company.

Texas City management did not incorporate simulators in its training program, despite ISOM incident investigation recommendations[112] that urged their use to ensure that operators develop the critical decision-making skills necessary for running hazardous chemical processing units. Beginning in 2000, BP's Learning & Development (L&D) department had also pressed site management to equip units with simulators, but was unsuccessful. After the March 2005 incident, the head of L&D department stated that lack of funding was why simulators were not being incorporated into the operator training program: "Big push back has always been initial cost and people/resources/cost to keep current. We could have equipped

[110] A gun drill is a verbal discussion by operations and supervisory staff on how to respond to abnormal or hazardous activities and the responsibilities of each individual during such times. A gun drill program – regularly scheduled and recorded gun drills – had been established at other units at the Texas City refinery but not for the AU2/ISOM/NDU complex.

[111] The actual date of action item resolution on the MOC documentation is April 25, 2003, 24 days after the 2003 audit was conducted.

[112] An incident at the FCCU3 unit in the Texas City refinery led to the following Investigation Report recommendation: "consider providing simulator training for all board operating personnel" (FCCU3 Incident Investigation report, dated February 28, 2003).

every process unit across TCR [Texas City Refinery] with several simulators for what the ISOM incident will cost us." [113]

3.8.4 Refinery and Corporate Management Decisions Affected Training

Corporate-level decisions, such as budget and staff reductions, impaired the delivery of training at the Texas City site. Between 1998 and 2004, the budget for the Texas City refinery L&D department was cut in half, from $2.8 to $1.4 million, and its staff was reduced from 28 to eight.[114] At the time of the incident, four PSM positions, which could have assisted with training and gun drills, were also vacant in the West Plant of the refinery (which included the ISOM unit).

To make up for fewer L&D trainers, BP Texas City went to computer-based training for policies, procedures, and process unit lessons. This type of training saved the company money, according to the individual who, at the time of the incident, was head of the L&D: "[computer-based training] was definitely a cost decision…made across the site; we will push computer based training to you as opposed to bringing you the classroom training…it was a business decision to minimize costs."[115] However, operators who require training for abnormal conditions would not benefit from computer-based training that often focuses on memorizing facts, not troubleshooting unusual events.

In 1999, responding to London executives' call to cut fixed costs 25 percent, Texas City refinery management agreed to implement a number of cost-reduction actions that affected training, including:

- reducing/limiting off-shift board operator training;
- renegotiating with the Union to eliminate one hourly training coordinator;

[113] Email from the head of Learning & Development (L&D) department to L&D staff, dated 4/17/2006.

[114] These figures are for all of BP South Houston; Texas City received approximately 60 percent of the allocated budget and personnel during these years.

[115] Interview with the head of BP's Learning & Development department at the time of the March 23, 2005, incident.

- eliminating all non-OSHA required training for the "short term";[116]
- reducing the training plan for outside operators and maintenance crafts; and
- eliminating the central training organization of the refinery.[117]

While the Texas City site's training department's budget and process safety staff were being cut beginning in 1999, corporate BP identified a gap in training at the refinery. A 2003 external audit found that "[t]raining in most areas is not up to the challenge of performance expectations and anticipated turnover."[118]

The OCAM audits also revealed similar inadequacies; in fact, these audits determined that the unit training coordinator for the ISOM/AU2/NDU spent only about 5 percent of his time actually training personnel. Instead of training, his time was spent filling in for the superintendent, working or supporting a turnaround or project, doing extended work on resolving hazard and operability study (HAZOP) action items, scheduling unit personnel, and filling in on shift for another frontline supervisor. The OCAM audits also found that the budget for both 2003 and 2004 allowed only for initial job and OSHA-required refresher training; there was no budget allowance for increasing the competency of current operators.

[116] The duration of "short term" was not disclosed in the document.

[117] The Texas City Business Unit 1999 Cost Reduction Plan Action Items.

[118] The 2003 external GHSER audit, BP South Houston, September 22, 2003.

3.9 Failure to Establish Effective Safe Operating Limits

BP had established safe operating limits for some ISOM process parameters; however, the ISOM operating limits did not include limits for high level in the raffinate splitter tower. The documentation for the operating limits established limits for process indications like pressure, level, and flow; described the effects of deviating from those limits; and listed recovery methods to avoid operating beyond those limits. Upper and lower limits for process parameters and consequences of deviation are necessary for safe plant operation and are required by the OSHA PSM Standard [29 CFR 1910.119 (d)(2)(i)(D) and (E)]. The only operating limit addressed in BP documentation for safe operation of the raffinate splitter tower was high tower pressure, which was incorrectly listed at 70 psig (482.6 kPa).[119] The document did not address a safe operating limit or consequences of deviation for high splitter tower level. Further, none of the three distillation towers in the ISOM unit specified an operating limit for high tower level.

BP had implemented an operating envelope program designed to increase oversight over process operations and critical parameters, which addressed both safety, environmental, and economic operating limits. Refinery management cited the program in safety assurance reports to BP Group managers as an important way to control operational risks. The operating envelope program data, including information indicating when unit operation occurred outside the limits, were stored electronically and were accessible to the board operator, supervisors, and other personnel on the refinery computer network. The program was intended to capture the frequency and duration of operating limit deviations so that management could oversee how the plant was operating and implement needed corrective action.

Operating beyond the “not to exceed” limits set in the envelope was intended to trigger an incident report or a MOC process if the activity was repeated or prolonged. However, the operating envelope’s

[119] The ISOM Safe Operating Limit document had not been updated to correct the tower pressure limit since the maximum allowable operating pressure was lowered to 40 psig in 2003.

computerized reporting mechanisms to operations managers were not operational because the program's reporting feature was never activated.

In addition, the operating envelope for the ISOM unit did not address the upper operating limit for the raffinate splitter tower level or other distillation towers in the ISOM; consequently, the frequency or duration of instances of high splitter tower level were not recorded. The history of abnormal raffinate section startups with high tower level rising beyond the range of the transmitter was not captured as a "not to exceed" deviation or reported to operations management by the operating envelope system.

BP's ISOM process documentation did not address the consequences of high tower level or actions to take to recover from operating outside the safe operating limit. Safe operating limit documentation, procedures, and training must address the consequences of deviating from key process parameters such as tower level, and provide information on actions to take to return the process to normal conditions. This information is critical for operators to safely respond to abnormal conditions (CCPS, 1995a).

3.10 Distraction Not a Factor

Phone calls and a safety meeting in the control room on March 23, 2005, were investigated as potential distractions for the Board Operator; however, a review of available evidence suggests that neither issue was a likely distraction. The phone calls into and out of the centralized control room were limited in number and duration during the startup. And the historical control board data does not indicate that the Board Operator's decision-making was affected by the safety meeting. (Appendix P provides a more detailed discussion of both concerns.)

3.11 Summary

Numerous underlying latent conditions collectively influenced the decisions and actions of the operations personnel at the AU2/ISOM/NDU complex. These safety system deficiencies created a workplace ripe for human error to occur.

4.0 INCIDENT INVESTIGATION SYSTEM DEFICIENCIES

The CSB found evidence to document eight serious ISOM blowdown drum incidents from 1994 to 2004; in two, fires occurred. In six, the blowdown system released flammable hydrocarbon vapors that resulted in a vapor cloud at or near ground level that could have resulted in explosions and fires if the vapor cloud had found a source of ignition. In an incident on February 12, 1994, overfilling the 115-foot (35-meter) tall Deisohexanizer (DIH) distillation tower resulted in hydrocarbon vapor being released to the atmosphere from emergency relief valves that opened to the ISOM blowdown system. The incident report noted a large amount of vapor coming out of the blowdown stack, and high flammable atmosphere readings were recorded. Operations personnel shut down the unit and fogged the area with fire monitors until the release was stopped.

In August 2004, pressure relief valves opened in the Ultracracker (ULC) unit, discharging liquid hydrocarbons to the ULC blowdown drum. This discharge filled the blowdown drum and released combustible liquid out the stack. While the high liquid level alarm on the blowdown drum failed to operate, the hydrocarbon detector alarm sounded and fire monitors were sprayed to cool the released liquid and disperse the vapor, and the process unit was shut down.

These incidents were early warnings of the serious hazards of the ISOM and other blowdown systems' design and operational problems. The incidents were not effectively reported or investigated by BP or earlier by Amoco (Appendix Q provides a full listing of relevant incidents at the BP Texas City site.) Only three of the incidents involving the ISOM blowdown drum were investigated.

BP had not implemented an effective incident investigation management system to capture appropriate lessons learned and implement needed changes. Such a system ensures that incidents are recorded in a centralized record keeping system and are available for other safety management system activities such as incident trending and process hazard analysis (PHA). The lack of historical trend data on the ISOM blowdown system incidents prevented BP from applying the lessons learned to conclude that the design of the blowdown system that released flammables to the atmosphere was unsafe, or to understand the serious nature of the problem from the repeated release events.

BP's problems with its incident investigation system were not isolated to the ISOM unit. In the two years before the incident, refinery audits and other reviews indicated larger problems with the Texas City incident investigation system. A 2003 external audit[120] found that "a coordinated, self-monitoring and self-assessment process is not evident throughout the line organization." A 2004 audit[121] graded as "poor" how incident investigation information was analyzed to monitor trends and develop prevention programs.

[120] 2003 GHSER Audit Report, BP South Houston, September 22, 2003.

[121] 2004 GHSER Assessment, Texas City Site, August 2004.

5.0 EQUIPMENT DESIGN

5.1 Hazards of High Tower Level

The hazards of overfilling distillation towers were not well understood by Texas City management and operations personnel; however, overfilling incidents in the process industry have been well-documented. Distillation tower expert Henry Kister (2003) analyzed recent trends in distillation tower malfunctions from 900 case histories, and found that more problems initiate at the tower base than in any other section, with half of the tower base malfunctions involving high liquid level.

Kister (2006a) reports several incidents where the high level led to liquid discharges into the tower overhead equipment. For vessels generally, the U.K. Health and Safety Executive similarly found, in its analysis of 718 loss of containment incidents, that overflow was the second leading cause (Collins & Keely, 2003). In his case history review, Kister concludes that faulty level measurement and control are the primary causes of tower high level events, as seen in this ISOM incident (Kister, 2006a & 1990).

5.2 Previous Tower Overfilling Incidents

The hazards of high tower level were also known from a previous ISOM incident investigation. As section 4.0 discussed, on February 12, 1994, another ISOM distillation tower was overfilled with liquid. The investigation report states that the level indication reached 91 percent and remained there while operators struggled to lower the tower level over a 24- hour period. The tower remained in operation while an undiagnosed blockage in the bottom pumps caused the tower to fill with liquid. Overfilling led three pressure relief valves to open, and large amounts of hydrocarbon vapor were released from the blowdown stack. Like the 1994 tower overfill, the 2005 incident involved filling the raffinate splitter tower for several hours with no flow out of the bottom. In both incidents a malfunctioning level transmitter misled operations personnel about the actual liquid level in the tower.

A high distillation tower level led to a fire and explosion incident reported by the U.K. Health and Safety Executive (1997). In July 1994, at the Texaco Milford Haven refinery, a plant upset resulted in liquid hydrocarbons being pumped into a distillation tower for several hours while liquid flow out of the bottom was shut off. This problem was undiagnosed by operations personnel, as the instruments indicating the outlet valve position, level, and flow out of the tower bottom provided inaccurate information. As a result, the tower over-pressured and caused a release of flammable hydrocarbons when outlet piping from the flare knock-out drum failed. The lessons from this incident were addressed to the U.K. refinery and petrochemical industry, including BP (HSE, 1997). The Health and Safety Executive found that the operators were not provided adequate information on process conditions and that Texaco was not adequately monitoring instrument maintenance and equipment inspection.

5.3 Level Indication Design

None of the instruments that indicated raffinate splitter tower level were working properly on March 23, 2005. The tower level instrumentation consisted of a displacer type level transmitter, a level sight glass, and two redundant level switches (high and low level), both of which failed to trigger alarms on the day of the incident.[122] The tower level transmitter provided faulty readings and the level sight glass was dirty and non-operational. The tower was not equipped with an additional level indication or with pressure indicators that could have warned the board operator about high liquid level.

[122] The low level switch failed to alarm but did not play a role in causing the incident.

Kister concluded from his review of distillation tower malfunctions that reliable level monitoring is important in preventing high level incidents, so much so that facilities should "refrain from proceeding with a startup when a reliable level indication is absent" (Kister, 1990). Redundant level instrumentation extending above the range of the primary column level instruments is valuable for detecting excessive liquid levels (Kister, 2006a). Such instrumentation could include an upper displacement meter, a column bottom pressure transmitter, or a lower column differential pressure transmitter. However, to be effective, safety critical instrumentation, such as column bottom level instruments, must be maintained in a functional and correctly calibrated condition.

After the 2005 raffinate splitter tower incident, BP experienced another distillation tower high level incident at its Whiting, Indiana refinery. On December 13, 2005, during unit startup, a distillation tower overfilled, leading to the filling of a flare knockout drum and liquid flow into the fuel gas system, causing flames to shoot out of two furnace fire boxes. A newly installed level transmitter was found to have failed, leading to overfilling the tower while the tower outlet valve was closed. Other pressure indicators on the tower that could have provided additional information on the high level condition were not working. The BP investigation team recommendations included installing an additional level indicator and repairing the two malfunctioning pressure indicators.

5.4 Automatic Safety Controls

Even if the level instrumentation in the raffinate splitter column had operated properly, BP relied on the correct and timely action by operators and following procedures to prevent excessive column liquid levels. The tower was not equipped with automatic shutdowns or safety interlocks triggered by a high level, either of which could have provided additional protection against tower overfill.

While procedures are essential in any process safety program, they are regarded as the least reliable safeguard to prevent process incidents. The CCPS has ranked safeguards in order of reliability (Table 3).

Passive safeguards, such as reduced inventory of hazardous substances, cannot readily fail, but as in this case, are not always feasible. Procedural safeguards, such as operating procedures, because they rely on personnel consistently making correct and timely decisions while performing other duties and potentially while stressed or fatigued, are considered to be the least reliable.

Table 3. Safeguard reliability (CCPS, 1996b)

Reliability	Type	Examples
Most Reliable	Passive Safeguards	Reduced inventory of hazardous substances Use of chemistry with reduced toxicity
Less Reliable	Active Safeguards	Emergency shutdown systems Flare stacks
Least Reliable	Procedural Safeguards	Operating procedures

Failures with potentially severe consequences, such as overfilling a column in flammable service, may require multiple, redundant, active safeguards. Examples of active safeguards that could reduce the likelihood or consequences of column overfilling include, but are not limited to

- reducing and shutting off column feed on increasing high column level to prevent further material accumulation,
- shutting down the reboiler on high column level to prevent damage to trays or massive carryover of liquid from the column, or
- directing relief valve discharges to a high-capacity liquid knock-out system and flare stack.

In its report on the Milford Haven explosion, the U.K. Health and Safety Executive recommended an automatic safety device such as the shutdown of tower feed to prevent overfilling (HSE, 1997). The Instrument Society of America has suggested high level overrides on column feeds to reduce, and eventually halt, the flow of material into a column if the liquid level is high (Buckley et al., 1985). For columns where the consequences of overfilling could be severe, redundant instrumentation and a high reliability safety instrumented system (SIS) are recommended. Such systems, which operate independently of the normal operating controls, improve the reliability of safeguards and help reduce the likelihood of catastrophic failures such as the March 23, 2005, incident.

5.5 Pressure Relief and Disposal System Design

The investigation analyzed the design of the pressure relief system on the raffinate splitter tower and the disposal of the relief streams via the disposal collection header connected to the blowdown drum and stack. The analysis focused on the design basis of the relief and disposal system, calculations of relieving rates, and placement of equipment. The design basis was compared against the definition provided by the EPA in guidance materials for its Risk Management Program (40 CFR, Part 68):

> Design basis means documenting how the loads and sizes of the relief system, as well as inlet and outlet sizes were determined. This includes a description of overpressure scenarios considered, the scenario that creates the largest load to be relieved, the assumptions used and if the device meets a certain code…. (EPA, 2003).

The importance of properly documenting the design basis of relief systems is discussed in the third edition of *Lees' Loss Prevention in the Process Industries*:

> The core purpose of the relief system design basis documentation is two-fold: (1) to ensure that the entirety of the process unit is adequately protected against all credible sources of overpressure, and (2) to ensure that this design basis information is

> available to all interested parties throughout the operating life of the unit. These goals may be satisfied if the documentation captures the analysis process of the original designers of the unit's pressure relief system (Mannan, 2005).

The analysis must also address credible overpressure scenarios to ensure that the relief devices are equipped to safely dispose of the effluent while not compromising overpressure protection.

5.5.1 Safety and Engineering Standards

The Texas City refinery was owned and operated by Amoco Corporation prior to the merger with BP (Appendix D). Hence, the refinery and its equipment were designed and operated in accordance with Amoco and U.S. industry engineering codes and process safety standards. After the merger, former Amoco sites continued using the existing safety and engineering standards. Amoco and BP had developed a number of safety standards and engineering specifications that applied to safety relief valves, collection headers, and effluent systems; the most pertinent in use at Texas City were

- Process Safety Standard No. 6, "Flare, Blowdown, Pressure Relief, Vent and Drain Systems for Process Units," originally issued September 20, 1977 and updated in 1986, 1990, and 1994;
- Engineering Specification 49D-2, "ISBL Equipment Location and Spacing," October 21, 1992;
- A CV-PLT-DISP-E, "Civil Plant Disposal Systems Engineering Specification," October 1998; and
- "BP Chemicals Relief Systems Design Guide", Draft 1B, June 2001.

5.5.2 Pressure Relief System Design Basis

Texas City management did not identify all credible overpressure scenarios, fully document potential overpressure events, or calculate relief flow rates for all the potential overpressure scenarios on the raffinate splitter (Appendix R). Without this information, Texas City management could not ensure that the blowdown disposal system was safely designed. The lack of design basis documentation also points to a failure of PSM systems, such as process safety information and PHA requirements.

5.5.3 Blowdown System Design Basis

No evidence suggests that an analysis had been conducted to determine if the ISOM blowdown drum was safely designed. BP was unable to provide the CSB with any documents from the historical files concerning the original design basis of the blowdown drum and stack. No documents could be found indicating or showing that the blowdown drum could safely handle the effluent when the Heavy Ultraformate Fractionator (HUF) was installed in 1976, or after it was converted to a raffinate splitter in 1985 (Appendix E.1). While a contractor evaluated the other headers discharging into the blowdown drum when the ISOM unit was converted to a Penex reactor, the header from the raffinate splitter tower was not included in the evaluation. A BP engineer reviewed the results of the contractor's study in March 1994 and erroneously concluded that all the relief headers had been examined and were properly sized. His conclusion was then used as justification for closing an action item from the 1993 PHA to review the unit's relief valves to ensure that they were properly sized for current operation. And a 2003 process safety analysis action item for a review of the unit's relief valves was never completed; the target date was March 31, 2005, eight days after the explosion.

5.5.4 Process Safety Standard No. 6

The Texas City refinery did not follow the requirements of Amoco's Process Safety Standard (PSS) No. 6 (adopted by BP), which did not allow new atmospheric blowdown systems and required existing blowdown systems to be phased out. The policy required stacks to be converted to flare or closed system configurations "when the size of the existing facility is outgrown or when major modifications are made to the existing facility." The policy also did not allow quenched blowdown systems (such as the ISOM) to relieve to the atmosphere. Based on this policy, the following requirements or events should have triggered the replacement of the ISOM blowdown system:

- When the HUF fractionator was converted to a raffinate splitter tower in 1985, the existing quenched blowdown drum should have been converted.
- The replacement of the blowdown drum and stack in 1997 was a major modification to the ISOM unit.[123]
- A major modification also occurred in 2003 when the original design intent of the blowdown drum was significantly altered after the quench capabilities of the drum were impaired due to corrosion. The blowdown drum remained in disrepair until the time of the incident.

The purpose of PSS No. 6 was to ensure, "safe design of those systems in hydrocarbon processing units which are in place to control releases of hydrocarbons or potentially toxic materials to the environment. In general, release of these materials into closed systems is preferable. Containment, handling and proper disposal of such materials is critical to unit and personnel safety." The CSB concluded that PSS No. 6 required that the ISOM blowdown system should have been replaced for safety reasons.

5.5.5 Amoco Engineering Specification 49D-2

The blowdown drum and stack did not meet the Amoco engineering specification for spacing and location of refinery process unit equipment. Section 7.4 of this specification states that blowdown stacks be "located remote from other equipment, preferably OSBL (outside battery limits) and on the downwind side of the unit. The clear space between blowdown facilities and other equipment should be a minimum of 40 feet (12.2 m)." The blowdown drum and stack were located in the northwest corner of the ISOM

[123] BP managers stated in interviews after the incident that the 1997 project was a "replacement in kind" and did not trigger the conversion to a flare system. The policy did not contain an "in kind" exemption, nor did any historical record exist that showed that such an exemption was ever relied upon.

unit, inside the battery limits[124] (ISBL). The Amoco engineering specification states that major deviations from this guideline will need approval from the Refinery Process Safety Committee, but no evidence was found to indicate that the Texas City refinery ever sought approval to deviate from this standard. This standard should have been reviewed during PHA revalidations and facility siting studies; if it had, then the removal of the blowdown drum would have been evaluated.

5.5.6 Amoco Engineering Specification A CV-PLT-DISP-E

The blowdown drum and stack did not meet Amoco engineering specifications for plant disposal systems, which required that blowdown systems discharge to a vapor recovery system or a flare, rather than to the atmosphere. In 1998, Amoco Corporation Engineering Specification, A CV-PLT-DISP-E, “Civil Plant Disposal Systems Engineering Specification,” was issued. This specification defines “technical requirements for design of drain, vent, pump-out, blowdown, and sanitary sewer systems in plant processing facilities,” and defines a blowdown system as one that provides a means of safely and quickly removing process streams from a processing facility in an emergency. The general requirements of this standard state: “If deviation from this specification is necessary to conform to equipment design, unusual operating conditions, or existing facilities, approval to do so shall be obtained from Company,” yet the CSB found no evidence to indicate that the Texas City refinery ever sought approval to deviate. This specification states that whether hot hydrocarbons are released to a blowdown system and quenched, or cold hydrocarbons are drained into a blowdown drum, the drum will be vented to a flare or vapor recovery system, not directly to the atmosphere.

[124] The battery limit is an area in a refinery or chemical plant encompassing a process unit or battery of units with the unit(s)’s related utilities and services (Parker, 1994).

5.6 Previous Attempts to Remove Blowdown Drums

During the 15 years prior to the March 2005 incident, a number of proposals were made to remove blowdown stacks that vent directly to the atmosphere at the Texas City refinery, but none were implemented, primarily due to cost considerations.

5.6.1 1991 Flare/Blowdown Strategy

In mid-1991, in response to recent changes to the EPA Clean Air Act and various state requirements to disclose non-routine process vent sources, the Amoco Refining Planning Department (ARPD) proposed a strategy to eliminate blowdown stacks that vented to the atmosphere. In 1992, ARPD decided not to include separate funding for flare and blowdown work in the 10-year capital plan because neither federal nor state regulations were likely to require that relief valves be routed to closed systems in the foreseeable future. Instead, Amoco refineries were directed to identify and correct all deficiencies in equipment protection, including installation of common flare systems and projects, to correct Amoco PSS No. 6 deficiencies.

5.6.2 1992 OSHA Citation

In 1992, OSHA issued a serious citation to the Texas City refinery alleging that nine relief valves from vessels in the Ultraformer No. 3 (UU3) did not discharge to a safe place and exposed employees to flammable and toxic vapors. One feasible and acceptable method of abatement OSHA listed was to reconfigure blowdown to a closed system with a flare.[125] Amoco contested the OSHA citation.

[125] OSHA Citation No. 107617789, item 2, 3/30/1992.

In March 1994, OSHA and Amoco agreed to a settlement[126] regarding the 1992 citation. As part of that settlement, OSHA agreed to withdraw the citation, and Amoco stipulated that the conditions described in the violation had been analyzed in accordance with API Recommended Practice 521, “Guide for Pressure-Relieving and Depressuring Systems,” and that the hazardous conditions cited did not exist or had been corrected. The agreement also allowed OSHA or its consultants access to the workplace to review Amoco’s analysis of the conditions to verify compliance; however, OSHA did not conduct a follow-up inspection.

5.6.3 1993 Amoco Regulatory Cluster Project

The 1993 Amoco Regulatory Cluster Project was initiated to resolve compliance issues with all liquid waste regulations by installing state-of-the-art, double-lined, 100 percent segregated sewer systems at each process unit. All blowdown stacks would be eliminated and replaced with flares and knockout drums for maintenance and all liquid waste. High-risk areas would also have double-contained sumps installed to catch drips and drain rain water. However, due to project costs of $400 million, Amoco decided not to fund the project.

5.6.4 2002 NDU Flare line

During project development for the construction of the NDU and its flare system in early 2002, the contracted engineers sizing the flare line asked if the line should be sized to accommodate process streams from the ISOM unit as well. They noted that if the ISOM used the same flare line as the NDU, it would save about 1,000 feet (305 m) of pipe. If not, the proposed line size to the NDU flare could be reduced, saving $150,000. Due to uncertain future regulatory requirements and financial pressures, the

[126] Occupational Safety and Health Review Commission (OSHRC) Docket No. 92-1394, 92-1395.

refinery manager stated that only the original project as approved was to proceed and to "bank the savings in 99.999 percent of the cases."[127] Consequently, the ISOM unit tie-in was not made.

5.6.5 2002 Clean Streams Project

As a result of compliance issues with the EPA's environmental regulations, including the "National Emissions Standard for Hazardous Air Pollutants" (NESHAP) standard[128] for benzene waste and volatile organic compounds (VOC),[129] the Texas City refinery health, safety, and environment (HSE) department initiated a capital project, called "Clean Streams," in summer 2002. The project was assigned to a BP process engineering group with support from outside engineering firms, and involved either removing all liquid streams routed to blowdown stacks or installing emission controls. The short-term goals centered on identifying and measuring non-relief valve streams going to blowdown drums and identifying solutions to eliminate the sources discharging to blowdown drums. Long-term goals included eliminating blowdown stacks and initiating projects to install closed systems or flares for relief valve disposal. A presentation to the EPA in November 2002 included a slide on the Clean Streams project indicating that BP intended to remove all streams, other than relief valves from blowdown systems, to achieve rapid compliance with benzene waste issues.

As the ISOM unit was going to be shut down for a turnaround in early 2003, it was one of the first refinery units evaluated for benzene elimination. One option considered by the Clean Streams project team was to reconfigure the blowdown drum as a flare knockout drum and route its discharge to a flare to reduce benzene emissions. However, because the relief valve and header study was not up-to-date, this option was not selected. The ISOM unit relief valve and header study should have been completed before the first unit PHA was completed in 1993 (see Section 5.5.3). The Clean Streams project team discovered

[127] Email "Re: Line size for NDU flare," *from Refinery Operations Manager*, January 9, 2002.

[128] 40 CFR 61.340.

[129] 40 CFR 63.640.

in September 2002 that no study existed for the ISOM unit, and that budget cuts had delayed completion of the planned ISOM unit relief valve and header study for at least a year until the end of 2004.

Instead, the team decided to divert benzene-containing streams to segregated wet/dry closed systems with relief valves still venting to the blowdown drum. This took advantage of an exemption in the environmental regulations for emergency releases. Tie-ins for the wet/dry closed systems were done during the 2003 turnaround so these systems could be installed later.

As the Clean Streams project costs rose from $6 to $89 million, its proposed scope was discussed and redefined by BP managers, project engineers, and environmental personnel during an April 2003 "Setting Business Priority" workshop. After the meeting, the project scope changed from converting blowdown drums to emergency use to only attaining compliance with the refinery's two mega-gram-per-year limit for benzene waste. Consequently, the wet/dry system project in the ISOM unit was deemed unnecessary to meet the limit, the project was cancelled, and the wet/dry system was never installed.

The primary driver for the Clean Streams project evolved over time to focus on achieving compliance with EPA benzene waste regulations as soon as practical; safety and engineering specifications were not considered or addressed. Due to scheduling pressures from the upcoming turnarounds, the Cleans Streams project did not follow safeguards that were part of BP's Capital Value Process (CVP), including consideration of safety and engineering policies, such as those discussed in sections 5.5.4 through 5.5.6.

5.7 API 521 Guidelines

At the time of the March 23, 2005, incident, the American Petroleum Institute (API) Recommended Practice No. 521, "Guide for Pressure-Relieving and Depressuring Systems," (1997) was the generally accepted industry standard for pressure relieving and disposal systems. As Amoco asserted to OSHA in the 1994 citation settlement agreement, Amoco used an earlier addition of this guideline to evaluate its blowdown drums. The CSB also evaluated this guideline to determine its effectiveness in addressing hazards posed by blowdown drums with integral stacks open to the atmosphere.

The API 521 guidelines are divided in four main sections: causes of overpressure, determination of individual relieving rates, selection of disposal systems, and disposal systems. Gaps and ambiguities were noted in the guidelines and are discussed below.

5.7.1 Tower overfilling scenario

Although the API guidance covers 16 potential causes of overpressure, it does not address the potential overpressure hazard of vessel liquid overfill, or the hazard of a large liquid release to a disposal drum that vents directly to the atmosphere.

5.7.2 Selection of disposal systems

In “Selection of a Disposal System,” Section 4 of the guideline, there is no reference to the type of disposal system operating in the ISOM unit at BP Texas City; namely, multiple relief valves venting to a disposal collection header discharging to a blowdown drum fitted with an atmospheric vent stack. In section 4.6, “Disposal of Liquids and Condensable Vapors,” the short subsection 4.6.1.3 states that relief valves that discharge hot hydrocarbon liquids or vapors may be piped to a header that terminates in a quench drum. Subsection 4.6.1.3.1 indicates that a type of quench drum may be connected to a vent stack or flare. The ISOM blowdown drum had water sprays for quenching, but they were inoperable. Quench fluid is designed to be sprayed on hot vapors and will not prevent the release of volatile hydrocarbon liquids to the atmosphere if overfilled. This two-paragraph subsection does not discuss the sizing of the drum for liquid or vapor release scenarios, nor does it advise on the safe siting of the vent stack.

5.7.3 Sizing the knockout drum

Section 5.4.2.1, "Sizing a Knockout Drum," of the guideline, asserts that sizing is "generally a "trial-and-error process." A liquid overfill scenario is not considered. In fact, the guidance states:

> However, it would usually not be necessary to consider the following volumes relative to vapor disengaging in the following situation: that in which the knockout drum is used to contain large liquid dumps from pressure relief valves from other sources where there is no significant flashing, and the liquid can be removed promptly.

The BP incident involved liquid overfill, not liquid/vapor disengagement. Even then, the guidance says that sizing the drum for large liquid dumps does not have to be considered if the liquid can be removed "promptly." The guidance does not define "promptly" or how to size a drum when the liquid cannot be removed "promptly."

5.7.4 Inherently safer approaches

The API 521 discussion of designing or selecting disposal systems does not address the concept that a flare system is an inherently safer design than an atmospheric vent stack because it safely combusts flammable hydrocarbons before they are vented to atmosphere, where they could become a serious fire or explosion hazard.

A flare system with a knockout drum is both a destruct and containment system. A properly sized knockout drum would contain a credible "worst case" scenario release. Containment is one of the main lines of defense against releases of hazardous materials (Kletz, 1998). The flare burner is a destruct system, which is an inherently safer option compared to dispersing flammables to the atmosphere from the blowdown drum vent stack.

API 521, Section 5.4.4, “Vent Stacks,” discusses stack sizing and minimum velocity directed at vents directly off pressure relief valves. There is no discussion of backpressure effects on relief valves and the potential impacts on stack discharge velocity from having varying numbers of relief valves discharge to a header system connected to an atmospheric vent stack. In the ISOM unit, 58 emergency relief valves vented into disposal collection headers that discharged into the blowdown drum, many of which might operate simultaneously. The section does discuss the issue of possible liquid accumulation from vapor condensation, but not from a large liquid release. One alternative mentioned to avoid liquid accumulation is the installation of “a small disengaging drum” at the base of the vent stack, but the need for a blowdown or quench drum to be sized for a potential large liquid release is not discussed. Little guidance is given for safely siting vent stacks in the process plant. In fact, the section on design details states that vent stacks are frequently located in a process area that contains equipment connected to the stack, and suggests that the stack can often be more economically supported from a fractionating tower, chimney, etc. This suggestion ignores the safety implications of a potential large liquid or low discharge velocity vapor release in the middle of a process unit.

5.8 Conclusion

Based on the analysis of the relief system, the blowdown drum was undersized and the emergency relief system design did not address the potential of a large liquid release in the event the raffinate splitter tower overfilled. After the March 23, 2005, incident, BP evaluated the 22 blowdown systems at its five U.S. refineries and found that 17 handled flammables. BP has publicly pledged to eliminate all atmospheric blowdown systems in flammable service at all five of its U.S. refineries.

In light of the ambiguities and gaps discovered in reviewing API 521, CSB issued a recommendation to API on October 31, 2005, (Appendix C) to revise its recommended practice. OSHA’s PSM standard[130]

[130] 29 CFR 1910.119(d)(3)(i)(D), “Process Safety Management of Highly Hazardous Chemicals.”

requires that relief system designs comply with "recognized and generally accepted good engineering practices." Published PSM compliance guidelines call for inspections to ensure that "destruct systems, such as flares, are in place and operating" and that "pressure relief valves and rupture discs are properly designed and discharge to a safe area" (CPL 2-2.45A, 1994). Therefore, the CSB recommended that OSHA implement a special emphasis program for oil refineries to focus on blowdown drums that discharge directly to the atmosphere and their design (Appendix C).

6.0 TRAILERS

6.1 Placement of Temporary Structures

BP's placement of occupied trailers close to the ISOM unit was a key factor leading to the fatalities from this disaster. All 15 who died during the March 23, 2005, incident were in or around trailers. The trailers were sited in this area primarily for convenience: the unoccupied area between the ISOM and NDU units was selected because it was across the road from the Ultracracker, (ULC) and would be a convenient staging area for the contractors in their turnaround work (Figure 15). The CCPS noted that this practice is an increasing trend:

> Temporary, nonpermanent structures may be used at processing facilities. The most common are mobile office trailers used during construction or periodic major unit overhaul or turnaround. A common practice is that these temporary offices are located near processing areas for convenience and are not removed on completion of the job; thus, they transition from temporary to semi-permanent (CCPS, 2003).

6.2 History of Trailers in the Area

BP had been using trailers as temporary office spaces for several years at the Texas City refinery. A survey by the Texas City Facilities and Services department showed that in 2004, 122 trailers were in the refinery with an estimated occupancy of 800. These trailers were generally used to house employees and contract workers during turnaround periods. BP policy allowed trailers to be sited near process units based on the results of a screening process, which included a building analysis.

The area between the NDU and the ISOM had been viewed as an appropriate location to site trailers to be used during turnarounds for years largely for reasons of convenience. In fact, support utilities had been installed in that area in 2002 specifically for use by trailers in the turnarounds when the NDU was constructed and never removed. In summer 2003, a series of emails circulated in the BP Oils Turnaround Network[131] questioned whether changes were needed in turnaround trailer siting practices, or whether explosion-proof turnaround trailers should be used, in light of the findings of recently completed Major Accident Risk (MAR) studies[132] showing that turnaround trailers could be subject to potential explosion overpressures in certain areas of refineries. Although the BP Texas City refinery also identified this turnaround trailer siting concern as an issue, no evidence was found to indicate that this issue was resolved prior to the March 23, 2005, explosion.

6.2.1 2005 Turnaround

While planning for the 2005 ULC unit turnaround, in September 2004 BP sited a double-wide trailer between the NDU and ISOM to house employees for the Motorization Project. Nine others were located in the same area to support the ULC turnaround, but a MOC was not conducted for any of them despite being required by BP policy (Figure 15). (Appendix F provides further information on the location, construction, and use of all the trailers sited in this area.)

6.3 BP Texas City Facility Siting Practices

The policies, procedures, and practices being used at the Texas City refinery for facility siting were examined to determine why the trailers were placed so close to hazardous process areas. As most refinery units handle large quantities of flammable liquids, they are subject to the requirements of the OSHA PSM standard (Section 11.1). The PSM standard requires that facility siting be addressed as one element of a PHA using an appropriate methodology [29 CFR 1910.119(e)(2) and (3)(v)]. In its compliance directive

[131] This peer network, which included representatives from all BP refineries, met periodically and exchanged emails to discuss best practices for improving turnarounds.

[132] These voluntary studies conducted by BP assessed societal risk by determining the risk of multiple facilities (over three) from all potential scenarios at a particular site. The MAR study, conducted in March/April 2003 at the Texas City site, identified the top 80 risks, but none included the ISOM unit or blowdown drums.

[CPL 02-02-045], OSHA interpreted facility siting to mean “the location of various components within the establishment” in relation to PSM-covered process(es).

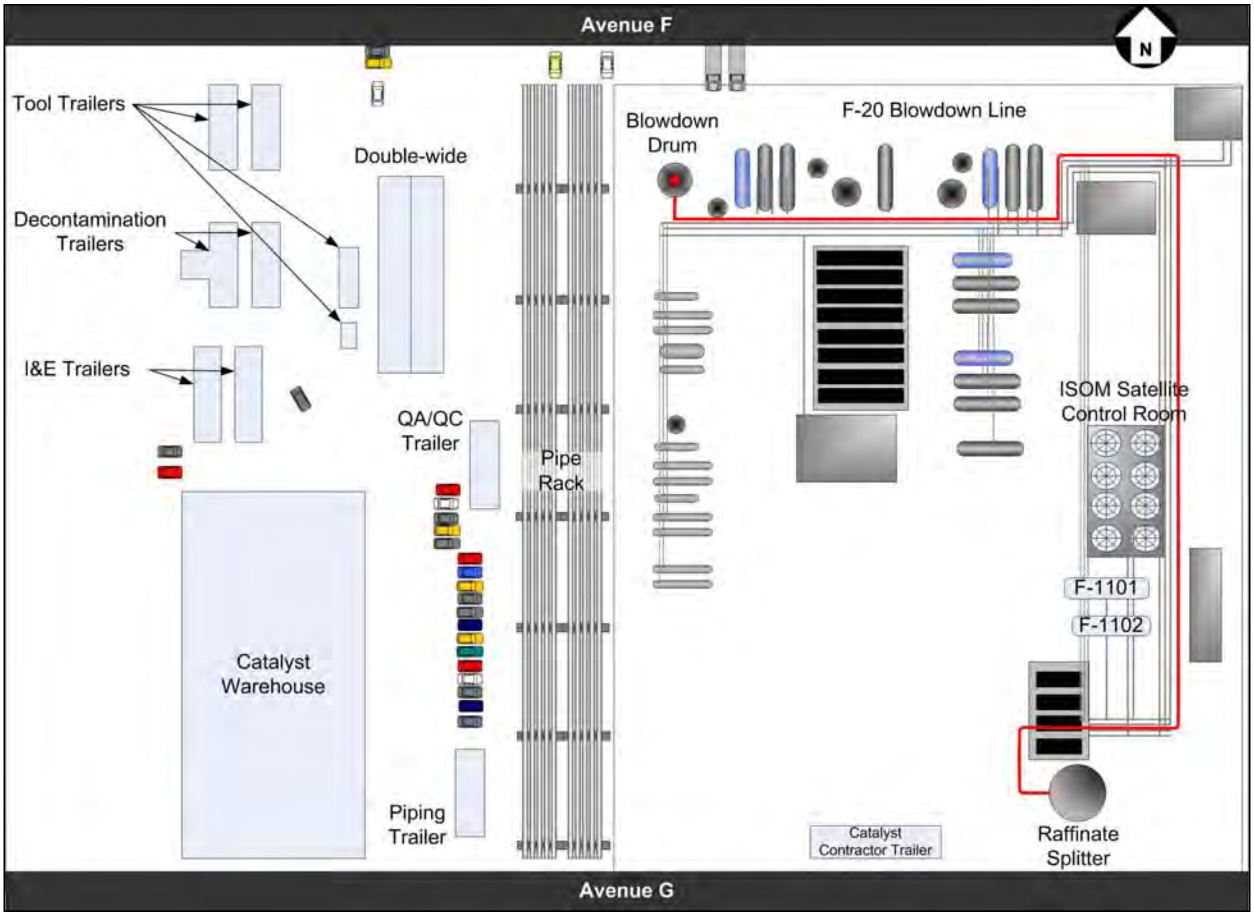

Figure 15. Trailer area and adjacent ISOM unit

6.3.1 Amoco *Facility Siting Screening Workbook*

Because the Texas City refinery was owned and operated by Amoco Corporation at the time the initial refinery-wide siting analysis was conducted in 1995, the refinery used the Amoco Petroleum Products Sector (PPS) Refining *Facility Siting Screening Workbook* as its methodology to analyze siting (Amoco, 1995). After the BP-Amoco merger in 1999, the Texas City refinery continued to use the Amoco workbook, even though BP Oil had been using a different risk-benefit approach in its refineries since the mid-1990s (Fryman, 1996). In fact, the facility siting analysis was revalidated in 2002 using the Amoco workbook, even though the BP Group had adopted and published a new group risk criteria (Mogford 2005, pg. 98). The workbook generally follows API 752 (1995), but contains some differences (Appendix F.1.1) that made it less protective (see additional discussion in Section 6.4 and Figure 16). The workbook sets forth a methodology for assessing risks involved in locating buildings with respect to process. Although the limitations of this workbook (e.g.. potential for trailer damage from a vapor cloud explosion and annualized occupancy of highly populated, short-duration turnaround trailers) were pointed out in a September 2004 email forwarded from the Whiting refinery to the Texas City PSM manager, these limitations were dismissed because the MOC PHA checklist for temporary trailer siting called for a distance of 350 feet (107 m) from the process, and at that distance the risk of a fatality was extremely low. However, the 350-foot (107 m) distance trigged a need for an analysis, but did not prevent a trailer from being placed closer than 350 feet (107 m).

6.3.2 MOC Procedures for Facility Siting

To address potential safety and health hazards of buildings introduced into the refinery between the refinery-wide siting studies, such as temporary mobile office trailers used in unit turnarounds, the refinery also required all newly sited structures to be evaluated under its MOC procedure, which also required that a PHA be conducted. As the trailers involved in the 2005 explosion near the ISOM blowdown drum and stack were placed there after the 2002 facility-wide siting study was completed and the next revalidation was not scheduled until 2007, facility siting for trailers sited during the 2005 turnaround were addressed using the refinery's MOC procedure.

6.3.3 What If/Checklist Methodology

The refinery used a What If/Checklist methodology for PHAs involving trailer siting. After a "What If" hazard analysis, a trailer siting checklist needed to be completed. The checklist was the first step in the screening process to determine if the building could be screened out based solely on its distance from the process unit. One checklist question asked if the trailer was to be located within 350 feet (107 m) of a process unit. If the answer to this question was "Yes," then further screening was required, which involved analyzing the building siting using the Amoco workbook.

6.3.4 MOC Implementation Problems with Trailer Siting

On September 27, 2004, BP Texas City staff completed a MOC form, which indicated that a double-wide mobile office trailer would be temporarily sited in the open area between the ISOM and NDU units for use by the Motorization Project during the upcoming ULC turnaround; the intention was to remove it when the project was completed at the end of April 2005. The MOC team conducting the PHA for this trailer did a "What If" analysis, using questions brainstormed by the MOC team, and then completed the checklist. As the trailer was closer than 350 feet (107 m) from both the ISOM and NDU units, they correctly answered the question on the checklist and were directed to perform a building siting analysis. However, none of MOC team members had been trained to use the Amoco workbook and thus did not understand how to do the building siting analysis. In lieu of an analysis that would have considered siting hazards, the MOC team attached a drawing showing the proposed interior configuration of the trailer and measured its location from the catalyst warehouse.

In January and February 2005, nine other trailers were sited between the ISOM and NDU without conducting a MOC. For siting purposes, the siting workbook specifically instructs users to consider clusters of buildings, such as turnaround trailers, as one building, which the team did not do. By conducting only one MOC, the occupancy load of the other trailers was never considered to increase risk.

In addition, the MOC procedures clearly state that the proposed change – in this case the siting of the first trailer – cannot be initiated until all action items identified in the PHA have been resolved. Although two action items were still pending from the MOC at the time of the March 2005 explosion, this trailer had been occupied by contractor personnel since November 2004, and the ISOM unit superintendent had never approved the MOC. After the March 2005 incident, BP determined that a majority of the mobile office trailers were sited without applying the MOC process and thus no PHAs or siting assessments were completed.

6.4 API 752 Guidelines

One industry standard used by the chemical, petrochemical, and hydrocarbon processing industries to evaluate facility siting in a PHA is API 752, “Management of Hazards Associated with Locations of Process Plant Buildings.” Because this guideline was also the basis for the BP Texas City facility siting studies, the CSB evaluated this guideline, which uses a three-stage analysis process to identify hazards and manage risks to building occupants from explosion hazards. Buildings screened out during one of the stages require no further evaluation. The guideline also allows companies to develop specific criteria pertaining to occupancy levels, evaluation-case events, consequence modeling/analysis programs, and risk acceptance criteria (Section 2.4.1, API 1995). Consequently, the values chosen by each company for these criteria will affect how buildings are screened.

API 752 does not address whether the convenience of placing of temporary mobile structures, like trailers, close to process units handling high hazardous chemicals outweighs the risk to occupants. Nor does it establish a minimum safe distance among various types of buildings and hazardous process units. The guidelines note that occupancy is normally based on an annual average and recommends that weekly occupancy rates vary from 200 to 400 person hours each week (the difference between five and 10 full-time employees being exposed to risk). Additionally, peak occupancy varies from five to 40 personnel. Yet by allowing this amount of latitude, companies applying API 752 using a high-occupancy criterion could place employees at significant risk and still fall within the allowances of the guidelines. Also, using an annual average as a basis for occupancy is inappropriate for trailers that will be occupied only several months during a unit turnaround.

The data API uses to assess vulnerability of building occupants during building collapse is based mostly on earthquake, bomb, and windstorm damage to buildings. However, as vapor cloud explosions tend to generate lower overpressures with long durations (and thus relatively high impulses) (Gugan 1979), the mechanism by which vapor cloud explosions induce building collapse does not necessarily match the data being used in API 752 to assess vulnerability. The CSB found that this data is heavily weighted on the response of conventional buildings, not trailers, which are not typically constructed to the same standards. Thus, when the correlations of vulnerability to overpressure from the March 23, 2005, explosion (Figure 16) are compared against the API and BP criteria (Section 6.3.1), they were both found to be less protective in that both under-predict vulnerability for a given overpressure. Also, the data used by both API and BP to estimate vulnerability[133] does not include serious injuries to trailer occupants as a result of flying projectiles, which are typically combinations of shattered window glass and failed building components, heat, fire, jet flames, or toxic hazards.

In light of these findings and because API 752 is commonly used as a basis for facility siting, the CSB made an urgent recommendation to API regarding trailer siting and recommended either revising API 752 or issuing a new standard to address the issues (Appendix C).

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[133] The Amoco workbook data used by BP Texas City was based primarily on fatalities, while the API data was based on fatalities and life-threatening injuries. However, OSHA standards are based on Section 5 of the Occupational Safety and Health Act of 1970, which requires employers to prevent death as well as serious physical harm (such as broken bones and severe lacerations).

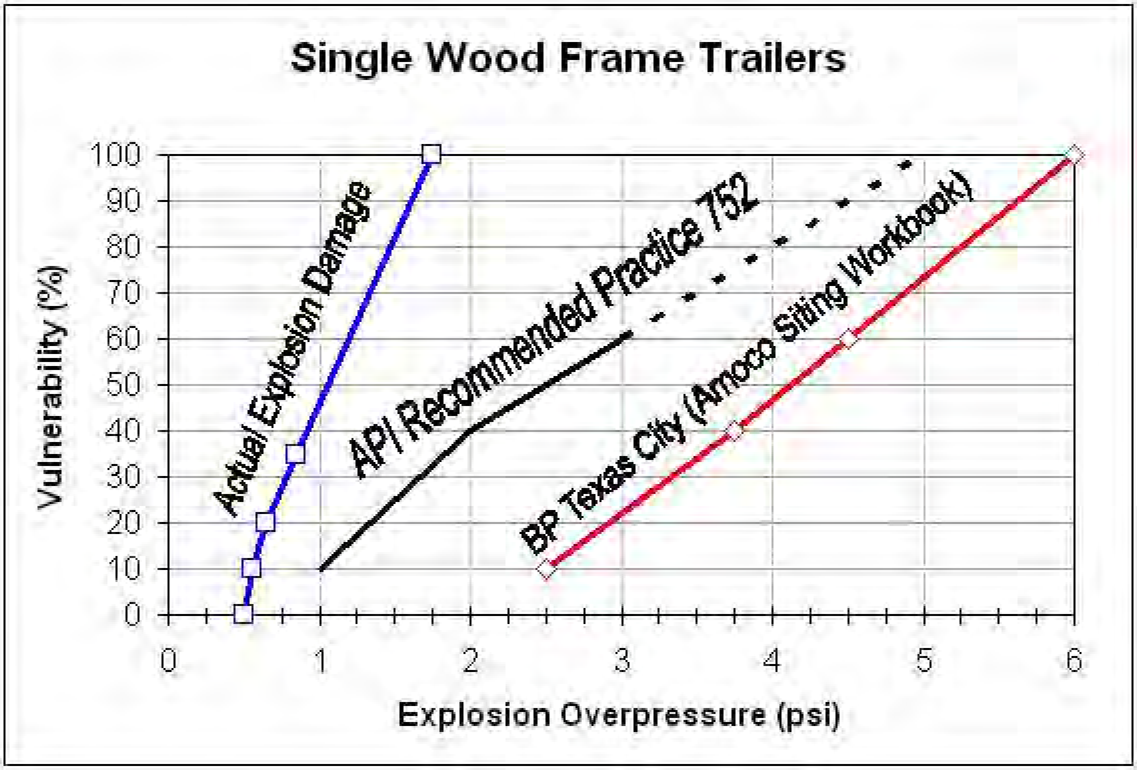

Figure 16. Comparison of explosion damage based on API and BP Texas City criteria

6.5 BP Actions After the Explosion

In its internal investigation of the March 23, 2005 explosion, BP adopted new policies for trailer siting at its facilities. Appendix 37 in the "Fatal Accident Investigation Report" (Mogford, 2005) outlines the specifics of BP's new siting policy; trailer siting is now based on exclusion zones for areas where explosions are possible, and all occupied trailers should be located outside of vulnerable areas even if this means a location outside the refinery. A large number of Texas City personnel were relocated to a permanent building away from the refinery after the incident.

7.0 MECHANICAL INTEGRITY

The goal of a mechanical integrity program is to ensure that all refinery instrumentation, equipment, and systems function as intended to prevent the release of dangerous materials and ensure equipment reliability. An effective mechanical integrity program incorporates planned inspections, tests, and preventive and predictive maintenance, as opposed to breakdown maintenance (fix it when it breaks). This section examines the aspects of mechanical integrity causally related to the incident.

7.1 Instrumentation Failures

The instruments associated with the raffinate splitter tower and the blowdown drum were causal factors in the BP Texas City incident. BP instrument technicians described the unit instrumentation as being run-down and in disrepair.

Table 4 summarizes those ISOM instruments whose failure contributed to the BP Texas City incident. The table includes instrument descriptions and functions, as well as the instruments' modes, causes and effects of failure. Details of post-incident instrument testing, inspection, and failure analysis are found in Appendix S.

Table 4. Instrumentation that failed to operate properly on March 23, 2005

Tag No.	Instrument	Function	Failure Mode	Likely Failure Cause	Effect
LT-5100	Raffinate Splitter Level Transmitter	Transmits a signal to the control system to indicate the level in the tower.	Incorrect reading prior to the incident	Instrument not calibrated for actual specific gravity of the ISOM process fluid, at operating temperatures.	Transmitter falsely showed the level in the tower bottoms below 100 percent and falling, when in fact the tower was overfilling.
LSH-5102	Raffinate Splitter Redundant (Hard-wired) High Level Alarm	Alarms when the level in the tower exceeds a maximum set value.	Failed to signal when the tower bottom level reached the assigned set-point.	Worn, misaligned components bound the mechanism.	Operators received no independent warning that the maximum bottom level had been exceeded.
LG-1002 A/B	Raffinate Splitter Sight Glass	Visually indicates tower level (level indication split across two sight glasses).	Sight glasses were dirty on the inside; tower level could not be visually determined.	Sight glass not cleaned.	Level transmitter calibration could not be effectively performed without sight glass verification. Operators had no backup to determine tower level.
LSH-5020	ISOM Blowdown Drum High Level Alarm	Alarms when the level in the blowdown drum exceeds a set value. This was the only high level alarm for the blowdown drum.	Failed to signal when the tower bottom level reached the assigned set-point.	Damaged level displacer ("float")	No warning that the blowdown drum level was above maximum.[134]
PCV-5002	3-lb Pressure Vent Valve for the Raffinate Splitter Reflux Drum	Available for operators to manually vent gases from the splitter overhead system.	Valve failed to open during startup testing.	Possible actuator stem binding, or intermittent pneumatic failure.	Unit was started up with a known malfunction of this pressure control valve.[135]

[134] Although this alarm failure did not contribute to the release, the CSB believes that if the alarm had functioned properly, the operators may have been alerted to the rising level in the drum and able to sound the emergency alarm, which may have led some personnel in the area to evacuate, reducing the consequences of the blast.

[135] The failure of PCV-5002 did not directly contribute to the raffinate splitter overfilling; however, startup of the unit should not have been allowed with this valve known to be malfunctioning, according to BP's own procedures.

7.2 Mechanical Integrity Management System Deficiencies

Mechanical integrity is one of 12 functional elements of OSHA's PSM rule [29 CFR 1910.119 (j)], which requires employers to establish written procedures to maintain the mechanical integrity of process equipment through

- testing and inspection,
- maintenance procedures and training,
- equipment design and selection,
- quality assurance of purchased equipment and spare parts, and
- equipment deficiency correction.

The goal of mechanical integrity is to ensure that process equipment (including instrumentation) functions as intended. Mechanical integrity programs are intended to be proactive, as opposed to relying on "breakdown" maintenance (CCPS, 2006). An effective mechanical integrity program also requires that other elements of the PSM program function well. For instance, if instruments are identified in a PHA as safeguards to prevent a catastrophic incident, the PHA program should include action items to ensure that those instruments are labeled as critical, and that they are appropriately tested and maintained at prescribed intervals.

The BP Texas City mechanical integrity program did not ensure that deficiencies, such as those found with the ISOM instruments and equipment, were identified and repaired prior to failure.

7.2.1 Process Safety Information

Accurate and current instrument data sheets and testing and calibration procedures are necessary for instrument technicians to ensure instrument reliability. The instrument data sheets for raffinate splitter tower level transmitter and a number of other ISOM instruments were not kept up-to-date or made available to maintenance personnel, likely resulting in miscalibration of the level transmitter. As a result, the transmitter provided false information to operators during the raffinate tower startup. The plant work order system also did not supply necessary calibration information or instrument testing procedures.

7.2.2 Maintenance Procedures and Training

The instrument technicians stated that no written procedures for testing and maintaining the instruments in the ISOM unit existed. Although BP had brief descriptions for testing a few instruments in the ISOM unit, it had no specific instructions or other written procedures relating to calibration, inspection, testing, maintenance, or repair of the five instruments cited as causally related to the March 23, 2005, incident. For example, the instrument data sheet for blowdown high level alarm did not provide a test method to ensure proper operation of the alarm. Technicians often used a potentially damaging method of physically moving the float with a rod (called “rodding”) to test the alarm. This testing method obscured the displacer (float) defect, which likely prevented proper alarm operation during the incident.[136]

7.2.3 Process Hazard Analysis (PHA)

The original 1993 PHA for the ISOM unit identified the level instrumentation on the raffinate splitter as a safeguard against tower overfilling. However, the raffinate splitter instruments were not included on the list of critical instruments.

In addition, a safety review of the ISOM unit relief system and blowdown drum identified the raffinate splitter level transmitter and alarm as justifications for concluding that tower overfill was not a credible scenario. However, neither the PHA nor the relief system review resulted in the raffinate splitter level

[136] While the blowdown drum high level alarm (which was mislabeled in the critical alarm database as “Cooling Tower Sump Low Level”) had no listed testing procedure, other listed ISOM testing procedures for high level alarms called for instrument technicians to manually “rod float to activate,” which was the procedure typically used for the blowdown drum high level.

instruments being designated as "safety-critical." The result was a history of ineffective maintenance for the level instruments. Further, no work history was found for the tower level transmitter for the five years prior to the incident.

7.2.4 Deficiency Management: The SAP Maintenance Program

In October 2002, BP Texas City refinery implemented the SAP (Systems Applications and Products) proprietary computerized maintenance management software (CMMS) system. SAP enabled automatic generation and tracking of maintenance jobs and scheduled preventive maintenance.

While the SAP software program can provide high levels of maintenance management, the Texas City refinery had not implemented its advanced features. Specifically, the SAP system, as configured at the site, did not provide an effective feedback mechanism for maintenance technicians to report problems or the need for future repairs. SAP also was not configured to enable technicians to effectively report and track details on repairs performed, future work required, or observations of equipment conditions. SAP did not include trending reports that would alert maintenance planners to troublesome instruments or equipment that required frequent repair, such as the high level alarms on the raffinate splitter and blowdown drum.

Finally, the Texas City SAP work order process did not include verification that work had been completed. According to interviews, BP maintenance personnel were authorized to close a job order even if the work had not been completed.

7.3 Summary

Several instruments in the ISOM raffinate splitter section failed, likely due to inadequate maintenance and testing, contributing to the incident. The mechanical integrity program did not incorporate the necessary training, tools, and oversight. The equipment data sheets were not kept up-to-date so that incorrect data, such as a wrong specific gravity value for the process hydrocarbons, resulted in miscalibration of critical instruments. Instruments with a history of problems, such as the tower high level alarm, were not tracked to ensure proper corrective action and avoid breakdown maintenance. Site practices did not ensure that instruments were tested and/or repaired before unit startup. Appropriate methods and procedures were not used for testing instrument functionality as with the blowdown drum high level alarm.

Mechanical integrity deficiencies resulted in the raffinate splitter tower being started up without a properly calibrated tower level transmitter, functioning tower high level alarm, level sight glass, manual vent valve, and high level alarm on the blowdown drum.

8.0 OTHER SAFETY SYSTEM PROBLEMS

8.1 Process Hazard Analysis (PHA)

PHAs in the ISOM unit were poor, particularly pertaining to the risks of fire and explosion. The initial unit PHA on the ISOM unit was completed in 1993, and revalidated in 1998 and 2003. The methodology used for all three PHAs was the hazard and operability study, or HAZOP.[137] The following illustrates the poor identification and evaluation of process safety risk:

- Consequences of high level and pressure in the raffinate splitter tower and high level in the blowdown drum and stack were not adequately identified. Overfilling the tower resulting in over-pressurization of the safety relief valves and liquid overflow to the blowdown drum and stack was not identified.
- High heat-up rates or blocked outlets were not identified as potential causes of high pressure.
- The sizing of the blowdown drum for containment of a potential liquid release from the ISOM was not evaluated. The safeguards listed for the blowdown drum and stack to protect against the hazard of overflow, such as the steam-driven pump-out pump and high level alarm, were insufficient to protect against the hazards. No recommendations were made by the PHA team to provide additional safeguards.

[137] A systematic method conducted by an interdisciplinary team in which process hazards and potential operating problems are identified using a series of guide words to investigate process deviations. If the causes and consequences of the deviations are significant and the existing safeguards are determined by the team to be inadequate, then a follow-up action is recommended.

- Previous incidents with catastrophic potential were not addressed. The 1998 HAZOP revalidation did not address the two documented incidents involving the blowdown drum that occurred in February 1994, nor was the January 16, 1999, incident addressed in the 2003 HAZOP revalidation (see Section 5.1).

8.2 Management of Change (MOC)

Changes made to processes, equipment, procedures, buildings, and personnel at the refinery were not systematically reviewed to ensure that an adequate margin of safety was maintained.

The refinery required that a MOC be initiated for any change that involved process chemicals, process/equipment technology, equipment piping, process control and instrumentation, operating procedures, safe operating limits, relief/safety systems, personnel/staffing/organization/outsourcing, and occupied buildings. The program revolved around the refinery Asset Superintendents, who were responsible for most aspects of the program. Support for the MOC program was provided by the refinery's PSM group, which managed the electronic MOC database, trained PHA leaders, and tracked resolution of MOC action items.

Every change that required a MOC also required a PHA so that the impact of the change on safety and health could be evaluated. Impacts of minor changes were typically assessed using the What If/Checklist methodology; for major changes, the HAZOP methodology was typically used. The MOC program intended that changes be authorized by the Asset Superintendent once the PHA was complete and all safety action items were addressed. However, this was not always done; for example, the siting of the double-wide trailer next to the ISOM unit was not authorized.

There were a number of misapplications of the refinery MOC policy for changes pertaining to the blowdown drum, the splitter tower, and occupied trailers (Appendix T).

Organizational changes that could adversely impact process safety, such as changes in the management structure, budget cuts, etc., generally were not evaluated. The American Chemical Council (ACC) recommends in its good practice guideline, “Managing Process Changes,” that organizational, personnel and policy changes be evaluated in MOC systems (CMA, 1993).

8.3 Auditing

8.3.1 Compliance Audits

A review of compliance audits at the Texas City refinery revealed that many of the process safety system deficiencies causal to the ISOM incident had been previously identified by BP auditors. The OSHA PSM standard, 29 CFR 1910.119(o)(1), requires compliance audits every three years to verify that procedures and practices developed under the standard are adequate and being followed. Noteworthy findings from the two previous PSM compliance audits are discussed below. A number of other audits were also conducted at the Texas City refinery to verify compliance with corporate and business unit policies and programs (see Section 9.4).

8.3.2 PSM Audits

Auditors with process safety experience from other BP facilities audited Texas City’s PSM program in 2001 and 2004, using an audit protocol developed by the BP Refining Group. These audits focused primarily on management systems, not verification of actual practices in the refinery. Although all PSM elements were evaluated during these audits, due to the time limitations of the audits (one week) and the sampling methods used, all PSM elements were not evaluated in every process unit at the refinery. The results of the PSM audit were given to the refinery business unit leader, process safety committee, PSM and health, safety, security, and environment (HSSE) departments, which were then responsible for developing a corrective action plan to address the audit’s findings.

8.3.3 2001 PSM Audit

The 2001 PSM audit addressed PHAs and incident investigations on the ISOM unit. Although no findings mentioned the ISOM unit specifically, the audit findings noted that 9 percent of PHA recommendations made since OSHA mandated PHAs remained open, and that some of these items dated back to the initial unit PHAs conducted in 1993. Also, 15 percent of these open items were found to be past their due dates. The audit also noted action items on incident investigations were not being closed out in a timely manner.

In other PSM areas, the audit team noted that a number of changes had occurred in operating units without initiating MOCs, and recommended refresher training on types of changes that needed to be managed under the MOC process. The audit team also discovered that a number of operating procedures were not current and did not accurately reflect practices on particular units. The team recommended a comprehensive audit of operating procedures at each unit.

8.3.4 2004 PSM Audit

The 2004 PSM audit for the ISOM unit addressed PHAs, operating procedures, contractors, PSSRs, mechanical integrity, safe work permits, and incident investigations. Again, no findings specifically mentioned the ISOM unit, but the audit noted that "engineering documentation, including governing scenarios and sizing calculations, does not exist for many relief valves. This issue has been identified for a considerable time at TCR [Texas City Refinery] (circa 10 yrs) and efforts have been underway for some time to rectify this situation but work has not been completed."[138]

The audit also found that the refinery PHA documentation lacked a detailed definition of safeguards, but noted that this would be addressed by applying layer of protection analysis (LOPA) for upcoming PHAs. However, the ISOM unit's last PHA revalidation was in 2003, and LOPA was not scheduled to be applied

[138] Executive Summary, "Process Safety Management Audit," BP South Houston, March 8-12, 2004.

until the unit's next PHA revalidation in 2008. The audit also noted that the refinery had no formal process for communicating lessons learned from incidents.

The audit team found a lack of specific training for newly assigned managers, superintendents, supervisors, and engineers, plus lack of a formal gun drill policy. They also found that process safety action item resolution was still a problem for the refinery (20 percent of open action items were overdue), and that changes were still being made before MOC sign-offs and action items had been resolved.

8.4 Controlling Vehicle Traffic and People During Startup

The likely ignition source for the vapor cloud was an idling vehicle parked close to the blowdown drum. Most of those injured or killed from the resulting explosion did not need to be in the area surrounding the ISOM during the hazardous period of unit startup. Policies applicable to control of vehicle traffic and non-essential personnel during abnormal conditions such as unit startup were examined as follows.

8.4.1 Traffic Safety Policy

The BP Texas City Traffic Safety Policy (TSP) outlines safety requirements for all vehicles operating inside the refinery. The TSP addresses basic vehicle operating rules and procedures, but does not mention

- plant or unit turnarounds,
- capital work projects, and
- traffic safety during abnormal conditions such as unit startup.

Interviews with employees revealed that special event coordinators wrote supplemental or modified traffic control plans for unit-specific turnarounds. Turnaround traffic control plans point out specific changes such as areas of the plant that are restricted to parking or traffic. The West Plant 2005 turnaround traffic control plan did not address vehicle access limitations during startup, shutdown, or other abnormal conditions.

The turnaround traffic control plan also did not address the use or parking of vehicles adjacent to the battery limits of process units. Drivers were not restricted from parking or leaving vehicles idling close to a process unit outer battery limit, where the vehicle engine could introduce a potential ignition source. However, the map (Appendix U) issued with the turnaround traffic control plan does indicate that no vehicles were to be parked along either side of Avenue F beside the NDU and ISOM units (the idling vehicle that was the likely ignition source, as well as a number of other vehicles, were in this area). Interviews with turnaround personnel indicated that this map was posted in turnaround trailers. Based on the number of contractor vehicles found parked along Avenue F after the incident, the prohibition against parking outlined on the map was not enforced.

8.4.2 Failure to Remove Non-Essential Personnel

As Section 3.5.2.1 discusses, the site had implemented a PSSR policy applicable to the ISOM startup that required sign-off that all non-essential personnel had been removed from the unit and neighboring units. Higher level management was required to sign off on the checklists, which included the requirement to remove non-essential personnel prior to the startup. None of the PSSR procedural steps were undertaken for the ISOM startup.

9.0 BP'S SAFETY CULTURE

The U.K. Health and Safety Executive describes safety culture as "the product of individual and group values, attitudes, competencies and patterns of behaviour that determine the commitment to, and the style and proficiency of, an organization's health and safety programs" (HSE, 2002). The CCPS cites a similar definition of process safety culture as the "combination of group values and behaviors that determines the manner in which process safety is managed" (CCPS, 2007, citing Jones, 2001). Well-known safety culture authors James Reason and Andrew Hopkins suggest that safety culture is defined by collective practices, arguing that this is a more useful definition because it suggests a practical way to create cultural change. More succinctly, safely culture can be defined as "the way we do things around here" (CCPS, 2007; Hopkins, 2005). An organization's safety culture can be influenced by management changes, historical events, and economic pressures. This section of the report analyzes BP's approach to safety, the mounting problems at Texas City, and the safety culture and organizational deficiencies that led to the catastrophic ISOM incident.

9.1 BP Texas City Explosion: An Organizational Accident

In the 30 years before the ISOM incident, the Texas City site suffered 23 fatalities. In 2004 alone three major incidents caused three fatalities. Many of the safety problems that led to the March 23, 2005, disaster were recurring problems that had been previously identified in audits and investigations. Shortly after the ISOM incident, two additional incidents occurred at the Texas City refinery in other process units due to mechanical integrity failures. And on July 21, 2006, the Texas City refinery had a fatality in an accident involving a motorized man-lift. This series of safety failures prompted the CSB to examine the safety culture of BP and its influence on the events that led to the ISOM incident.

Organizational accidents have been defined as low-frequency, high-consequence events with multiple causes that result from the actions of people at various levels in organizations with complex and often high-risk technologies (Reason, 1997). Safety culture authors have concluded that safety culture, risk awareness, and effective organizational safety practices found in high reliability organizations (HROs)[139] are closely related, in that "[a]ll refer to the aspects of organizational culture that are conducive to safety" (Hopkins, 2005). These authors indicate that safety management systems are necessary for prevention, but that much more is needed to prevent major accidents. Effective organizational practices, such as encouraging that incidents be reported and allocating adequate resources for safe operation, are required to make safety systems work successfully (Hopkins, 2005 citing Reason, 2000).

A CCPS publication explains that as the science of major accident investigation has matured, analysis has gone beyond technical and system deficiencies to include an examination of organizational culture (CCPS, 2005). One example is the U.S. government's investigation into the loss of the space shuttle Columbia, which analyzed the accident's organizational causes, including the impact of budget constraints and scheduling pressures (CAIB, 2003). While technical causes may vary significantly from one catastrophic accident to another, the organizational failures can be very similar; therefore, an organizational analysis provides the best opportunity to transfer lessons broadly (Hopkins, 2000).

The disaster at Texas City had organizational causes, which extended beyond the ISOM unit, embedded in the BP refinery's history and culture. BP Group executive management became aware of serious process safety problems at the Texas City refinery starting in 2002 and through 2004 when three major incidents occurred. BP Group and Texas City managers were working to make safety changes in the year

[139] HROs are described as organizations from higher risk sectors such as nuclear power plants, air traffic control, or nuclear aircraft carriers that have developed characteristics such as preoccupation with failure, reluctance to simplify, and mindfulness to operations, which enables them to more successfully manage unexpected events and suffer fewer incidents (Weick & Sutcliffe, 2001).

prior to the ISOM incident, but the focus was largely on personal rather than process safety.[140] As personal injury safety statistics improved, BP Group executives stated that they thought safety performance was headed in the right direction.

At the same time, process safety performance continued to deteriorate at Texas City. This decline, combined with a legacy of safety and maintenance budget cuts from prior years, led to major problems with mechanical integrity, training, and safety leadership.

9.2 Grangemouth Lessons—Focus on PSM

In 2000, three incidents at BP's Grangemouth refinery in Scotland included a large process unit fire and two serious upsets. The U.K. Health and Safety Executive investigated the causes of the incidents and released a major report in 2003 (HSE, 2003a). Three senior BP process safety engineers, including the BP Texas City PSM manager, published an article in 2004 summarizing the major lessons from the incidents (Broadribb et al., 2004), which were similar to those in the ISOM incident. The BP authors stated that one key lesson for industry was that preventing major incidents "requires a specific focus on process safety management over and above conventional safety management." They recommended that companies "develop key performance indicators (KPIs) for major hazards" to ensure that performance is monitored and to provide an early warning of process safety deficiencies, and concluded that "traditional indicators such as 'days away from work' do not provide a good indication of process safety performance."

[140] CCPS defines process safety as "a discipline that focuses on the prevention of fires, explosions and accidental chemical releases at chemical process facilities." Process safety management applies management principles and analytical tools to prevent major accidents rather than focusing on personal safety issues such as slips, trips and falls (CCPS, 1992a). Process safety expert Trevor Kletz notes that personal injury rates are "not a measure of process safety" (Kletz, 2003). The focus on personal safety statistics can lead companies to lose sight of deteriorating process safety performance (Hopkins, 2000).

BP also determined that "cost targets" played a role in the Grangemouth incident:

> There was too much focus on short term cost reduction reinforced by KPI's in performance contracts, and not enough focus on longer-term investment for the future. HSE (safety) was unofficially sacrificed to cost reductions, and cost pressures inhibited staff from asking the right questions; eventually staff stopped asking. Some regulatory inspections and industrial hygiene (IH) testing were not performed. The safety culture tolerated this state of affairs, and did not 'walk the talk' (Broadribb et al., 2004).

The U.K. Health and Safety Executive investigation similarly found that the overemphasis on short-term costs and production led to unsafe compromises with longer term issues like plant reliability.

The Health and Safety Executive also found that organizational factors played a role in the Grangemouth incidents. It reported that BP's decentralized management led to "strong differences in systems style and culture." This decentralized management approach impaired the development of "a strong, consistent overall strategy for major accident prevention," which was also a barrier to learning from previous incidents. The report also recommended in "wider messages for industry" that major accident risks be managed and monitored by directors of corporate boards.

BP Group did not systematically review its refinery operations and corporate governance worldwide to implement needed changes identified in the Health and Safety Executive report and in its own Task Force report, even though the Group Chief Executive told staff in October 2000 edition of BP's in-house magazine that BP would learn lessons from Grangemouth and other incidents.[141] The CSB found that a number of managers, including executive leadership, had little awareness or understanding of the lessons from Grangemouth. Moreover, BP Group leadership did not ensure that necessary changes were made to BP's approach to safety. They did not effectively address the need for greater focus on PSM, including

[141] Browne, J., 2000, "Browne, Take Action to put Safety First," *Horizon*, October 2000, p.39.

measuring PSM performance, nor did they resolve problems associated with BP's decentralized approach to safety.

The Baker Panel also noted "striking" similarities between the lessons of Grangemouth and the events of the Texas City explosion, most notably the lack of management leadership, accountability, and resources; poor understanding of and a lack of focus on process safety, coupled with inadequate performance measurement indicators; and untimely completion of corrective actions from audits, peer reviews, and past incident investigations. The Panel concluded that "in its response to Grangemouth, BP missed an opportunity to make and sustain company-wide changes that would have resulted in safer workplaces for its employees and contractors" (Baker et al., 2007).

9.3 BP's Approach to Safety—Lack of PSM Focus

9.3.1 Changes in the Safety Organization

Sweeping changes occurred in the HSE organization of the Texas City refinery after the 1999 BP and Amoco merger. Prior to the merger, Amoco managed safety under the direction of a senior vice president. Amoco had a large corporate HSE organization that included a process safety group that reported to a senior vice president managing the oil sector. The PSM group issued a number of comprehensive standards and guidelines, such as "Refining Implementation Guidelines for OSHA 1910.119 and EPA RMP."

In the wake of the merger, the Amoco centralized safety structure was dismantled. Many HSE functions were decentralized and responsibility for them delegated to the business segments. Amoco engineering specifications were no longer issued or updated, but former Amoco refineries continued to use these "heritage" specifications. Voluntary groups, such as the Process Safety Committees of Practice, replaced the formal corporate organization. Process safety functions were largely decentralized and split into different parts of the corporation. These changes to the safety organization resulted in cost savings, but led to a diminished process safety management function that no longer reported to senior refinery executive leadership. The Baker Panel concluded that BP's organizational framework produced "a number of weak process safety voices" that were unable to influence strategic decision making in BP's US refineries, including Texas City (Baker et al., 2007).

9.3.2 BP Group's HSE Management System

BP Group's "Getting Health, Safety, and the Environment Right" (GHSER) policy, established in 1997, was intended to provide a business-wide HSE management system. The BP document, "Getting HSE Right, A Guide for BP Managers," listed 91 mandatory HSE expectations to be implemented by BP Business Unit Leaders.[142] GHSER was BP's primary safety program and was monitored by BP Group. The implementation of GHSER was controlled by business units such as the Texas City refinery. Responsibility was placed on the Business Unit Leader to assure GHSER performance with the HSE expectations to the Group Chief Executive. (See Table 5 for brief descriptions of various upper management positions and Figure 17 for the line of accountability.)

Table 5. Upper management job position descriptions

Job Position/Group	Description
BP Group	Global business operations, including Refining and Marketing, headquartered in London
Group Executives	Corporate managers above the Business Unit Leaders
R&M	Refining and Marketing
BUL; Business Unit Leader	The top manager of a BP business unit
South Houston Site Director	The South Houston Site Director had full accountability for all refining and petrochemical products within the five business units of South Houston. He was responsible for the commercial performance of the Texas City refinery. The Site Director became the Texas City refining Business Unit Leader in spring 2004 when the South Houston site was dissolved.
Texas City Managers	Managers above the front line supervisor level

[142] A Business Unit Leader is the top manager of a business unit, which is a defined, free-standing commercial organization. In the BP system, business units receive centralized direction, but implementation is decentralized. In the BP organizational structure, a refinery such as Texas City is typically a separate business unit.

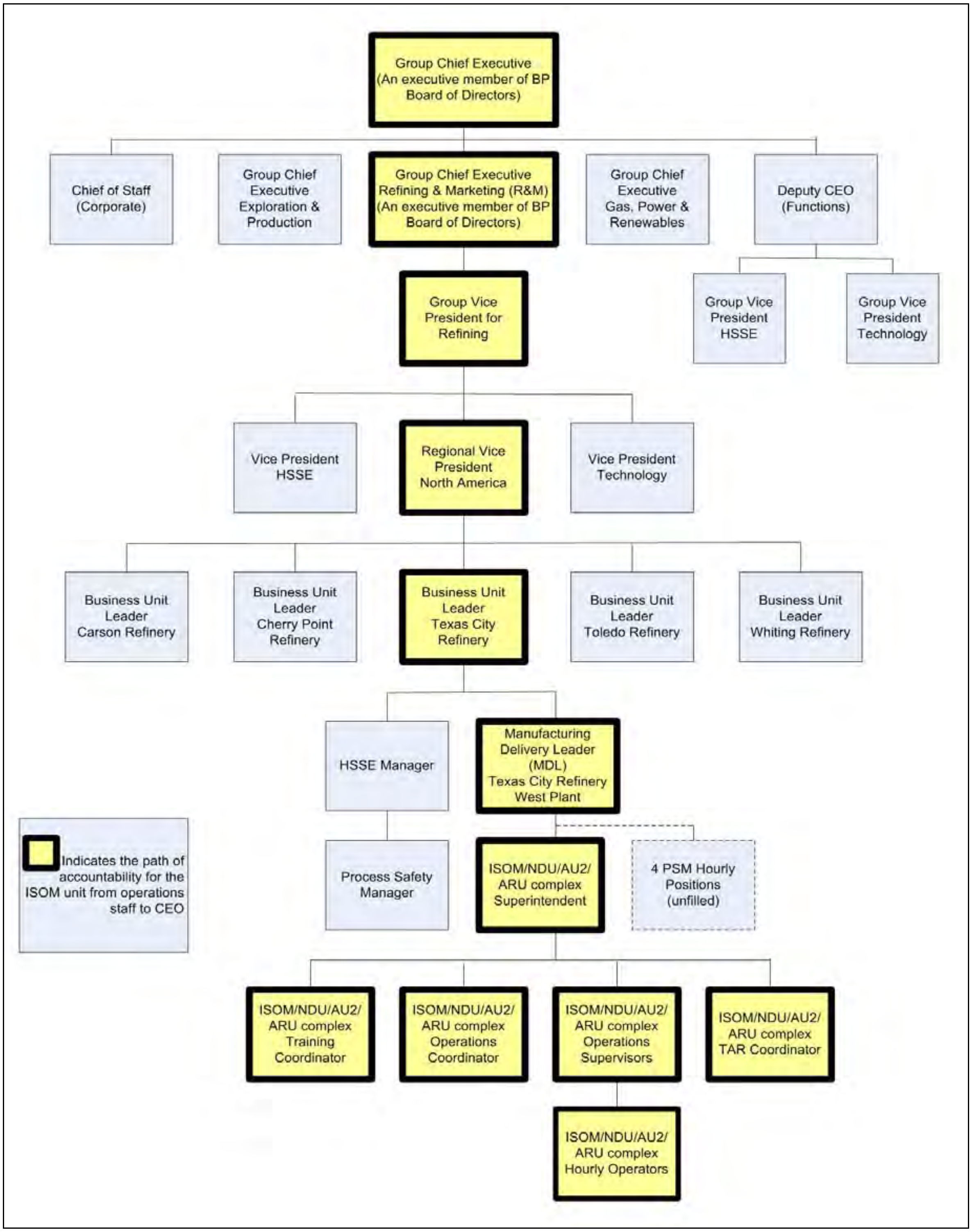

Figure 17. Simplified organizational chart of BP at the time of the March 23, 2005 incident. Some positions are not included

Although the GHSER policy required Business Unit Leaders to send annual performance assurance reports to the Group Chief Executive, the practice evolved to send the report only to the staff of the Group Vice President (VP) for refining. The staff aggregated each submission with the other refinery reports and submitted that document to the Refining and Marketing (R&M) managers, who, in turn, compiled a report for the Group Chief Executive. Additionally, the staff of the Group VP of Refining would aggregate the various segment reports into one group-wide report for the Environment and Ethics Assurance Committee of the Board of Directors.

Serious safety failures were not communicated in the compiled reports. For example, the "2004 R&M Segment Risks and Opportunities" report to the Group Chief Executive states that there were "real advancements in improving Segment wide HSSE [Health, Safety, Security & Environment] performance in 2004," but failed to mention the three major incidents and three fatalities in Texas City that year.

The GHSER expectations encompassed both personal safety and some process safety elements, however, GHSER reporting requirements focused on personal safety. Under GHSER, the BP R&M segment, including oil refining, required the reporting of fatalities, days away from work cases, recordable injuries,[143] and illnesses. Other data such as oil spills and chemical releases were also reported.[144] The GHSER policy did not require R&M reporting of explicit process safety performance indicators.[145]

[143] OSHA's Recordable Occupational Injury and Illness Incidence Rate is normalized to allow for comparisons across workplaces and industries. The rate is calculated as the number of recordable incidents for each 100 full-time employees per year, based on 2,000 hours worked per employee per year. OSHA's Recordable Injury Rate does not include fatalities.

[144] The reporting requirements for spills and chemical releases, while having process safety implications, were defined with thresholds relevant to environmental releases. For example, an oil spill was defined as greater than one barrel and a chemical release was limited to those reportable to local agencies, which, under US regulations, would typically be an environmental agency. Additionally, the oil spills metric was placed in the "environmentally sound operations" category of the group metrics.

[145] The UK Health and Safety Executive defines process safety performance indicators as typically both leading and lagging metrics that can provide up-to-date assurance that process plant major hazards are under control. Examples of PSM indicators include the resolution rate of PSM action items, the number of process safety near-miss incidents, or the percentage of instruments and equipment tested by the target date (HSE, 2006a).

9.3.3 Group Major Hazard Safety Standard

BP Group issued a "Process Safety/Integrity Management" standard in May 2001. This standard outlined BP's minimum requirements to "prevent the occurrence of, or minimize the consequences of, catastrophic releases of hazardous materials and to assure facilities are designed, constructed, operated and maintained in a safe fashion using appropriate codes and standards." The standard highlighted eight GHSER elements: hazard evaluation, MOC, mechanical integrity, protective systems, competent personnel, incident investigation, emergency response, and performance management and assurance, and provided guidance to meet the requirements of these elements. The BP Texas City refinery reviewed the Group standard and determined that the site's existing PSM program covered the standard's elements and that no changes were needed.

9.3.4 BP Management Framework

In 2003, BP issued "Management Framework," a document that addresses company governance issues brought about by rapid growth and consolidation of different management cultures due to mergers and acquisitions in the late 1990s. The framework describes BP's corporate governance system, which is based on three primary foundations: 1) BP operations are divided into business units that operate in a decentralized manner and rely on individual business unit leaders to run them and deliver performance; 2) BP Group (e.g., corporate) provides support for the business units through a variety of functions, networks, and peer groups; and 3) individual performance contracts are used to motivate people. The "Management Framework" was revised in 2004 to give more scope and authority to the Group functions, and to clarify BP management framework, goals, and processes.

9.3.4.1 Delegation of Authorities and Responsibilities

BP, a public company, is owned by its shareholders. Annually, these shareholders elect a Board of Directors and delegate authority to them for direction and oversight of the company's businesses. The

Board of Directors, comprised of both BP executives and outside directors, establishes goals, makes broad policy decisions, and monitors the Group Chief Executive's performance, but does not manage the day-to-day operations of the company.

The Group Chief Executive (Figure 17) is given the authority and responsibility by the Board to manage BP's businesses, subject to certain limitations. The limitations pertaining to safety are quite general: they require the Group Chief Executive to consider the effect on long-term shareholder value of the health, safety, and environmental consequences of any actions taken, and prohibit any employee from substituting his own risk preferences for those of the shareholders. The Group Chief Executive, under the "Management Framework," delegates these responsibilities to the executive officers who manage the Group functions, and to the chief executives of BP's three operating business segments, Exploration and Production; Refining and Marketing; and Gas, Power and Renewables.

Assurance that delegated activities are being effectively performed is determined primarily through monitoring, which is by direct inspection, routine and non-routine reports, or audits. Performance contracts are also used to measure key results and milestones, and play an integral part in determining annual bonuses. The Baker Panel noted that "BP regards performance contracts as an essential component in delegating commitments for BP's annual plans to individual leaders" (Baker, et al., 2007, pg. 28).

9.3.4.2 Role of HSSE in the *Management Framework*

The "Management Framework" specifies that only a limited number of HSSE activities are centralized under the HSSE Group function. These centralized activities include creating the GHSER policy, auditing HSSE matters, managing group crises, managing relationships with HSE regulators and government agencies, supporting mergers and acquisitions, and analyzing and using HSSE data. All other HSSE activities are delegated to the business segments: Exploration and Production; Refining and Marketing; and Gas, Power and Renewables.

9.3.4.3 HSE Impacts on Business Segment Management Strategies

The BP "Management Framework" also outlines the overall strategy and sub-strategies used to manage BP's business segments. One sub-strategy had major impacts on the Texas City refinery:

> While acknowledging that refining segment had grown considerably in the past few years due to acquisitions and that it could generate high returns, a sub-strategy was to limit the amount of capital allocated in the Refining SPU due to its 'volatility'.

This sub-strategy would make it more difficult for the Texas City refinery to get the capital it needed to repair its aging infrastructure (Section 9.4.17).

9.3.5 Texas City Process Safety Group

The PSM group at the Texas City refinery, part of the HSSE department at the time of the incident, was responsible for overseeing the implementation of process safety. The group had a manager and four process safety coordinators. The PSM group led all unit process hazard analyses and facility siting studies, and oversaw the MOC system for the 1,500 to 2,000 changes made annually. It also conducted PSSRs of major capital projects following turnarounds, coordinated PSM audits, and determined which incidents were investigated under PSM.

The process safety group developed and tracked process safety performance, but unlike the OSHA injury rate, the PSM metrics did not drive site performance. The PSM key performance indicators (KPIs), which included PSM action item closure, equipment inspections, and relief valve testing, were not incorporated into the GHSER metrics, the plant performance contract, personal performance contracts, or bonus programs. The PSM group planned to track safe operating limit exceedances, but this was not yet being done at the time of the 2005 incident.

9.3.6 Other Factors Impacting BP's Safety Management

Other factors, such as BP's performance contracts, incentive programs, behavioral safety initiatives, and responses to industry benchmarking, reflected a lack of focus on PSM and major accident prevention.

9.3.6.1 Performance Contracts

BP incorporated the Refining and Marketing GHSER performance targets in performance contracts with business units and personal contracts with Group and business unit leadership. The performance contracts were used to evaluate personnel and impacted managers' compensation. The contracts consisted of weighted metrics for categories such as financial performance, plant reliability, and safety. The largest percentage of the weighting was in financial outcome and cost reduction. The safety metrics included fatalities, days away from work case rate, recordable injuries, and vehicle accidents; process safety metrics were not included. HSE metrics typically accounted for less than 20 percent of the total weighting in the performance contracts.

9.3.6.2 Incentive Programs

BP Group implemented an incentive program based on performance metrics, the Variable Pay Plan (VPP), which was in place at the Texas City refinery for several years prior to the ISOM incident. Payouts under the VPP were approved by the refining executive managers in London. "Cost leadership" categories accounted for 50 percent and safety metrics for 10 percent of the total bonus. For the 2003-2004 period, the single safety metric for the VPP bonus was the OSHA Recordable Injury Rate[146].

9.3.6.3 Behavioral Safety

A central component of the BP Texas City approach to safety was its behavioral programs, which had been in effect in some form since 1997. The program, based on observations of BP workers and

[146] The OSHA recordable injury rate is the annual number of injuries and illnesses per 100 full-time workers. The OSHA injury rate, which excludes fatalities, is a normalized rate that is used for comparison across industries.

contractors engaged in work tasks, was designed to provide immediate feedback about observed hazards and activities that did not conform to refinery safety policies.

In a 2001 presentation, “Texas City Refinery Safety Challenge,” BP Texas City managers stated that the site required significant improvement in performance or a worker would be killed in the next three to four years. The presentation asserted that unsafe acts were the cause of 90 percent of the injuries at the refinery and called for increased worker participation in the behavioral safety program.

A new behavior initiative in 2004 significantly expanded the program budget and resulted in new behavior safety training for nearly all BP Texas City employees. In 2004, 48,000 safety observations were reported under this new program. This behavior-based program did not typically examine safety systems, management activities, or any process safety-related activities.

9.3.6.4 Industry Benchmarking

BP Group and Texas City managers’ priorities were greatly influenced by industry benchmarking of Solomon Associates, a firm that provides performance analysis and benchmarking services. Solomon benchmarking is widely used in the US oil refining industry to compare refinery performance in a wide variety of categories. Solomon data are presented as efficiency targets, allowing comparisons to peer refineries of a similar type, complexity, or locality.

Solomon performance measures include operating cost, refinery utilization, mechanical availability, energy efficiency, personnel staffing, and specific process unit categories. The BP Texas City refinery used the Solomon benchmarking data to analyze its competitive position and make resource allocation decisions. BP Texas City also used the Solomon data to establish its own performance metrics, and incorporated Solomon benchmarking data into its analytical reports, performance contracts, and plant goals. Solomon does not benchmark any specific process safety-related metrics.

9.3.7 Summary

BP's approach to safety largely focused on personal safety rather than on addressing major hazards. BP Group and the Texas City officials almost exclusively focused on, measured, and rewarded reductions in injury rates and days away from work rather than the improved performance of its process safety systems. BP had process safety systems in place in its Group management system and at Texas City, yet in the wake of the merger with Amoco, the resulting organizational changes to safety management led to a de-emphasis of major accident prevention.

BP and the U.K. Health and Safety Executive concluded from their Grangemouth investigations that preventing major accidents requires a specific focus on process safety. BP Group leaders communicated the lessons to the business units, but did not ensure that needed changes were made.

9.4 Ineffective BP Response to Reports of Serious Safety Problems 2002-2005

9.4.1 2002 Study Provides Warnings of Impending Major Site Incident

The new director of BP's South Houston Integrated Site (consisting of five area BP businesses, including the Texas City site) observed in 2002 that the Texas City refinery infrastructure and equipment were "in complete decline."[147] In consultation with London managers, the director ordered a study that looked at

[147] Interview of the former Texas City Site Director, October 12, 2006. The Site Director led five BP Houston area businesses that included the Texas City site, referred to as the South Houston Integrated Site (SHIS). The Texas City site comprised the oil refinery and the chemical plant. The South Houston site was reorganized in spring 2004 with the sale of some chemical assets and the Site Director became the Business Unit Leader for the Texas City site. During the period of the SHIS, the Texas City refinery had a separate Business Unit Leader who reported to both the Site Director and BP Global Executive management.

mechanical integrity, training, safety, and economic opportunities.[148] The study, which was shared with London executives, concluded that mechanical integrity was one of the biggest problems.[149]

The study stated that its findings were "urgent and far-reaching with important implications for the site, including the integrity of the on-going site operations," and warned about vulnerability in both the process units and infrastructure.[150] It indicated that "there were serious concerns about the potential for a major site incident due to the large number of hydrocarbon releases (over 80 in the 2000-2001 period)."[151] The study also found that many inspections were overdue,[152] and that "known reliability issues," including instrumentation, needed to be addressed. [153]

The study concluded that these problems were site-wide and that the Texas City refinery needed to focus on improving operational basics such as reliability, integrity, and maintenance management. The study found the refinery was in the lowest quartile of the 2000 Solomon index for reliability and ranked near the bottom among BP refineries. The leadership culture at Texas City was described in the study as "can do" accompanied by a "can't finish" approach to making needed changes.

The study recommended "a major overhaul of the 'basics'" including addressing issues such as vulnerability and cultural change.[154] While the study recognized mechanical integrity problems with both the infrastructure and process units, it specifically recommended increases in maintenance spending of $235 million, mostly to address the infrastructure problems at the Texas City refinery. The study did not

[148] "Good Practice Sharing Assessment," BP South Houston, August 2002. The 2002 study was referred as the "Veba" study because it was similar to the comprehensive analysis conducted for the German Veba Corporation that BP had recently acquired.

[149] "Good Practice Sharing Assessment," BP South Houston, Final Report, August 2002.

[150] In the "Veba" study, process units were referred to as "inside the battery limits," or ISBL. The infrastructure, including storage tanks, utilities, and docks, were referred to as "outside the battery limits." or OSBL.

[151] "Good Practice Sharing Assessment," BP South Houston, Final Report, August 2002.

[152] Ibid.

[153] Ibid.

[154] Ibid.

propose specific funds for identified problems with process units. A study recommendation proposed conducting a site-wide study to determine process unit requirements, but this was not done.

The study recommended improving the competency of operators and supervisors and defining process unit operating envelopes[155] and near-miss reporting around those envelopes to establish an operating "reliability culture."[156] The study found high levels of overtime and absenteeism resulting from BP's reduced staffing levels and called for applying MOC safety reviews to people and organizational changes. The study concluded that personal safety performance at Texas City refinery was excellent, but there were deficiencies with process safety elements such as mechanical integrity, training, leadership, and MOC.

The serious safety problems found in the 2002 study were not adequately corrected, and many played a role in the 2005 disaster.

9.4.2 Study Follow-up: Lack of Investment Compromised Safety

The BP Group Refining VP suggested a follow-up inquiry asking, "How has [South Houston] gotten into such a poor state?"[157] This follow-up report, the "Texas City Refinery Retrospective Analysis," issued later in 2002, had the objective of determining why Texas City refinery performance had deteriorated. The analysis concluded that "the current integrity and reliability issues at TCR [Texas City Refinery] are clearly linked to the reduction in maintenance spending over the last decade."[158] Capital spending was reduced 84 percent from 1992 to 2000. The analysis found "a consistent and significant reduction" in fixed costs[159] at the refinery between 1992 and 1999, when fixed costs were reduced 52 percent, and the

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[155] Operating envelopes were similar to safe operating limits, but also addressed environmental and economic factors. BP had implemented a computerized operating envelope program designed to increase oversight over process operations and critical parameters. The BP operating envelope program is discussed in Section 3.9.

[156] "Good Practice Sharing Assessment," BP South Houston, Final Report, August 2002.

[157] Email "S. Houston," August 16, 2002

[158] "Texas City Refinery Retrospective Analysis," October 28, 2002.

[159] BP defined fixed cash costs as costs that did not vary with production rates such as compensation, training costs, and routine maintenance.

report highlighted a 25 percent budget cut targeted in 1999-2000 in the wake of the BP and Amoco merger[160] (Appendix D). During the same period in the 1990s, total maintenance spending[161] was reduced 41 percent.

Identified spending increases from 2000 to 2002 were "primarily budget overruns resulting from fire-fighting unplanned events,"[162] and new energy and environmental projects.[163] For capital expenditures that addressed HSE and safe operation of the plant, funds were cut 78 percent from 1992-2002. The analysis stated that from 1992 to 2002 "the [Texas City] Refinery has consistently remained in the lowest percentile grouping for Operational Availability against Solomon benchmarks."[164] The analysis concluded that the budget cuts did not consider the specific maintenance needs of the Texas City refinery: "The prevailing culture at the Texas City refinery was to accept cost reductions without challenge and not to raise concerns when operational integrity was compromised."[165]

9.4.3 1999 – 2000 Significant Budget Cuts

The 2002 study identified a 25 percent cut in fixed cash costs targeted in 1999-2000. In 1999, the BP Group Chief Executive outlined his strategies and goals for newly merged company, with the target of "reduc[ing] business unit cash costs for the year 2001 by at least 25 percent from year 1998 levels."[166] He also set out three year targets to cut $1.4 billion from R&M worldwide.

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[160] "Texas City Refinery Retrospective Analysis," October 28, 2002.

[161] In the 2002 Texas City Refinery Retrospective Analysis, total maintenance included routine maintenance fixed cash costs, turnaround spending, HSE Capex (capital expenditure needed to meet internal and external safety standards) and Sustaining Capex (capital expenditure needed to safely maintain and operate the plant).

[162] An example of "fire fighting unplanned events" was piping or equipment failure that required unit shutdown and repair.

[163] "Texas City Refinery Retrospective Analysis," October 28, 2002.

[164] Ibid.

[165] Ibid.

[166] Email "Message from Site Leadership," July 15, 1999.

In 1999, the BP Group Chief Executive of R&M told the refining executive committee about the 25 percent cut, and said that the target was a directive more than a loose target. One refinery Business Unit Leader considered the 25 percent reduction to be unsafe because it came on top of years of budget cuts in the 1990s; he refused to fully implement the target.

While some BP refinery leaders resisted the call for a 25 percent reduction in fixed costs, Texas City made serious cuts and came close to the 25 percent reduction target.[167] Its cost reduction strategy was to "aggressively drive costs out of the system at an accelerated pace relative to other refiners."[168] The strategy indicated that the cuts would be accomplished through destaffing, outsourcing, and eliminating unnecessary turnaround costs. Items cut included turnarounds; safety committee meetings; the central training organization; fire drills; maintenance, engineering, supervision, and inspection staff; plant maintenance; and training courses. Safety and maintenance expenditures were a significant portion of the cuts. The refinery's capital expenditures to maintain safe plant operation and to comply with HSE legal requirements were cut $33 million, or 45 percent, from 1998 to 1999.[169]

9.4.4 2002 Financial Crisis Mode

The 2002 study concluded a critical need for increased expenditures to address asset mechanical integrity problems at Texas City. Shortly after the study's release, however, BP refining leadership in London warned Business Unit Leaders to curb expenditures. In October 2002, the BP Group Refining VP sent a communication saying that the financial condition of refining was much worse than expected, and that from a financial perspective, refining was in a **"**crisis mode**."**[170] The Texas City West Plant[171] manager,

[167] "MPH TCBU Face to Face Presentation," July 16, 2002. The historical TCBU fixed cash costs (inflation adjusted) fell 23.2 percent from 1998 to 1999.

[168] Texas City Business Unit Strategy, July 12, 1999.

[169] Capital Plan Texas City Refinery – Technical Managers Network Kwinana, February 29, 2000.

[170] Email "GFO" from the Global VP for Refining, October 17, 2002.

[171] The ISOM unit where the March 23, 2005, incident occurred was in the Texas City West Plant.

while stating that safety should not be compromised, instructed supervisors to implement a number of expenditure cuts including no new training courses. During this same period, Texas City managers decided not to eliminate atmospheric blowdown systems.

9.4.5 2003 Maintenance Gap Assessment

In 2003, BP Texas City managers conducted a "Getting Maintenance and Reliability Right Gap Assessment," which concluded that maintenance and mechanical integrity problems persisted at Texas City. While plant infrastructure reliability scores were among the lowest, the assessment concluded that scores were "fairly low for all areas."[172] The assessment found that most areas had insufficient resources to conduct the needed root cause failure analysis (RCFA) for equipment problems, and that most action items were "not implemented because of budget constraints."[173] Many manufacturing areas scored low on most elements of the assessment. The Texas City West Plant scored below the minimum acceptable performance in 22 of 24 elements. For turnarounds, the West Plant representatives concluded that "cost cutting measures [have] intervened with the group's work to get things right. Team feels that no one provides/communicates rationale to cut costs. Usually reliability improvements are cut."[174] Two major accidents in 2004-2005 (both in the West Plant of the refinery—the UU4 in 2004 and ISOM in 2005) occurred in part because needed maintenance was identified, but not performed during turnarounds.

9.4.6 The SHIFT Program

The BP Texas City refinery responded to the integrity problems with programs that largely addressed infrastructure rather than process unit vulnerability. In 2003, the site leadership implemented the South Houston Infrastructure for Tomorrow (SHIFT) program in response to the 2002 study recommendations.

[172] BP South Houston "Getting Maintenance and Reliability Right" (GMRR) 2003 Gap Assessment Results," September, 2003.

[173] Ibid.

[174] Ibid.

A presentation by Texas City managers summed up the budget-cutting history that led to the SHIFT program:[175]

> "Pre-2002: How did we get into our intolerable risk situation with the Infrastructure assets?
>
> - Culture
> - Money."

The presentation noted that the infrastructure problem took years to develop and would take significant time to fix. The presentation's five-year, $150 million proposal included details on the Piping Integrity Project (PIP), which mostly addressed infrastructure needs, and would cost $50 million. The presentation included no specific requests for addressing the process unit integrity issues identified in the 2002 study, but did identify the critical nature of the situation, stating that the SHIFT program must be **"**the last disaster recovery project at Texas City."[176]

9.4.7 2003 GHSER Audit—"The condition of infrastructure and assets is poor"

The September 2003 GHSER audit found that "the units and staff are actively managing infrastructure risks but the current condition of the infrastructure and assets is poor at [the] Texas City refinery." One of the most problematic gaps identified was that a "checkbook mentality" still existed throughout most of the Texas City site, which "limits HSE and general performance." The "checkbook mentality" meant that the budgets were not large enough to address identified risks, and that only the money on hand would be spent, rather than increasing the budget. The audit team was concerned about "insufficient resources to

[175] Shift Program Review, August 19, 2003.
[176] Ibid.

achieve all commitments and goals." The South Houston site leader was disappointed about the audit findings because "many things have shown up before."[177]

An overall conclusion of the audit was that a coordinated self-monitoring process was not evident; therefore, management was leaving some risks unaddressed. The audit found that "HSE actions items are allowed to become past due and remain in that status without intervention." While the audit found that personal and behavioral safety were strong, the audit's first recommendation was that BP South Houston "break the cycle in the culture that tolerates HSE exceptions":[178]

- BPSH (BP South Houston) must establish the standard that makes overdue HSE actions and/or critical maintenance inspections or unaddressed major risks unacceptable to the Leadership Team.
- Accept zero for exceptions to BP (Group and local) HSE standards.
- Embed PSM Systems at all sites.

The audit identified some additional significant risks. In particular, the risk of the refinery "operating envelope" that needed to be addressed,[179] a site-wide risk assessment process that was not robust enough, and deficient training in most areas.[180]

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[177] The follow-up action items from the 2003 GHSER audit ineffectively addressed the identified Texas City safety deficiencies. For example, the response to the finding on the poor condition of the assets stated that measures had been taken in the 2005 budget—over one year after the audit. Only a small portion of the capital allocated to the listed infrastructure projects had been spent prior to 2005. Although the Veba analysis and other reviews identified integrity problems with both process units and infrastructure, Texas City increased spending in 2005 mostly on infrastructure projects (docks, utilities, tank farm, etc.).

[178] In response to the recommendation that the culture tolerated HSE exceptions, BP implemented the 2004 Compliance Delivery Process (CDP). CDP focused largely on worker behavior and personnel safety, even though the audit recommendation focused primarily on the need for management to address major risks and fully implement PSM systems.

[179] As Section 4.10 discusses, the operating envelope program was not fully functional at the time of the ISOM incident and managers were not alerted about envelope exceedances.

[180] The 2003 GHSER recommendation concerning training improvements and the implementation of a risk identification process was not addressed at the time of the 2005 ISOM incident.

The poor condition of the refinery, inadequate training, inadequate PSM implementation, and the need for leadership to set an example and eliminate exceptions to HSE standards were all findings of the audit and causally related to the ISOM incident.

9.4.8 1,000 Day Goals

In response to the financial and safety challenges facing South Houston, the site leader developed 1,000 day goals in fall 2003 that measured site-specific performance. The 1,000 day goals addressed safety, economic performance, reliability, and employee satisfaction; the consequence of failing to change in these areas was described as losing the "license to operate."[181] The 1,000 day goals for safety included recordable injury frequency (RIF) and HSE action item closure (a PSM action item closure goal was not added until early 2005 and had not been reported prior to the ISOM incident). The goals also measured indicators such as Solomon mechanical availability, cash delivery, and environmental reports; the goal to reduce maintenance spending 25 percent was added in 2004. The 1,000 day goals reflected the continued focus by site leadership on personal safety and cost-cutting rather than on process safety.

9.4.9 The Texas City Repositioning Project

During 2003 the plant was continually pressured to reduce expenditures. Plant officials initiated the Texas City Refinery Repositioning Project in August 2003 at the request of BP Group Refining management, who told the refinery that it had not made a contribution of profit proportionate to its capital consumption.[182] The goal of the project was to improve the refinery's competitive position over a 10 year period by focusing on efficiency changes to the refinery's asset configuration and technology. The team looked for significant changes that included over $30 million in capital expenditure cuts and $140 million

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[181] "1,000 Day Goals -- What is this about?" document, 2003.

[182] The project team, led by BP personnel outside the refinery, found that the refinery contributed only 10 percent of the Global refining profits while consuming 18 percent of capital expenditure needed to meet environmental and safety compliance. The Texas City refinery faced additional challenges due to its unique complexity and interconnectedness. Management stated that the refinery was the most complex in the world by a factor of two.

increase in annual operating profit. The Reposition Project and the SHIFT program reflected the persistent competing pressures on the Texas City refinery to cut capital expenditures, increase efficiency, and spend needed funds to address asset vulnerability. Those pressures would intensify with the major accidents that occurred in 2004.

9.4.10 The Ultraformer #4 (UU4) Incident

Mechanical integrity problems previously identified in the 2002 study and the 2003 GHSER audit were warnings of the likelihood of a major accident. In March 2004, a furnace outlet pipe ruptured and resulted in fire that caused $30 million in damage. Texas City managers investigated and prepared an HRO analysis of the accident to identify the underlying cultural issues.[183] They found that in 2003 an inspector recommended examining the furnace outlet piping, but this was not done. Prior to the 2004 incident, thinning pipe discovered in the outlet piping toward the end of a turnaround was not repaired, and, after the unit was started up, a hydrocarbon release from the thinning pipe caused a major fire. One key finding of the investigation was that "[w]e have created an environment where people 'justify putting off repairs to the future.'"[184] The BP investigation team, which included the refinery maintenance manager and the West Plant Manufacturing Delivery Leader (MDL), also found an "intimidation to meet schedule and budget" when the discovery of the unsafe pipe conflicted with the schedule to start up UU4. The team summarized its conclusions:

- **"**The incentives used in this workplace may encourage hiding mistakes."
- "We work under pressures that lead us to miss or ignore early indicators of potential problems."
- "Bad news is not encouraged." [185]

[183] HRO Learning's from UU4 Incident Investigation – "Deep Dive."
[184] Ibid.
[185] Ibid.

These findings are similar to the BP Group refining group-wide HRO study and the West Plant team's 2003 Maintenance Gap Assessment that identified budget and scheduling pressures that impacted reliability. In both the UU4 and ISOM incidents, required maintenance was not conducted prior to startup. In the ISOM incident, three pieces of equipment necessary for safe operation – the raffinate splitter tower's level transmitter, sight glass, and pressure valve – were identified by managers as malfunctioning prior to the startup, but were not repaired.

9.4.11 Ultraformer #3 (UU3) Incident

In September 2004, three workers in the UU3 unit were burned, two fatally, with hot water and steam during the opening of a pipe flange. The workers believed the pump system was isolated and were unaware that a check valve was concealing hazardous energy from a leaking discharge block valve. The absence of a bleed valve between the check and block valve did not allow the workers to verify whether the piping was isolated, depressured, and safe to open.

The investigation recommendations included revising plant lockout/tagout procedures and engineering specifications to ensure a means to verify the safe energy state between a check and block valve, such as installing bleeder valves. In a review of the incident, the Texas City site leader stated that the pump was locked out based on established procedures and that work rules had not been violated. In 2004, two of the three major accidents were process safety-related.[186] Taken as a whole, the incidents revealed a serious decline in process safety and management system performance at the BP Texas City refinery.

[186] The September 2004 UU3 incident is process safety-related. While the application of OSHA's PSM standard is limited to listed highly hazardous chemicals, industry safety guidelines have a broader application of PSM that encompasses all process hazards and hazardous materials. The CCPS defines PSM as "the application of management principles and systems to the identification, understanding and control of process hazards to prevent process- related injuries and incidents" (CCPS, 1995b). CCPS also states that line and equipment opening and lockout/tagout are a type of hazardous maintenance work that can lead to hazardous releases and are addressed by process safety guidelines (CCPS, 1995a.).

9.4.12 2004 BP Group GHSER Audit Review—"Systemic Underlying Issues"

In 2004 the BP Internal Audit Group in London reviewed GHSER audits for 2003 and found a number of serious safety deficiencies common throughout the corporation. The BP auditors reviewed the 35 audits, including South Houston.[187] The audit report, released in March 2004, found significant common deficiencies:[188]

- widespread tolerance of non-compliance with basic HSE rules;
- poor implementation of HSE management systems, reducing the effectiveness and efficiency of activities to manage HSE risks and deliver sustainable performance;
- lack of leadership competence and understanding to effectively manage all aspects of HSE;
- insufficient monitoring of key HSE processes to provide management visibility and confidence in management's ability to deliver as required and [implement] necessary interventions.

Leadership and accountability were the most common problem, which was found in 28 business units. The report stated that there was a lack of leadership focus on closing action items from audits and other safety reviews, as well as a backlog of maintenance items. The report also found that leadership was not "reinforcing expectations through their own behaviors."

The report found that risk assessment was "often incomplete," that business units did not understand or address major hazards, and that competency in risk and hazard assessment was poor.

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[187] The audits were conducted over a mix of BP Global businesses including R&M and Exploration & Production.
[188] Internal audit, "2003 GHSER Audits—Summary of Findings," March 2004.

The report found that MOC was poorly defined; in particular, a lack of clarity on what constitutes a change in areas such as temporary modifications and organizational change. In addition, the report concluded that MOC systems lacked staff competency, rigorous application, and monitoring.

The report stated there were “poor processes” to disseminate lessons learned. While the BP Group HSE organization distributed information on incidents, business units lacked effective processes for assessing the implications or taking action to prevent a similar occurrence. This finding is significant because the HSE Grangemouth report concluded that BP’s organizational structure impaired the corporation’s ability to learn from incidents and prevent major accidents. The internal audit findings are evidence that the conclusions from the 2003 Grangemouth report had not been effectively addressed.

9.4.13 BP’s Golden Rules of Safety

In response to the 2004 report on GHSER audits, the BP Group Chief Executive of R&M directed Business Unit Leaders to focus on reviews of control of work[189] and vehicle safety to ensure compliance with the Golden Rules of Safety.[190] The Golden Rules addressed primarily personal safety issues related to work activities such as working at heights, lifting operations, and entering confined spaces. Although MOC is one element of the Golden Rules, process safety was not specifically addressed.

In May 2004, the Texas City site performed a “Control of Work Review,” which revealed deficiencies in compliance with the Golden Rules. The three primary areas of concern were risk assessment, use of nitrogen, and lifting operations. The review found that plant personnel generally complied with policies and procedures, but there was variability among operating units and tasks performed. The report concluded that site leadership needed to communicate to the workforce “that productivity and progress in other areas is not acceptable if it comes at the cost of noncompliance with HSE policies and procedures.”

[189] “Control of work” addresses workplace hazards and how to manage them safely.

[190] Email from BP Global Chief Executive of R&M to the Group R&M Leadership, dated March 30, 2004.

The Texas City site's response to the "Control of Work Review," which occurred after the two major accidents in spring 2004,[191] focused on ensuring compliance with safety rules. The response stated that the review findings support "our objective to change our culture to have zero tolerance for willful non-compliance to our safety policies and procedures." The report indicated that "accepting personal risk" and noncompliance based on lack of education on the rules would end. To correct the problem of non-compliance, Texas City managers implemented the "Compliance Delivery Process" and "Just Culture" policies. "Compliance Delivery" focused on adherence to site rules and holding the workforce accountable. The purpose of the "Just Culture" policy was to ensure that management administered appropriate disciplinary action for rule violations. The "Just Culture" policy indicated that willful breaches of rules, but not genuine mistakes, would be punished. The Texas City Business Unit Leader announced that he was implementing an educational initiative and accelerated the use of punishment to create a "culture of discipline."[192]

These initiatives failed to address process safety requirements or management system deficiencies identified in the GHSER audits, mechanical integrity reviews, and the 2004 incident investigation reports. BP Group executive leadership met with the Texas City Business Unit Leader several times in 2004 and approved the focus on personal safety. The BP Group Chief Executive for R&M visited the Texas City refinery in July 2004 to review progress toward the 1,000-day goals and improved safety performance. In a presentation to the Chief Executive during the visit, the site reported a "best ever" recordable injury rate. The action plan for improvement was to "aggressively pursue Control of Work Audit learnings," but there was no action plan for the deteriorating Texas City process safety performance.

[191] The two major incidents in spring 2004 included the March UU4 incident and in May 2004, a contractor died from a fall inside a tower during a turnaround in the AU2 unit.

[192] June 27, 2004, email from the Texas City Business Unit Leader to the BP Global North American VP for Refining and the Global Chief Executive for R&M; Subject: Control of Work Response.

In the July 2004 presentation, Texas City managers also spoke to the ongoing need to address the site's reliability and mechanical integrity issues and financial pressures. The presentation suggested that a number of unplanned events in the process units led to the refinery being behind target for reliability, citing the UU4 fire and other outages and shutdowns. The presentation stated that "poorly directed historic investment and costly configuration yield middle of the pack returns." The conclusion was that Texas City was not returning a profit commensurate with its needs for capital, despite record profits at the refinery. The presentation indicated that a new 1,000-day goal had been added to reduce maintenance expenditures to "close the 25 percent gap in maintenance spending" identified from Solomon benchmarking.[193]

The BP Texas City refinery increased total maintenance spending in 2003-2004 by 33 percent[194]; however, a significant portion of the increase was a result of unplanned shutdowns and mechanical failures. In the July 2004 presentation to the R&M Chief Executive, Texas City leadership said that "integrity issues had been costly," specifically identifying an increase in turnaround costs.[195] In 2004, BP Texas City experienced a number of unplanned shutdowns and repairs due to mechanical integrity failures[196]: the UU4 piping failure incident resulted in $30 million in damage, and while the Texas City refinery West Plant leader proposed improving reliability performance to avoid "fix it when it fails" maintenance, integrity problems persisted. In addition, the ISOM area superintendent was reporting "numerous equipment failures" that resulted in budget overruns.[197]

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[193] According to Solomon benchmarking, the BP Texas City refinery was spending more on maintenance than other refineries of similar size and complexity. The 1,000 Day Goal was established to close that gap.

[194] Email "Texas City Spend," May 12, 2005.

[195] Texas City Refinery Business Review, (Global Chief Executive for R&M) Site Visit Pre-read, July 12, 2004.

[196] TC Site Availability, June 2004.

[197] Email "Budget Outlook for 2004," from ISOM area superintendent.

At the July 2004 presentation, the Texas City leadership also presented a compliance strategy to the R&M Chief Executive that stated:[198]

> In the face of increasing expectations and costly regulations, we are choosing to rely wherever possible on more people-dependent and operational controls rather than preferentially opting for new hardware. This strategy, while reducing capital consumption, can increase risk to compliance and operating expenses through placing greater demands on work processes and staff to operate within the shrinking margin for human error. Therefore to succeed, this strategy will require us to invest in our 'human infrastructure' and in compliance management processes, systems and tolls to support capital investment that is unavoidable.

The document identified that "Compliance Delivery" was the process that Texas City managers designated to deliver the referenced workforce education and compliance activities. The chosen strategy states that this approach is less costly than relying on new hardware or engineering controls but has greater risks from lack of compliance or incidents.

The aftermath of the UU3 incident resulted in additional scrutiny from Group executives and urgency for the Texas City refinery to improve safety performance. As a result, the Texas City Business Unit Leader met with the R&M Chief Executive and the Senior Executive Team in October 2004 to view the presentation, "Texas City Site Safety Transformation," which recounted the fatal incidents with pictures of the deceased. Although two of the three major accidents in 2004 were process safety-related, the safety problems were described primarily in terms of casual compliance and personal risk tolerance. Again, "Compliance Delivery" and "Just Culture" were the programs cited as addressing the problems; the proposed action plans did not focus on management system issues or process safety concerns.

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[198] Texas City HSE Compliance, July 7, 2004.

9.4.14 Process Safety Performance Declines Further in 2004

In August 2004, the Texas City Process Safety Manager gave a presentation to plant managers that identified serious problems with process safety performance. The presentation showed that Texas City 2004 year-to-date accounted for $136 million, or over 90 percent, of the total BP Group refining process safety losses; and over five years, accounted for 45 percent of total process safety refining losses.[199] The presentation noted that PSM was easy to ignore because although the incidents were high-consequence, they were infrequent. The presentation addressed the HRO concept of the importance of mindfulness and preoccupation with failure; the conclusion was that the infrequency of PSM incidents can lead to a loss of urgency or lack of attention to prevention.

In September 2004, the site PSM manager told the Business Unit Leader that Texas City had received poor scores in second quarter concerning PSM metrics such as action item completion (63 percent).[200] This information had been communicated in a PSM presentation at the September 2004 BP Group refining leadership meeting where the Texas City refinery was categorized as high risk.[201] A key message in the presentation was that process safety was just as important as personal safety. The presentation summarized BP's refinery PSM incident history, indicating that the "depth and rigor of investigations" was not always sufficient to identify root causes. In March 2005, before the ISOM incident, the Texas City operations manager communicated to a Group refining executive that the PSM action item closure status for fourth quarter 2004 was a concern; as a result, PSM closure was added to the site's 1,000 Day Goals.

[199] TC-PSC Chair Selection, August 1, 2004.

[200] Email "Process Safety discussion at GRL meeting on 14th September."

[201] GRL Process Safety Session Presentation, September 2004.

Texas City had serious problems with unresolved PSM action items. Target closure rate was 90 percent, but in 2004 was only 79 percent, down from 95 percent in 2002. The PSM manager indicated that the closure rate had fallen since the metric was removed from the formula in 2003 for calculating bonuses. At the end of 2004, the Texas City site had closed only 33 percent of its PSM incident investigation action items; the ISOM unit closed 31 percent. Only 40 percent of the PSM business plan milestones were completed in 2004.

Additionally, the findings from the 2004 PSM audit (Section 8.3.4) revealed poor PSM performance in a number of areas categorized as high priority, especially in mechanical integrity, training, process safety information, and MOC. Texas City refinery's mechanical availability[202] worsened from 2002 to 2004.[203] During this same period, loss of containment incidents, a process safety metric tracked but not managed by BP, increased 52 percent from 399 to 607 per year (Baker, et al., 2007).

9.4.15 "Texas City is not a Safe Place to Work"

Fatalities, major accidents, and PSM data showed that Texas City process safety performance was deteriorating in 2004. Plant leadership held a safety meeting in November 2004 for all site supervisors detailing the plant's deadly 30-year history. The presentation, "Safety Reality," was intended as a wakeup call to site supervisors that the plant needed a safety transformation, and included a slide entitled "Texas City is not a safe place to work." Also included were videos and slides of the history of major accidents and fatalities at Texas City, including photos of the 23 workers killed at the site since 1974.

The "Safety Reality" presentation concluded that safety success begins with compliance, and that the site needed to get much better at controlling process safety risks and eliminating risk tolerance. Even though

[202] Mechanical availability measures the time available for processing minus downtime for maintenance.

[203] The 2004 Solomon metrics for mechanical availability put Texas City refinery performance at the bottom of 29 Gulf Coast refineries and 79 of 82 refineries nationally.

two major accidents in 2004 and many of those in the previous 30 years were process safety-related, the action items in the presentation emphasized following work rules.

9.4.16 Telos Survey

In late 2004, the Texas City site performed a safety culture assessment. The survey was initiated by the Business Unit Leader to determine the "brutal facts" concerning "our management systems, our site leadership, our site cultures, and our behaviors for safety and integrity management." Researchers from safety culture consultant the Telos Group surveyed 1,080 employees and interviewed 112. The interviewees included members of the leadership team and 69 supervisors. The assessment team issued a report with recommendations (Telos Report) in January 2005, which was "embraced"[204] by the site leadership team. The Telos report provided insight into the organizational and cultural conditions at the Texas City refinery before the ISOM explosion.

The report revealed that Texas City had a severely flawed safety culture and organizational deficiencies that preceded the ISOM incident. The report findings include:[205]

- Production pressures impact managers "where it appears as though they must compromise safety."
- "Production and budget compliance gets recognized and rewarded before anything else at Texas City."
- "The pressure for production, time pressure, and understaffing are the major causes of accidents at Texas City."

[204] "Telos Perspective and Recommendations," part of the *Telos Report*, January 21, 2005.
[205] "Executive Summary of Report Findings," part of the *Telos Report*, January 21, 2005.

- "The quantity and quality of training at Texas City is inadequate…compromising other protection-critical competence."
- "Many [people] reported errors due to a lack of time for job analysis, lack of adequate staffing, a lack of supervisor staffing, or a lack of resident knowledge of the unit in the supervisory staff."
- Many employees also reported "feeling blamed when they had gotten hurt or they felt investigations were too quick to stop at operator error as the root cause." There was a "culture of casual compliance."
- Serious hazards in the operating units from a number of mechanical integrity issues: "There is an exceptional degree of fear of catastrophic incidents at Texas City."
- Leadership turnover and organizational transition; the creation and dismantling of the South Houston site "made management of protection very difficult."
- The strong safety commitment by the Business Unit Leader "is undermined by the lack of resources to address severe hazards that persist," and "for most people, there are many unsafe conditions that prove cost cutting and production are more important than protection. Poor equipment conditions are made worse in the view of many people by a lack of resources for inspection, auditing, training, and staffing for anything besides 'normal operating conditions.'"
- Texas City was at a "high risk" for the "check the box" mentality. This included going through the motions of checking boxes and inattention to the risk after the check-off. "Critical events, (breaches, failures or breakdowns of a critical control measure) are generally not attended to."

Texas City managers asked the safety culture consultants who authored the Telos report to comment on what made safety protection particularly difficult for Texas City. The consultants noted that they had never seen such a history of leadership changes and reorganizations over such a short period that resulted in a lack of organizational stability.[206] Initiatives to implement safety changes were as short-lived as the leadership, and they had never seen such "intensity of worry" about the occurrence of catastrophic events by those "closest to the valve." At Texas City, workers perceived the managers as "too worried about seat belts" and too little about the danger of catastrophic accidents. Individual safety "was more closely managed because it 'counted' for or against managers on their current watch (along with budgets) and that it was more acceptable to avoid costs related to integrity management because the consequences might occur later, on someone else's watch."

The Telos consultants also noted that concern about equipment conditions was expressed not only by BP personnel, but "strongly expressed by senior members" of the contracting community who "pointed out many specific hazards in the work environment that would not be found at other area plants." The consultants concluded that the tolerance of "these kind of risks must contribute to the tolerance of risks you see in individual behavior."

The refinery leadership team reviewed the Telos report and accepted the findings. The Business Unit Leader said that "seeing the 'brutal facts' so clearly defined was hard to digest, including the concern around the conflict between production and safety. The evidence was strong and clear and I accept my responsibility for the results."[207] The Business Unit Leader summarized results of the report on March 17, 2005, for all plant supervisors. The summary stated that the site had gotten off to good start in 2005 with safety performance that "may be the best ever," adding that Texas City had had "the best profitability ever in its history last year" with over $1 billion in profit—"more than any other refinery in the BP system."

Despite the stark findings of safety failures reflected in site performance and the Telos assessment, BP management persisted in believing that the personal injury rates reflected total safety performance. The Business Unit Leader stated that BP Group refinery executive leadership was "very complimentary" of

[206] Telos memo, "What makes protection particularly difficult for BP Texas City?"
[207] Email "Update from [Business Unit Leader]," March 17, 2005.

progress and had “high praise” for the site’s auditing process and “our Safety Culture response efforts.” The Business Unit Leader also applauded the safety efforts of the supervisors “that prompted [the Group VP for refining] to raise our VPP [bonus program] scores and improve all of our payouts!” The BP Group HSE VP for Refining stated that the executive leadership had considered further intervention at Texas City, but did not act because the personal injury rates had improved. Focus on injury rates at all levels of BP management helped mask severe shortcomings in process safety. In this regard, the lessons of the Grangemouth report were not learned or acted upon.

9.4.17 2005 Budget Cuts

In late 2004, BP Group refining leadership ordered a 25 percent budget reduction “challenge” for 2005. The Texas City Business Unit Leader asked for more funds based on the conditions of the Texas City plant, but the Group refining managers did not, at first, agree to his request. Initial budget documents for 2005 reflect a proposed 25 percent cutback in capital expenditures, including on compliance, HSE, and capital expenditures needed to maintain safe plant operations.[208] The Texas City Business Unit Leader told the Group refining executives that the 25 percent cut was too deep, and argued for restoration of the HSE and maintenance-related capital to sustain existing assets in the 2005 budget. The Business Unit Leader was able to negotiate a restoration of less than half the 25 percent cut; however, he indicated that the news of the budget cut negatively affected workforce morale and the belief that the BP Group and Texas City managers were sincere about culture change.

In February 2005, the BP Group VP and the North American VP for Refining visited Houston, where refinery managers presented details about safety transformation efforts, the Telos cultural assessment, and “Safety Reality” slides. The presentation listed the major Telos findings, including concern about the condition of the refinery, budget cuts, pressure for production overshadowing safety, and inadequate

[208] TCR Update – 2005 HSE Capex, August 24, 2004; Email “Texas City Capex Reduction Proposal” from the Business Unit Leader, 11-5-04.

training. Also discussed were the three fatalities in 2004 and the poor PSM action item closure rate. The site's mechanical availability was graded a "D," with little or no progress due to unplanned events such as the UU4 fire. Also identified were the initial 25 percent capital expenditure cuts in the 2005 budget and the amount restored. Texas City managers proposed, in the presentation, that the executive leaders restore an additional $41 million of the 2005 cuts in the 2006 budget.[209]

9.4.18 2005 Key Risk—"Texas City kills someone"

The 2005 Texas City HSSE Business Plan[210] warned that the refinery likely would "kill someone in the next 12-18 months." This fear of a fatality was also expressed in early 2005 by the HSE manager: "I truly believe that we are on the verge of something bigger happening,"[211] referring to a catastrophic incident. Another key safety risk in the 2005 HSSE Business Plan was that the site was "not reporting all incidents in fear of consequences." PSM gaps identified by the plan included "funding and compliance," and deficiency in the quality and consistency of the PSM action items. The plan's 2005 PSM key risks included mechanical integrity, inspection of equipment including safety critical instruments, and competency levels for operators and supervisors. Deficiencies in all these areas contributed to the ISOM incident.

9.4.19 Summary

Beginning in 2002, BP Group and Texas City managers received numerous warning signals about a possible major catastrophe at Texas City. In particular, managers received warnings about serious deficiencies regarding the mechanical integrity of aging equipment, process safety, and the negative safety impacts of budget cuts and production pressures.

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[209] "Texas City Site Update, A Brief Update for Mike Hoffman – February 15, 2005."

[210] HSSE '05 Business Plan, March 15, 2005. HSSE is Health, Safety, Security, and the Environment.

[211] Email from the HSSE manager, February 20, 2005.

However, BP Group oversight and Texas City management focused on personal safety rather than on process safety and preventing catastrophic incidents. Financial and personal safety metrics largely drove BP Group and Texas City performance, to the point that BP managers increased performance site bonuses even in the face of the three fatalities in 2004. Except for the 1,000 day goals, site business contracts, manager performance contracts, and VPP bonus metrics were unchanged as a result of the 2004 fatalities.

10.0 ANALYSIS OF BP'S SAFETY CULTURE

The BP Texas City tragedy is an accident with organizational causes embedded in the refinery's culture. The CSB investigation found that organizational causes linked the numerous safety system failures that extended beyond the ISOM unit. The organizational causes of the March 23, 2005, ISOM explosion are

- BP Texas City lacked a reporting and learning culture. Reporting bad news was not encouraged, and often Texas City managers did not effectively investigate incidents or take appropriate corrective action.
- BP Group lacked focus on controlling major hazard risk. BP management paid attention to, measured, and rewarded personal safety rather than process safety.
- BP Group and Texas City managers provided ineffective leadership and oversight. BP management did not implement adequate safety oversight, provide needed human and economic resources, or consistently model adherence to safety rules and procedures.
- BP Group and Texas City did not effectively evaluate the safety implications of major organizational, personnel, and policy changes.

10.1 Lack of Reporting, Learning Culture

Studies of major hazard accidents conclude that knowledge of safety failures leading to an incident typically resides in the organization, but that decision-makers either were unaware of or did not act on the warnings (Hopkins, 2000). CCPS' "Guidelines for Investigating Chemical Process Incidents" (1992a) notes that almost all serious accidents are typically foreshadowed by earlier warning signs such as near-misses and similar events. James Reason, an authority on the organizational causes of accidents, explains that an effective safety culture avoids incidents by being informed (Reason, 1997). Collecting appropriate information, assessing vital signs, and communicating lessons and knowledge of hazards are characteristics of an effective safety culture. An informed culture includes two essential elements: reporting and learning, and in such a culture, managers have up-to-date knowledge about the "human, technical, organizational and environmental factors that determine the safety of the system as a whole" (Reason, 1997). BP Texas City did not have effective reporting and learning cultures where previous incidents and near-misses could serve as learning opportunities to avoid catastrophic incidents.

10.1.1 Reporting Culture

An informed culture must first be a reporting culture where personnel are willing to inform managers about errors, incidents, near-misses, and other safety concerns. The key issue is not if the organization has established a reporting mechanism, but rather if the safety information is actually reported (Hopkins, 2005). Reporting errors and near-misses requires an atmosphere of trust, where personnel are encouraged to come forward and organizations promptly respond in a meaningful way (Reason, 1997). This atmosphere of trust requires a "just culture" where those who report are protected and punishment is reserved for reckless non-compliance or other egregious behavior (Reason, 1997). While an atmosphere conducive to reporting can be challenging to establish, it is easy to destroy (Weike et al., 2001).

10.1.1.1 BP Texas City Reporting

The BP Texas City site had a number of reporting programs, yet serious near-misses and other critical events were often unreported. In the eight previous ISOM blowdown system incidents, three were not reported in any BP database, five were reported as environmental releases, and only two were investigated as safety incidents. In the five years prior to the 2005 disaster, over three-quarters of the raffinate splitter tower startups' level ran above the range of the level transmitter and in nearly half, the level was out of range for more than one hour. These operating deviations were not reported by operations personnel or reviewed in the computerized history by Texas City managers. During the March 2005 ISOM startup, the operating deviations were more serious in degree but similar in kind to past startups.

Yet the operating envelope program designed to capture and report excursions from safe operating limits was not fully functional and did not capture high distillation tower level events in the ISOM to alert managers to the deviations.

Other methods to communicate safety information also failed to provide critical data. Logbooks, incident databases, and fire and environmental reports typically provided little detail or analysis of the events. The maintenance work order system was primarily an accounting program that lacked crucial information about work order history, the cause of failures, and whether equipment was successfully repaired. Logbooks also provided little detail on equipment repairs.

BP Texas City managers did not effectively encourage the reporting of incidents; they failed to create an atmosphere of trust and prompt response to reports. Among the safety key risks identified in the 2005 HSSE Business Plan, issued prior to the disaster, was that the "site [was] not reporting all incidents in fear of consequences." The maintenance manager said that Texas City "has a ways to go to becoming a learning culture and away from a punitive culture."[212] The Telos report found that personnel felt blamed when injured at work and "investigations were too quick to stop at operator error as the root cause."

Lack of meaningful response to reports discourages reporting. Texas City had a poor PSM incident investigation action item completion rate: only 33 percent were resolved at the end of 2004. The Telos report cited many stories of dangerous conditions persisting despite being pointed out to leadership, because "the unit cannot come down now." A 2001 safety assessment found "no accountability for timely completion and communication of reports."

[212] Email from the Texas City Maintenance Manager, January 19, 2005.

10.1.1.2 BP Group Reporting

Responsibility for a lack of a reporting culture extended to BP Group. The three major accidents at the Texas City refinery were not mentioned in the GHSER reports sent to Group executives and the BP Board of Directors. A 2004 BP Group HRO survey found that across all business units "mistakes may be held against people."[213] A 2002 BP Group analysis, "Learning from Tragedy," concluded that the "quality of investigation and reporting varies considerably and quality of evidence gathering [is] sometimes questionable."

10.1.2 Learning Culture

BP Group and Texas City lacked a learning culture. A learning culture ensures that reports of incidents and safety information are analyzed and lessons learned effectively communicated, and that prompt corrective action is taken (Hopkins, 2005). BP Group and Texas City had serious deficiencies in these areas:

- Management failed to adequately investigate previous incidents that revealed the serious hazards of atmospheric blowdown systems in the ISOM, and other process units and failed to take corrective action.

- Managers did not act on findings from previous reports, such as more training for operators and supervisors, use of control board simulators, and use of fully functional operating envelopes.

- Reports of malfunctioning instrumentation were not acted on and instrument checks were not completed prior to the ISOM startup.

[213] Aggregate HRO Survey Results, June 2004.

- BP did not monitor recurring instrument malfunctions, such as the high level switch on the raffinate splitter tower and the blowdown drum, for trends or failure analysis.
- A BP Group 2002 report on the Group Fatal Accident Investigation Process found that “critical factors and hence root causes [were] not identified” and that “corrective actions [were]sometimes vague and impractical.”
- The 2003 South Houston GHSER audit found that “a coordinated, self monitoring and self assessment process is not evident throughout the organization.”
- The 2004 GHSER assessment graded Texas City as “poor” because investigation information was not analyzed to monitor trends and develop prevention programs. The assessment found little use of the GHSER audit/assessment results to drive plant goals.
- The 2004 Group Internal Audit report found poor plant monitoring and lessons learned processes at 35 BP Group business units: “[i]nformation on incidents is circulated from Group HSE. Some entities do not have robust processes for assessing the implications of these and initiating actions to manage their risks of a similar occurrence.”

The lack of a learning and a reporting culture was also revealed in BP’s ineffective response to the important lessons from the Grangemouth report. Many of the organizational failures in the ISOM incident involved issues that were also key lessons from Grangemouth. The U.K. Health and Safety Executive concluded that BP lacked “a strong, consistent overall strategy for major accident prevention,” which was a barrier to learning from previous incidents. Failure to effectively act on those lessons set the stage for the ISOM incident. BP Group lacked an effective program to ensure that lessons from internal and external incidents were acted upon corporate-wide.

10.2 Lack of Focus on Controlling Major Hazard Risk

BP did not effectively assess and control the risks of major hazards at Texas City. In the events leading up to the ISOM incident, managers and operators lacked an understanding of major hazard risk: 1) the blowdown system had not been replaced, despite previous serious incident reports and policies that required converting it to a flare; 2) occupied trailers were placed dangerously close to running process units because the siting analysis failed to identify the risks; 3) non-essential personnel were not evacuated despite the hazards posed by ISOM unit startup; 4) the startup was authorized despite having inadequate staffing, malfunctioning instruments and equipment, and without a pre-startup safety review (PSSR); and 5) during the startup, no qualified supervision was present and procedures were not followed as had been the practice for some time.

Audits and assessments concluded that Texas City had serious deficiencies in identifying and controlling major risks. The 2003 GHSER audit found that “the practice of risk identification and the development of mitigation plans are not evident across the site.” The 2004 GHSER assessment concluded that “no formal system exists for identifying high level risks.” The 2005 Telos assessment found that “critical events, (breaches, failures, or breakdowns of a critical control measure) are generally not attended to.” Safety risks revealed by the 2004 fatalities and property damage, the falling PSM action item closure rate, and poor equipment integrity were not perceived as requiring more serious intervention.

Similar risk awareness deficiencies were found at business units across the corporation. BP Group’s 2004 Internal Audit report found that business unit managers’ risk management processes did not understand or control major hazards, nor were these processes used to drive priorities or allocate resources. Moreover, BP business unit managers had poor competency in risk and hazard management.

10.2.1 Focus on personal safety rather than process safety

BP Group executives used personal safety metrics to drive safety performance. A key lesson from the

U.K. Health and Safety Executive Grangemouth report is that BP needed a specific focus on KPIs for process safety because personal safety metrics are not a reliable measure of the risk for a major accident. BP did not adequately implement these lessons in its Group safety management or at Texas City, and, in fact, paid most attention to, measured, and rewarded personal safety performance rather than process safety. Personal safety metrics were the exclusive measures in the GHSER policy, HSE assurance reports, business and personal contracts, incentive programs, and plant goals. Personal safety metrics are important to track low-consequence, high-probability incidents, but are not a good indicator of process safety performance. As process safety expert Trevor Kletz notes, “The lost time rate is not a measure of process safety”[214] (Kletz, 2003). An emphasis on personal safety statistics can lead companies to lose sight of deteriorating process safety performance (Hopkins, 2000).

Process safety KPIs provide important information on the effectiveness of safety systems, and an early warning of impending catastrophic failure (HSE, 2006a). The sole use of lagging safety indicators, such as injury rates or numbers of incidents, has been described as trying to drive down the road looking only in the rear view mirror---it tells you where you have been but not where you are headed. Process safety good practice guidelines recommend using both leading and lagging indicators for process safety. Leading indicators provide a check of system functioning—whether needed actions have been taken, such as equipment inspections completed by the target date or PSM action item closure. Lagging indicators, such as near-misses, provide evidence that a key outcome has failed or not met its objective. “Active monitoring” of both leading and lagging indicators is important to the health of process safety systems (HSE 2006a).

[214] Kletz (2001) also writes that “a low lost-time accident rate is no indication that the process safety is under control, as most accidents are simple mechanical ones, such as falls. In many of the accidents described in this book the companies concerned had very low lost-time accident rates. This introduced a feeling of complacency, a feeling that safety was well managed”.

10.2.2 "Check the box"

Rather than ensuring actual control of major hazards, BP Texas City managers relied on an ineffective compliance-based system that emphasized completing paperwork. The Telos assessment found that Texas City had a "check the box" tendency of going through the motions with safety procedures; once an item had been checked off it was forgotten. The CSB found numerous instances of the "check the box" tendency in the events prior to the ISOM incident. For example, the siting analysis of trailer placement near the ISOM blowdown drum was checked off, but no significant hazard analysis had been performed, hazard of overfilling the raffinate splitter tower was checked off as not being a credible scenario, critical steps in the startup procedure were checked off but not completed, and an outdated version of the ISOM startup procedure was checked as being up-to-date.

10.2.3 Oversimplification

In response to the safety problems at Texas City, BP Group and local managers oversimplified the risks and failed to address serious hazards. Oversimplification means evidence of some risks is disregarded or deemphasized while attention is given to a handful of others[215] (hazard and operability study, or HAZOP Weak et al., 2001). The reluctance to simplify is a characteristic of HROs in high-risk operations such as nuclear plants, aircraft carriers, and air traffic control, as HROs want to see the whole picture and address all serious hazards (Weick et al., 2001). An example of oversimplification in the space shuttle Columbia report was the focus on ascent risk rather than the threat of foam strikes to the shuttle (CAIB, 2003). An example of oversimplification in the ISOM incident was that Texas City managers focused primarily on infrastructure[216] integrity rather than on the poor condition of the process units. Four major incidents where mechanical integrity played a role in 2004-2005 occurred in the process units—UU4, ISOM, RHU,

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[215] Weick and Sutcliffe further state that HROs manage the unexpected by a reluctance to simplify: "HROs take deliberate steps to create more complete and nuanced pictures. They simplify less and see more."

[216] The infrastructure includes refinery storage tanks, utilities, and docks.

CFHU.[217] As the 2003 GHSER audit notes, BP Texas City was managing the infrastructure problems; however, process unit hazards were not adequately addressed.

BP Group executives oversimplified their response to the serious safety deficiencies identified in the internal audit review of common findings in the GHSER audits of 35 business units. The R&M Chief Executive determined that the corporate response would focus on compliance, one of four key common flaws found across BP's businesses. The response directing the R&M segment to focus on compliance emphasized worker behavior. Other deficiencies identified in the internal audit included lack of HSE leadership and poor implementation of HSE management systems; however, these problems were not addressed. This narrow compliance focus at Texas City allowed PSM performance to further deteriorate, setting the stage for the ISOM incident. The BP focus on personal safety and worker behavior was another example of oversimplification.

10.2.4 Ineffective corporate leadership and oversight

BP Group managers failed to provide effective leadership and oversight to control major accident risk. According to Hopkins, top management's actions and what they paid attention to, measure, and allocate resources for is what drives organizational culture (Hopkins, 2005). Examples of deficient leadership at Texas City included managers not following or ensuring enforcement of policies and procedures, responding ineffectively to a series of reports detailing critical process safety problems, and focusing on budget cutting goals that compromised safety.

Texas City managers did not model safe practices, and in the incidents and critical events prior to the ISOM incident, deviated from numerous safety policies and procedures. Managers did not complete the study of the ISOM pressure relief system that had been required by the OSHA process safety regulations for many years. Contrary to BP policy (Section 5.5.4), the ISOM blowdown drum was not replaced with a

[217] CFHU is the Cat Feed Hydrotreating Unit.

flare system, nor was the siting of the trailers effectively managed. A PSSR that would have required non-essential personnel to be removed from the ISOM unit and surrounding areas prior to startup was not conducted. Numerous procedures and forms were checked off, but the safety critical tasks were not performed or reviewed. Finally, the startup lacked the presence of qualified supervisory oversight or technically trained personnel despite being required by BP policy.

The 2003 GHSER audit emphasized that the Texas City senior managers must “break the culture that tolerated HSE exceptions,” citing overdue action items and maintenance inspections and unaddressed major risks. The 2004 BP audit of 35 business units found a lack of leadership competence and understanding of HSE, and that “leadership was not reinforcing the [GHSER] expectations through their own behaviors.” The Telos authors concluded that management accepting risks, such as serious unaddressed hazards or deviations from safety procedures, can contribute to “the tolerance of risks you see in individual behavior.”

Budget cuts and production pressures seriously impacted safe operations at Texas City. Studies and assessments presented to BP Group managers linked the history of budget cuts to critical safety issues: “The current integrity and reliability issues at [Texas City] are clearly linked to the reduction in maintenance spending over the last decade.”[218] Budget cuts also impaired training, operations staffing levels, and mechanical integrity. Budget pressures affected the decision not to replace the ISOM blowdown system on several occasions. BP’s assessment of the 2004 UU4 accident, as well as events leading to the ISOM incident, show that safety critical repairs were not conducted because there “was no time” left in the turnaround schedule.

The 2005 Telos assessment indicated that while senior managers showed a strong safety commitment, it was “contradicted by the lack of resources, action or clear plans to address severe hazards that persist. For

[218] Texas City Refinery Retrospective Analysis, October 28, 2002.

most people there are many unsafe conditions that prove cost cutting and production are more important than protection."

The BP Chief Executive and the BP Board of Directors did not exercise effective safety oversight. Decisions to cut budgets were made at the highest levels of the BP Group despite serious safety deficiencies at Texas City. BP executives directed Texas City to cut capital expenditures in the 2005 budget by an additional 25 percent despite three major accidents and fatalities at the refinery in 2004.

The CCPS, of which BP is a member, developed 12 essential process safety management elements in 1992. The first element is accountability. CCPS highlights the "management dilemma" of "production versus process safety" (CCPS, 1992b). The guidelines emphasize that to resolve this dilemma, process safety systems "must be adequately resourced and properly financed. This can only occur through top management commitment to the process safety program." (CCPS, 1992b). Due to BP's decentralized structure of safety management, organizational safety and process safety management were largely delegated to the business unit level, with no effective oversight at the executive or board level to address major accident risk.

The Financial Reporting Council (FRC), the U.K.'s independent regulator for corporate reporting and governance, has adopted "Internal Control: Guidance for Directors on the Combined Code," commonly referred to as the "Turnbull guidance." The Turnbull guidance recommends that U.K. boards maintain a system of internal risk control that includes HSE, and that that boards review the system's effectiveness annually: "The review should cover all material controls, including financial, operational and compliance controls and risk management systems" (FRC, 2005).

The UK Health and Safety Executive's report on the accidents at the BP Grangemouth refinery also addresses the importance of board safety oversight. One of the report's "wider messages for industry" states that "[o]perators should give increased focus to major accident prevention in order to ensure serious business risk is controlled and to ensure effective Corporate Governance.” The Health and Safety Executive specifically uses the BP Grangemouth incident to address the responsibilities of board members for major accident prevention:

> The Turnbull report states that directors should, at least annually, review systems of control including risk management, financial, operational and compliance controls that are the key to the fulfillment of the company’s business objectives.
>
> The HSE has prepared guidance for directors in order to help them ensure that the health and safety risks arising from their organizations activities are properly managed. Directors should be fully aware of their corporate responsibilities in relation to the control of major accident hazards. Failure by a corporate body and the directors of a company to adequately manage health and safety can result in prosecution of the company and the individual directors responsible.
>
> As previously stated the underlying causes of major accidents (technical, managerial and human factors) are well established from analysis of hundreds of major accidents worldwide. Directors have a duty to manage these known factors to prevent major accidents (HSE, 2003).

The above quotation from the guidance ”Directors Responsibilities for Health and Safety”, as referenced in the Grangemouth Report, states that “[t]he board needs to ensure that it is kept informed of, and alert to, relevant health and safety risk management issues. The UK Health and Safety Commission (HSC) recommends that boards appoint one of their number to be the ‘heath and safety director’”[219] (HSC, 2002). Additionally, the guidance recommends that boards of directors review their heath and safety performance annually, ensure that management systems provide effective monitoring and reporting, and ensure that the health and safety implications of all their decisions are addressed.

[219] This guidance is published by the Health and Safety Executive (HSE); the Health and Safety Commission is the politically appointed governing body of the HSE.

The Baker Panel Report concluded that BP's Board of Directors had not ensured, as a best practice, effective implementation of PSM. Safety culture expert James Reason emphasizes the importance of designating corporate boards of directors' responsibility for organizational safety and major hazard risk control. BP has a board Ethics and Environment Assurance committee that monitors safety issues; however, no board member has designated health and safety leadership responsibilities or a background in refinery operations or process safety.

10.3 Safety Implications of Organizational Change

Although the BP HSE management policy, GHSER, required that organizational changes be managed to ensure continued safe operations, these policies and procedures were generally not followed. Poorly managed corporate mergers, leadership and organizational changes, and budget cuts greatly increased the risk of catastrophic incidents.

10.3.1 BP mergers

In 1998, BP had one refinery in North America. In early 1999, BP merged with Amoco and then acquired ARCO in 2000. BP emerged with five refineries in North America, four of which had been just acquired through mergers. BP replaced the centralized HSE management systems of Amoco and Arco with a decentralized HSE management system.

The effect of decentralizing HSE in the new organization resulted in a loss of focus on process safety. In an article on the potential impacts of mergers on PSM, process safety expert Jack Philley explains, "The balance point between minimum compliance and PSM optimization is dictated by corporate culture and upper management standards. Downsizing and reorganization can result in a shift more toward the minimum compliance approach. This shift can result in a decrease in internal PSM monitoring, auditing, and continuous improvement activity" (Philley, 2002).

10.3.2 Organizational Changes at Texas City

After the Amoco merger, Texas City underwent a complex series of leadership and organizational changes that were only informally assessed for their impact on safety and health. In 1999, Texas City was a separate business unit run by a business unit leader. In 2001, the refinery became part of the BP South Houston complex along with four BP chemical plants (Figure 18; Appendix D). From then until 2004, the safety, environmental, and process safety departments were combined and operated as a shared services group servicing multiple facilities. This resulted in the process safety group not reporting directly to each site's business unit leader; instead they reported to the Star Site's Shared Services Group (Appendix D.2).

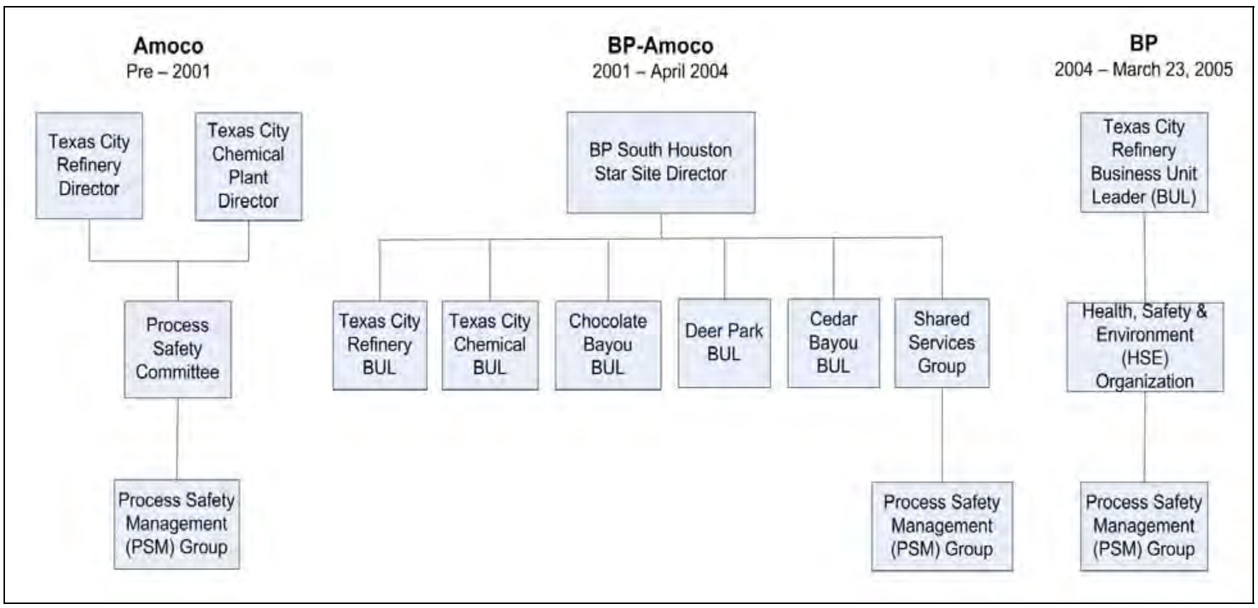

Figure 18. Organizational changes affecting the Texas City refinery

After the BP South Houston complex was formed, a series of leadership changes occurred. First, the refinery business unit leader became the BP South Houston director and the Texas City refinery was run by an operations manager. In 2002, the director was replaced and later that year the operations manager left. He was replaced by a refinery performance unit leader, who functioned basically as the business unit leader. The Baker Panel Report concluded that Texas City refinery senior leadership turnover had been high with nine plant managers since 1997; five from 2001 to 2003 (Baker, et al., 2007).

Additional organizational change occurred in 2003 and 2004 when BP issued its "Management Framework." The BP South Houston complex was dissolved, the director became the refinery Business Unit Leader, and the process safety department became part of the new HSSE department with a new manager.

The impact of these ineffectively managed organizational changes on process safety was summed up by the Telos study consultants. Weeks before the ISOM incident, when asked by the refinery leadership to explain what made safety protection particularly difficult for BP Texas City, the consultants responded:

> We have never seen an organization with such a history of leadership changes over such short period of time. Even if the rapid turnover of senior leadership were the norm elsewhere in the BP system, it seems to have a particularly strong effect at Texas City. Between the BP/Amoco mergers, then the BP turnover coupled with the difficulties of governance of an integrated site… there has been little organizational stability. This makes the management of protection very difficult.[220]

Additionally, BP's decentralized approach to safety led to a loss of focus on process safety. BP's new HSE policy, GSHER, while containing some management system elements, was not an effective PSM system. The centralized Process Safety group that was part of Amoco was disbanded and PSM functions were largely delegated to the business unit level. Some PSM activities were placed with the loosely organized Committee of Practice that represented all BP refineries, whose activity was largely limited to informally sharing best practices.

[220] Telos Group memo, "What makes protection particularly difficult for BP Texas City?"

The impact of these changes on the safety and health program at the Texas City refinery was only informally assessed. Discussions were held when leadership and organizational changes were made, but the MOC process was generally not used. Applying Jack Philley's general observations to Texas City, the impact of these changes reduced the capability to effectively manage the PSM program, lessened the motivation of employees, and tended to reduce the accountability of management (Philley, 2002).

10.3.3 Budget Cuts

BP audits, reviews, and correspondence show that budget-cutting and inadequate spending had impacted process safety at the Texas City refinery. Sections 3, 6, and 9 detail the spending and resource decisions that impaired process safety performance in operator training, board operator staffing, mechanical integrity and the decisions not to replace the blowdown drum in the ISOM unit. Philley warns that shifts in risk can occur during mergers: "If company A acquires an older plant from company B that has higher risk levels, it will take some time to upgrade the old plant up to the standards of the new owner. The risk reduction investment does not always receive the funding, priority, and resources needed. The result is that the risk exposure levels for Company A actually increase temporarily (or in some cases, permanently)" (Philley 2002). Reviewing the impacts of cost-cutting measures is especially important where, as at Texas City, there had been a history of budget cuts at an aging facility that had led to critical mechanical integrity problems. BP Texas City did not formally review the safety implications of policy changes such as cost-cutting strategy prior to making changes.

10.3.4 Good Practice Guidelines

The need to manage organizational change is recognized in good practice guidelines issued by CCPS (1992b); American Chemistry Council (CMA, 1998); the Health and Safety Executive (2003b); the Canadian Society for Chemical Engineering (2004); and Contra Costa County in California (1999). A recent U.S. survey by Keen, West, and Mannan (2002) showed, however, that organizational change was addressed in the MOC programs of only 44 percent of chemical processing companies. Kletz notes that companies may not be addressing the full range of organizational changes, and recommends that MOC programs assess the impact on safety and health of organizational changes resulting from outsourcing, major re-organizations following mergers or downsizing, and other high level changes (Kletz, 2003).

11.0 REGULATORY ANALYSIS

11.1 OSHA's Process Safety Management Regulation

11.1.1 Background Information

In 1990, the U. S. Congress responded to catastrophic accidents[221] in chemical facilities and refineries by including in amendments to the Clean Air Act a requirement that OSHA and EPA publish new regulations to prevent such accidents. The new regulations addressed prevention of low-frequency, high-consequence accidents. OSHA's regulation, "Process Safety Management of Highly Hazardous Chemicals," (29 CFR 1910.119) (PSM standard) became effective in May 1992. This standard contains broad requirements to implement management systems, identify and control hazards, and prevent "catastrophic releases of highly hazardous chemicals."

11.1.2 PSM Standard Elements

Several PSM elements are applicable to the disaster at BP Texas City. The BP Texas City ISOM unit was a covered process under the PSM rule, because the process contained over 10,000 pounds of flammable

[221] The catastrophic accidents included the 1984 toxic release in Bhopal, India, that resulted in several thousand known fatalities, and the 1989 explosion at the Phillips 66 petrochemical plant in Pasadena, Texas, that killed 23 and injured 130.

substances.[222],[223] These PSM elements include PHA, process safety information,[224] MOC, and mechanical integrity.[225]

The initial PHA and subsequent revalidations for the BP Texas City ISOM unit failed to identify the possible scenario of raffinate splitter tower overfill, leading to a liquid release from the blowdown drum (section 8.1). Therefore, the raffinate splitter instruments, such as the level transmitter, were not identified as critically important to prevent a catastrophic release, and were not placed on a priority schedule for maintenance and inspection.

An effective PHA depends on accurate information as the basis for analysis. Accurate information is also vital for inspecting, testing, and maintaining instruments. The PSM standard identifies specific information that must be maintained, including relief system design and basis, instrument data sheets, and documentation that equipment complies with recognized and accepted good industry practice.

Instrument technicians at BP Texas City did not have a current data sheet for the raffinate splitter level transmitter or testing procedures for the blowdown drum high level alarm. The ISOM unit pressure relief system design review was not completed and the blowdown drum did not comply with recognized good industry practice, as it was undersized.

[222] Applicability of the PSM rule is determined by whether the process contains in excess of the threshold quantity of listed highly hazardous chemicals.

[223] A flammable liquid is any liquid having a flashpoint below 100°F (37.8°C). A flammable gas is a gas at ambient temperature and pressure that forms a flammable mixture with air at a concentration of 13% by volume or less [29CFR 1910.1200 (A)].

[224] Process safety information is documentation needed to identify process hazards such as information related to process chemistry, safe upper and lower operating limits, technology, equipment, and design codes. The PSM standard requires covered employers to compile process safety information in conjunction with conducting a PHA.

[225] The other elements of the PSM Rule are contractor safety, PSSR, hot work permits, incident investigation, emergency planning and response, and compliance audits. The 13th "element" is mainly a requirement that maintaining trade secrecy not interfere with an employer's compliance with the other 12 elements.

11.1.2.1 Management of Change (MOC)

Mergers, reorganizations, staffing cuts and reassignments, budget cuts, and other policy changes impacted the effectiveness of BP Texas City safety systems. Audits and other assessments found that the MOC program ineffectively reviewed policy, organizational, and personnel changes.

The OSHA PSM standard requires that, at a minimum, a company's MOC policy apply to "process chemicals, technology, equipment, and procedures; and, changes to facilities…" Industry good practice guidelines recommend that MOC also apply to organizational, personnel, and policy changes that could affect process safety. OSHA does not require employers to evaluate these types of changes.

BP Texas City required that an MOC be initiated for changes to personnel, staffing and organization (Section 8.2). BP conducted an MOC analysis before placing additional duties on board operators but did not implement their findings effectively. However, BP did not formally review the safety impact of broader organizational and policy changes that potentially impacted process safety at the refinery, nor were they required to do so by the PSM standard. BP Texas City did not perform MOCs on budget cuts, staff reductions, and organizational changes that impaired process safety.

CCPS and the American Chemistry Council (ACC, formerly CMA)[226] publish guidelines for MOC programs. CCPS (1995b) recommends that MOC programs address organizational changes such as employee reassignment. The ACC guidelines for MOC warn that changes to the following can significantly impact process safety performance:

- staffing levels,
- major reorganizations,
- corporate acquisitions,

[226] The American Chemistry Council is a chemical industry trade association.

- changes in personnel, and
- policy changes (CMA, 1993).

Kletz reported on an incident that was similar to the March 23 explosion in which a distillation tower overfilled to a flare that failed and released liquid, causing a fire. According to Kletz, the immediate causes included failure to complete instrument repairs (the high level alarms did not activate); operator fatigue; and inadequate process knowledge. Kletz attributed the incident to changes in staffing levels and schedules, cutbacks, retirements, and internal reorganizations. He recommends "with changes to plants and processes, changes to organi[s]ation should be subjected to control by a system…which covers…approval by competent people"[227] (Kletz 2003).

The U.K. Health and Safety Executive published an information sheet in 2003 that provides guidance on managing the impact of organizational change on major hazards (HSE, 2003b). Among the types of changes recommended that managers address are mergers and acquisitions, downsizing, changes to key personnel, centralization and decentralization of functions, and changes at site and corporate levels. The document also includes a framework and methodology for managing and assessing the risk of such changes.

If BP had reviewed the safety implications of changes to personnel, policy, and organization, the March 23 disaster would have been less likely to occur. In addition, adoption of broader MOC requirements by OSHA would help companies like BP avoid catastrophic events.

11.1.2.2 Mechanical Integrity

The PSM standard requires procedures to maintain the integrity of process equipment. Poor testing, inspection, and maintenance of ISOM instrumentation (Section 7.0) were causal factors in the disaster.

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[227] For the sake of brevity, several other elements of an organizational change management system in Kletz's article are omitted here.

11.1.2.3 OSHA Enforcement at BP Texas City

After the March 23, 2005 incident OSHA conducted an inspection of the Texas City facility and identified over 300 egregious willful violations of OSHA standards, many of which were related to PSM non-compliance. BP was fined over 21 million dollars. Under the settlement agreement, BP agreed to abate all violations, pay the penalty and retain an outside PSM expert to conduct a refinery-wide comprehensive audit.

In the 20 years prior, OSHA records show at least 10 incidents at the site, resulting in 10 fatalities.[228] While three workers died in 2004, there were no planned inspections conducted that year. Prior to the March 23, 2005, incident, OSHA conducted one planned[229] PSM inspection of the Texas City facility in 1998. That planned inspection was related to a local emphasis program; all other inspections were unplanned--the result of an accident, complaint, referral from another agency, or an inspection of another company (such as a BP contractor). During the 20 year period, OSHA issued citations for three willful and 82 serious violations, resulting in proposed penalties of \$270,255, of which \$77,860 was collected.[230]

11.1.2.4 OSHA Enforcement History

A deadly explosion at the Phillips 66 plant in Pasadena, Texas, killed 23 in 1989. It occurred before the OSHA PSM standard was issued. OSHA investigated this accident and published a report to the President of the United States in 1990. In that report, OSHA identified several actions to prevent future incidents that, in OSHA's words "occur relatively infrequently, when they do occur, the injuries and fatalities that result can be catastrophic" (OSHA, 1990). The report recognized the importance of a different type of inspection priority system other than one based upon industry injury rates and proposed that "OSHA will

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[228] BP internal documents received by the CSB indicate 11 fatalities during the same 20-year period.

[229] Planned or programmed OSHA inspections of worksites have been scheduled based on national, regional or area plans, targeting programs, or special emphasis programs.

[230] These inspections and penalties do not include the inspection following the September 2004 incident that killed two. OSHA did not settle this inspection with BP until the conference following the March 23, 2005, incident.

revise its current system for setting agency priorities to identify and include the risk of catastrophic events in the petrochemical industry."

Prior to the Phillips disaster, OSHA conducted a Special Emphasis Program (SEP)[231] using a system safety approach to prevent accidents in the chemical manufacturing industry. OSHA conducted 40 ChemSEP inspections in 1985 and 1986. According to the final report reviewing the program, the valuable lesson learned by OSHA from these ChemSEP inspections is that an inspection process different from the agency's traditional approach of determining compliance with the safety and health standards is needed to address the identification and correction of potentially catastrophic situations. A comprehensive approach, which includes both physical conditions and management systems, is indicated (OSHA, 1987a).

11.1.2.5 Program Quality Verification (PQV) Inspections

The PSM standard is designed to prevent catastrophic accidents. OSHA's enforcement program for preventing these accidents requires planned, comprehensive compliance inspections in facilities with accident histories or other indications of risk for a catastrophe. In 1992, OSHA published the compliance directive[232] for the PSM standard, which states that "the primary enforcement model for the PSM standard shall be the PQV (Program Quality Verification) inspection" (OSHA Instruction CPL 02-02-045). Those inspections have three parts: determining if the elements of a PSM program are in place; evaluating if the programs comply with the requirements of the standard; and verifying compliance with the standard through interviews, data sampling, and field observations.

[231] SEPs are focused inspections aimed at specific hazards or industries and usually include a detailed inspection protocol.

[232] Compliance directives are the main method OSHA uses to communicate the targeting plans, inspection methods and compliance expectations to their Compliance Safety and Health Officers for enforcing a new regulation. The PSM Compliance Directive was updated in 1994.

11.1.2.6 PQV Inspection Targeting

In its report on the Phillips 66 explosion, OSHA concluded that the petrochemical industry had a lower accident frequency than the rest of manufacturing, when measured in traditional ways using the Total Reportable Incident Rate (TRIR)[233] and the Lost Time Injury Rate (LTIR). However, the Phillips 66 and BP Texas City explosions are examples of low-frequency, high-consequence catastrophic accidents. TRIR and LTIR do not effectively predict a facility's risk for a catastrophic event; therefore, inspection targeting should not rely on traditional injury data. OSHA also stated in its report that it will include the risk of catastrophic events in the petrochemical industry on setting agency priorities. The importance of targeting facilities with the potential for a disaster is underscored by the BP Texas City refinery's potential off-site consequences from a worst case chemical release. In its Risk Management Plan (RMP) submission to the EPA, BP defined the worst case as a release of hydrogen fluoride with a toxic endpoint of 25 miles; 550,000 people live within range of that toxic endpoint and could suffer "irreversible or other serious health effects" under the potential worst case release.[234]

The targeting process began with OSHA selecting industries (SIC codes) that had experienced the greatest number of accidents. Petroleum refining and seven chemical industry segments were on the original list, which OSHA had not updated prior to the incident.[235]

Although the PSM compliance directive requires each of the 10 OSHA regions to submit five candidate facilities for inspections each year, OSHA has conducted few planned PQV inspections. OSHA

[233] Prior to the March 23, 2005, explosion, the TRIR at BPTC was one-third the industry average, even though multiple fatalities had occurred in the year before the incident.

[234] BP Texas City Risk Management Plan, March 1, 2005.

[235] Within these industries, each regional office was to submit a list of five possible inspection targets within their region (from the over 2,800 U. S. facilities in these industries). Candidate facilities were to be selected based on several factors, including incident history, toxicity of chemicals onsite, and previous inspections. OSHA's Directorate of Compliance would determine the inspection goals and select the facilities to receive PQV inspections each year.

inspection data[236] reveals that federal OSHA conducted nine planned PQV inspections in targeted industries from 1995 to March 2005, while OSHA state plan jurisdictions conducted 48. Federal OSHA conducted no planned PQV inspections in oil refineries from 1995 to March 2005. All six planned PQV inspections in oil refineries were by state plan offices (Alaska, California, Nevada, Utah, and Wyoming.)

During the same period, federal OSHA conducted 77 unplanned PQV inspections[237] and state plans conducted 29. Unplanned inspections are typically narrower in scope, shorter, and limited to possible regulatory violations raised from accidents, complaints, or referrals from another regulatory agency.

OSHA's compliance directive states that "it is anticipated that PQV inspections will be highly resource-intensive." The directive describes a PQV inspection as "a large and complex undertaking" and states that a PQV inspection "is long-term, possibly several weeks or months." However five of the nine planned federal OSHA PQV inspections conducted lasted less than one month.

The National Transportation Safety Board (NTSB) found deficiencies in OSHA oversight of PSM-covered facilities. A 2001 railroad tank car unloading incident at the ATOFINA chemical plant in Riverview, Michigan, killed three workers and forced the evacuation of 2,000 residents. The 2002 NTSB investigation found that the number of inspectors that OSHA and the EPA have to oversee chemical facilities with catastrophic potential was limited compared to the large number of facilities (15,000). Michigan's OSHA state plan, MIOSHA, had only two PSM inspectors for the entire state, but had 2,800 facilities with catastrophic chemical risks. The NTSB reported that these inspections are necessarily complicated, resource-intensive, and rarely conducted by OSHA. NTSB concluded that OSHA did not provide effective oversight of such hazardous facilities.

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[236] www.osha.gov/pls/imis.

[237] These inspections included the code "PQV" in the inspection report.

11.1.2.7 OSHA PQV Inspection Resources

The OSHA PSM compliance directive includes training and experience requirements for inspectors who conduct PQV inspections. The directive states that “[A]ppropriate levels of staff training and preparation are essential for compliance activities relating to the PSM standard,” and that “[O]nly trained compliance safety and health officers (CSHOs) with experience in the chemical industry shall be assigned to lead a PQV inspection.” Specific training courses at the OSHA training institute are listed as minimum requirements for PQV inspectors.

An official from OSHA’s Houston South office stated that the only fully trained and experienced OSHA PSM inspection team in the United States is in that office and includes three to four inspectors. He added that a limited number of other inspectors nationwide have the necessary qualifications to conduct PQV inspections. The CSB submitted a number of requests for documents and interviews from OSHA regarding the PQV program, including numbers, training, education, and experience of PSM inspectors, but the requested information or interviews have not been provided.

11.1.3 Other Models for Process Safety Inspections

A review of the process safety programs in state plan OSHA states found that only six conducted PQV inspections (see next section). In addition, Contra Costa County (2007) in California has its own Industrial Safety Ordinance requiring inspections of covered facilities with catastrophic chemical hazards. The process safety inspection programs of the U.K. Health and Safety Executive were also examined in this investigation.

According to the CSB’s survey of state OSHA programs, Nevada and California each have process safety inspection programs. California inspects every refinery annually; Nevada inspects each PSM-covered facility annually, and conducts more comprehensive PQV-style inspections every five years.

Contra Costa County requires of the accident prevention programs at 48 covered facilities[238] an inspection every three years. Each year a staff of five engineers performs an average of 16 inspections.

The U. K's Control of Major Accident Hazards regulation (COMAH) requires facility operators to submit a safety report detailing their plan to prevent major accidents. Annually, 105 inspectors (typically engineers and scientists) visit high hazard facilities, and all COMAH-covered facilities are inspected every five years. For the nine refineries in the United Kingdom, detailed planned inspections (ranging from 80 to 150 days) are conducted annually for each refinery by a multidisciplinary team (regulatory inspectors, process safety, mechanical engineering, electrical and instrumentation, and human factors specialists).

Contra Costa County and the U.K. Health and Safety Executive conduct frequent scheduled inspections of PSM and major hazard facilities with highly qualified staff. Federal OSHA infrequently conducts planned PQV inspections. The CSB concludes that OSHA lacks sufficiently trained and experienced inspectors to effectively inspect PSM facilities.

11.1.3.1 PQV Inspections by Industry Segment and Region

The PSM Compliance Directive states that OSHA plans to focus more PQV inspections in OSHA Regions with higher concentrations of high hazard industries affected by the standard. While Region 6 (which includes Texas) contains more refineries (US Census Bureau, 2005) than any other region (51), OSHA conducted two planned PQV inspections in Region 6 (none in refining.) OSHA's inspection data was also analyzed to determine any correlation between the number of facilities within an industry sector and the number of inspections. Table 6 shows that the number of facilities in a sector (the eight industry sectors identified as targets in the PSM compliance directive) was not reflected in the number of PQV inspections.

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[238] Covered facilities are those classified as Tier 3 under EPA's Risk Management Plan Rule.

Table 6. PQV inspection[239] and facility numbers from 1995 to March 2005

Industry Sector	Number of Facilities [U.S. Census Bureau, 2005]	State PQV Inspections		Federal PQV Inspections		Federal PSM Local Emphasis Program Inspections	
		Planned	Unplanned	Planned	Unplanned	Planned	Unplanned
Alkalies and Chlorine (2812)	41	12	3	0	2	0	0
Industrial Inorganic Chemicals, Not Elsewhere Classified (2819)	631	18	7	1	14	0	0
Plastics Materials, Synthetic Resins, and Nonvulcanizable Elastomers (2821)	846	4	2	0	7	0	2
Cyclic Organic Crudes and Intermediates, and Organic Dyes and Pigments (2865)	179	0	0	0	4	1	4
Industrial organic chemicals, not elsewhere classified (2869)	685	3	1	4	19	2	1
Nitrogenous fertilizers (2873)	144	4	4	3	2	0	0
Explosives (2892)	87	1	1	1	8	0	1
Petroleum Refining (2911)	203[240]	6	11	0	21	1	0
Totals	**2816**	**48**	**29**	**9**	**77**	**4**	**8**

11.1.4 Summary and Discussion

OSHA's compliance directive for the PSM standard states that the main vehicle for enforcement is planned PQV inspections. However, PQV inspections are infrequent and an insufficient number of inspectors are qualified to conduct them.

[239] OSHA Integrated Management Information System (IMIS), inspections within industry, http://www.osha.gov/pls/imis/industry.html.

[240] The U.S. Energy Information Administration under its definition of an oil refinery states there are 144 refineries in the US.

Over time OSHA has adjusted enforcement priorities to reflect new workplace data and enforcement initiatives. For example, during the 1990s OSHA began collecting site specific injury data, which allowed improved targeting of planned inspections, and likely had the effect of putting greater emphasis on injury rates in overall inspection priorities. The incident at Texas City and its connection to serious process safety deficiencies at the refinery emphasize the need for OSHA to refocus resources on preventing catastrophic accidents through greater PSM enforcement.

The EPA estimates that 15,000 facilities are covered by RMP regulations similar in coverage to the PSM standard (Stephenson, 2004). OSHA's targeting of facilities for general safety and health inspections based on traditional safety measurements is ineffective in preventing catastrophic accidents. OSHA did not effectively inspect BP Texas City, despite its history of fatal accidents and releases. Additional factors for identifying facilities at risk for a catastrophic accident should include process safety performance indicators such as the resolution rate of PSM action items.

Strengthened enforcement of the PSM standard by OSHA through comprehensive, planned PQV inspections is needed to help prevent catastrophic accidents. Additional resources and inspector training are also needed. Finally, PQV inspection targeting must be based on effective metrics that help OSHA identify which facilities are at highest risk for a catastrophic incident. BP Texas City was a facility with very high risk for a catastrophe, but OSHA did not target the refinery for comprehensive planned inspections.

11.2 EPA's Risk Management Plan (RMP) Rule

The Clean Air Act of 1990 required that the EPA issue an accident prevention regulation to protect the public and the environment from catastrophic chemical releases from stationary sources, in addition to the

OSHA PSM Rule. The EPA's RMP[241] rule became effective in August 1996. In a separate regulation issued in 1997, the EPA published the list of chemicals covered by the RMP rule along with the threshold quantities (TQ) that determine if a process is covered.

The BP Texas City facility included many Program 3[242] processes covered by the RMP rule. The ISOM unit contained 1.5 million pounds of a mixture of flammables listed by the RMP rule (including pentane, propane, and butane), well above the 10,000-pound TQ for flammables.

11.2.1 Comparison to PSM

The RMP rule requires covered facilities to submit a risk management plan to the EPA. The rule provides less stringent requirements for smaller facilities or those with less likelihood of offsite injury or environmental damage from a release ("Program 1" and "Program 2" facilities). Refineries like BP Texas City ("Program 3" facilities) must fully comply with the rule's most stringent provisions. The accident prevention requirements for Program 3 facilities are similar to those of the OSHA PSM rule.

The RMP rule requires covered facilities to submit emergency contact information, descriptions of processes and hazardous chemicals onsite, accident history, and worst-case release scenarios. Facilities must update their risk management plan every five years or whenever a major accident occurs or the emergency contact information changes. BP submitted the first risk management plan when required in 1999, and has updated it at least three times.

[241] 40 CFR Chapter 1, Sub-chapter C, Part 68. http://www.access.gpo.gov/nara/cfr/cfrhtml_00/Title_40/40cfr68_00.html

[242] The EPA's RMP rule defines Program levels based upon process units' potential for impact to the public and the requirements to prevent accidents. Level 3 processes would affect the public in a worst case release and are subject to additional requirements to prevent accidents.

11.2.2 RMP Rule Enforcement

To date, the EPA enforcement of the RMP rule has focused primarily a review of the submitted RMPs and required updates by the covered facilities. In 1999, EPA established an audit program to help ensure compliance with the RMP. The audits were intended to provide an independent verification of the information in the RMP and include on-site inspections. EPA records show that the BP Texas City facility had not received a planned RMP rule audit prior to the ISOM incident. The CSB requested documents from the EPA about the RMP enforcement program and received a partial response: the EPA's response did not provide requested items such as the total number of RMP audits conducted, the audit selection process description, audit reports, and the number of RMP inspectors.

12.0 ROOT AND CONTRIBUTING CAUSES

12.1 Root Causes

BP Group Board did not provide effective oversight of the company's safety culture and major accident prevention programs.

Senior executives:

- inadequately addressed controlling major hazard risk. Personal safety was measured, rewarded, and the primary focus, but the same emphasis was not put on improving process safety performance;
- did not provide effective safety culture leadership and oversight to prevent catastrophic accidents;
- ineffectively ensured that the safety implications of major organizational, personnel, and policy changes were evaluated;
- did not provide adequate resources to prevent major accidents; budget cuts impaired process safety performance at the Texas City refinery.

BP Texas City Managers did not:

- create an effective reporting and learning culture; reporting bad news was not encouraged. Incidents were often ineffectively investigated and appropriate corrective actions not taken.
- ensure that supervisors and management modeled and enforced use of up-to-date plant policies and procedures.

- incorporate good practice design in the operation of the ISOM unit. Examples of these failures include:
  - no flare to safely combust flammables entering the blowdown system;
  - lack of automated controls in the splitter tower triggered by high-level, which would have prevented the unsafe level; and
  - inadequate instrumentation to warn of overfilling in the splitter tower.
- ensure that operators were supervised and supported by experienced, technically trained personnel during unit startup, an especially hazardous phase of operation; or that
- effectively incorporated human factor considerations in its training, staffing, and work schedule for operations personnel.

12.2 Contributing Causes

BP Texas City managers:

- lacked an effective mechanical integrity program to maintain instruments and process equipment. For example, malfunctioning instruments and equipment were not repaired prior to startup.
- did not have an effective vehicle traffic policy to control vehicle traffic into hazardous process areas or to establish safe distances from process unit boundaries.
- ineffectively implemented their PSSR policy; nonessential personnel were not removed from areas in and around process units during the hazardous unit startup.
- lacked a policy for siting trailers that was sufficiently protective of trailer occupants.

13.0 RECOMMENDATIONS[243]

American Petroleum Institute (API) and United Steelworkers International Union (USW)

Work together to develop two new consensus American National Standards Institute (ANSI) standards.

2005-4-I-TX-R6 In the first standard, create performance indicators for process safety in the refinery and petrochemical industries. Ensure that the standard identifies leading and lagging indicators for nationwide public reporting as well as indicators for use at individual facilities. Include methods for the development and use of the performance indicators.

2005-4-I-TX-R7 In the second standard, develop fatigue prevention guidelines for the refining and petrochemical industries that, at a minimum, limit hours and days of work and address shift work.

In the development of each standard, ensure that the committees

a. are accredited and conform to ANSI principles of openness, balance, due process, and consensus;

b. include representation of diverse sectors such as industry, labor, government, public interest and environmental organizations and experts from relevant scientific organizations and disciplines.

[243] See Appendix C for previously issued recommendations.

Occupational Safety and Health Administration (OSHA)

2005-4-I-TX-R8 Strengthen the planned comprehensive enforcement of the OSHA Process Safety Management (PSM) standard. At a minimum:

a. Identify those facilities at greatest risk of a catastrophic accident by using available indicators of process safety performance and information gathered by the EPA under its Risk Management Program (RMP).

b. Conduct, or cause to be conducted, comprehensive inspections, such as those under your Program Quality Verification (PQV) program at facilities identified as presenting the greatest risk.

c. Establish the capacity to conduct more comprehensive PSM inspections by hiring or developing a sufficient cadre of highly trained and experienced inspectors.

d. Expand the PSM training offered to inspectors at the OSHA National Training Institute.

2005-4-I-TX-R9 Amend the OSHA PSM standard to require that a management of change (MOC) review be conducted for organizational changes that may impact process safety including

a. major organizational changes such as mergers, acquisitions, or reorganizations;

b. personnel changes, including changes in staffing levels or staff experience; and

c. policy changes such as budget cutting.

Center for Chemical Process Safety (CCPS)

2005-4-I-TX-R10 Issue management of change guidelines that address the safe control of the following:

a. major organizational changes including mergers, acquisitions, and reorganizations

b. changes in policies and budgets

c. personnel changes

d. staffing during process startups, shutdowns and other abnormal conditions.

BP Board of Directors

2005-4-I-TX-R11 Appoint an additional non-executive member of the Board of Directors with specific professional expertise and experience in refinery operations and process safety. Appoint this person to be a member of the Board Ethics and Environmental Assurance Committee.

2005-4-I-TX-R12 Ensure and monitor that senior executives implement an incident reporting program throughout your refinery organization that

a. encourages the reporting of incidents without fear of retaliation;

b. requires prompt corrective actions based on incident reports and recommendations, and tracks closure of action items at the refinery where the incident occurred and other affected facilities; and

c. requires communication of key lessons learned to management and hourly employees as well as to the industry.

2005-4-I-TX-R13 Ensure and monitor that senior executives use leading and lagging process safety indicators to measure and strengthen safety performance in your refineries.

BP Texas City Refinery

2005-4-I-TX-R14 Evaluate your refinery process units to ensure that critical process equipment is safely designed. At a minimum,

a. Ensure that distillation towers have effective instrumentation and control systems to prevent overfilling such as multiple level indicators and appropriate automatic controls.

b. Configure control board displays to clearly indicate material balance for distillation towers.

2005-4-I-TX-R15 Ensure that instrumentation and process equipment necessary for safe operation is properly maintained and tested. At a minimum,

a. Establish an equipment database that captures the history of testing, inspections, repair, and successful work order completion.

b. Analyze repair trends and adjust maintenance and testing intervals to prevent breakdowns.

c. Require repair of malfunctioning process equipment prior to unit startups.

2005-4-I-TX-R16 Work with the United Steelworkers Union and Local 13-1 to establish a joint program that promotes the reporting, investigation, and analysis of incidents, near-misses, process upsets, and major plant hazards without fear of retaliation. Ensure that the program tracks recommendations to completion and shares lessons learned with the workforce.

2005-4-I-TX-R17 Improve the operator training program. At a minimum, require

a. face-to-face training conducted by personnel with process-specific knowledge and experience who can assess trainee competency, and

b. training on recognizing and handling abnormal situations including the use of simulators or similar training tools.

2005-4-I-TX-R18 Require additional board operator staffing during the startup of process units. Ensure that hazard reviews address staffing levels during abnormal conditions such as startups, shutdowns, and unit upsets.

2005-4-I-TX-R19 Require knowledgeable supervisors or technically trained personnel to be present during especially hazardous operation phases such as unit startup.

2005-4-I-TX-R20 Ensure that process startup procedures are updated to reflect actual process conditions.

United Steelworkers International Union and Local 13-1

2005-4-I-TX-R21 Work with BP to establish a joint program that promotes reporting, investigating, and analyzing incidents, near-misses, process upsets, and major plant hazards without fear of retaliation. Ensure that the program tracks recommendations to completion and shares lessons learned with the workforce.

By the

U.S. Chemical Safety and Hazard Investigation Board

Carolyn W. Merritt
Chair

John S. Bresland
Member

Gary L. Visscher
Member

William B. Wark
Member

William E. Wright
Member

Date of Board Approval

Appendix A: Texas City Timeline 1950s – March 23, 2005

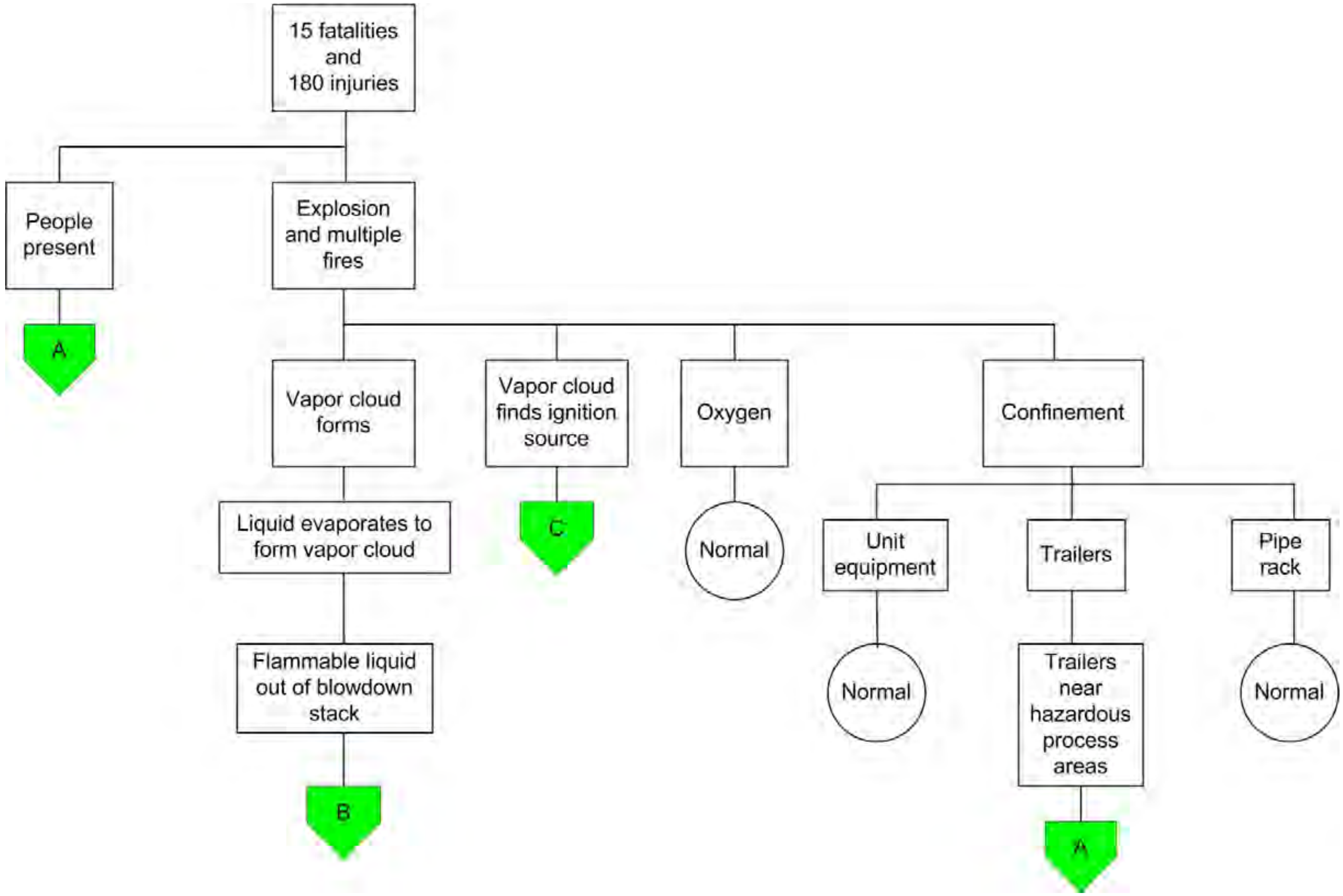
Date	Event
1950s	The ISOM blowdown system is installed in the southwest corner of the ISOM unit
1957	The blowdown system is moved approximately 200 ft to the northwest corner of the ISOM unit battery limits
1976	The HUF fractionator is installed into what is now the ISOM unit
1985	The HUF fractionator is converted into the raffinate splitter tower
1986	The raffinate splitter tower's capacity is increased
1987	The capacity of the splitter tower is increased again
1991	The Amoco Refining Planning Department (ARPD) proposes a strategy to eliminate blowdown stacks that vent to the atmosphere
1992	ARPD does not include separate funding for flare/blowdown work in the 10-year capital plan because state and federal regulations are unlikely to require that relief valves be routed to closed systems in the foreseeable future
1992	OSHA cites a similar blowdown drum and stack as unsafe at the Texas City refinery and recommends it be reconfigured to a closed system with a flare
1993	The Amoco Regulatory Cluster Project plans to eliminate all blowdown stacks and replace them with knockout drums; however, due to the project cost of $400 million, the project is not implemented
1993	A PHA HAZOP is conducted on the ISOM unit; consequences of high level and high pressure in the splitter tower are not addressed, and the sizing of the blowdown drum for containment of liquid release is not considered
1994	An Amoco staffing review concludes that the company will reap substantial cost savings if staffing is reduced at the Texas City and Whiting sites to match Solomon performance indices
12-Feb-94	The 115-ft DIH distillation tower in the ISOM unit is overfilled and results in a hydrocarbon vapor cloud release out of the relief valves that open to the blowdown drum and stack
17-Feb-94	Leaking DIH relief valves result in a vapor release out of the ISOM blowdown stack; part of the unit is shut down
27-Feb-94	The ISOM stabilizer tower emergency relief valves open five or six times over four hours, releasing a large vapor cloud near ground level; it is misreported in the event log as a much smaller incident and no safety investigation is conducted
Mar-94	A BP engineer reviews a contractor study of the headers that discharge into the blowdown drum and concludes that all relief headers are properly sized; unfortunately, the raffinate splitter tower header is not included in the contractor study
Mar-94	OSHA and Amoco agree to a settlement regarding the 1992 citation; the blowdown drum, like the ISOM blowdown drum, remains open to atmosphere
24-Jul-94	The Texaco Milford Haven refinery in the U.K. experiences a plant upset when a distillation tower is overfilled and releases hydrocarbons into the atmosphere
1995	At an IChemE conference, BP presents its findings from a study conducted at its Grangemouth refinery that examined shift turnover communication and resulted in several improvements in how its operations personnel communicated at the refinery
8-May-95	The 8-inch chain vent valve of the raffinate splitter tower overhead piping is inadvertently left open for over 20 hours during a raffinate section startup, resulting in a significant vapor cloud release out of the blowdown stack
1996	A staffing assessment of the Texas City refinery process units reveals that personnel are concerned that staffing is too minimal to handle unit upsets
1997	The approximately 40-year-old ISOM blowdown drum and stack are completely replaced with similar but not identically-sized equipment, yet a flare is not connected to it
1997	BP Group's Getting Health, Safety and the Environment Right (GHSER) policy is established
1997	Behavioral safety programs begin to go into effect at the Texas City site
1998	BP's Learning & Development department has a budget of $2.8 million and a central staff of 28 trainers
1998	The ISOM unit's HAZOP revalidation does not address previous incidents with catastrophic potential, as required by the PSM standard

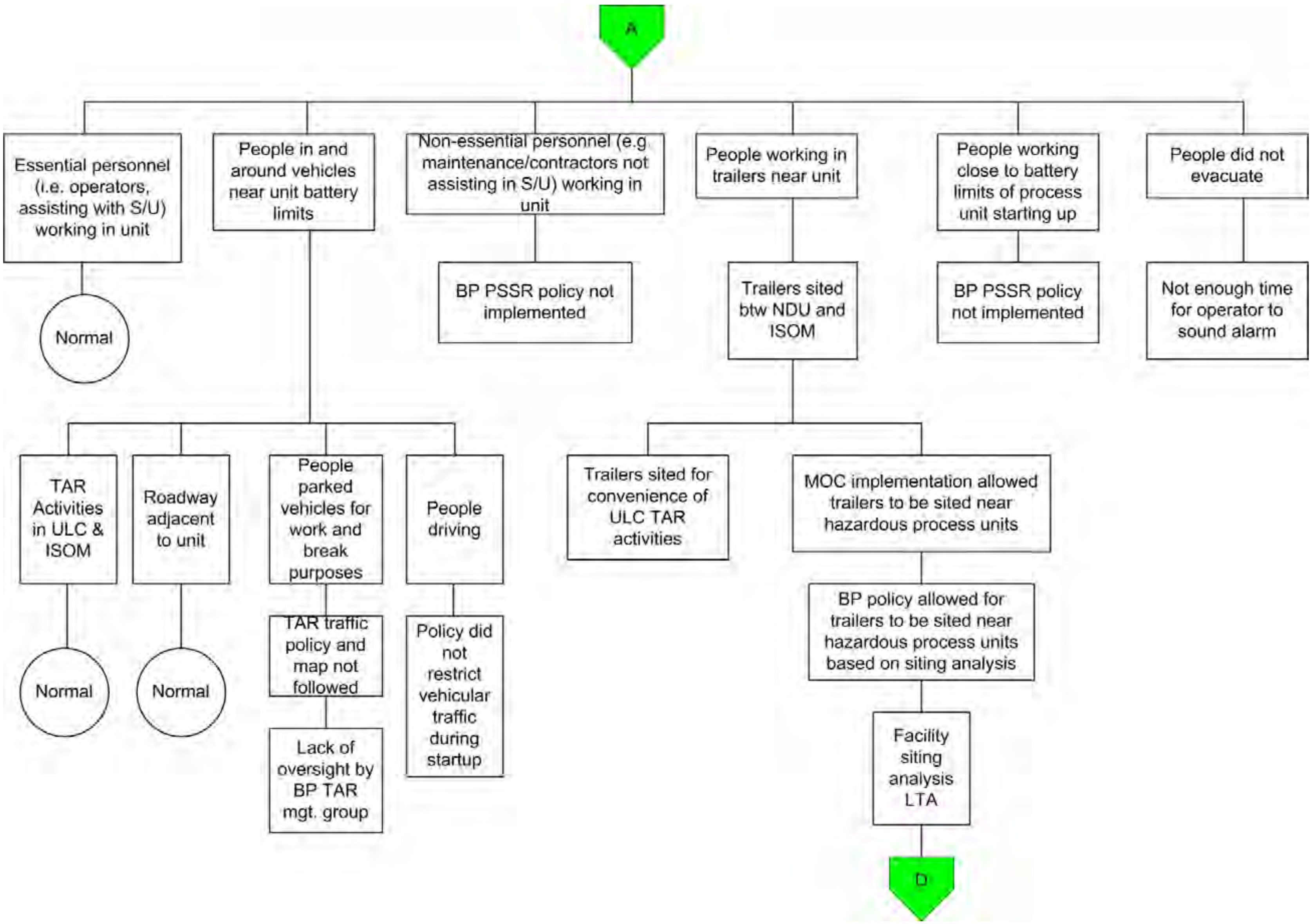
Date	Event
4-Oct-98	The ISOM blowdown stack catches fire during stormy weather, resulting in a unit upset; management does not investigate
31-Dec-98	BP merges with Amoco
1999	Texas City refinery is a separate business unit run by a director
1999	BP Group Management directs Texas City to cut costs 25%
16-Jan-99	During an ISOM unit shutdown, hydrocarbon liquid flows from the blowdown into the sewer system and hydrocarbons vapors release out of the sewer boxes, producing a significant vapor cloud
16-Feb-00	The Day Board Operator receives refresher training on the ISOM unit via a computerized training course
2000	A series of incidents occur at BP's Grangemouth refinery in Scotland
23-Jul-00	The ISOM blowdown stack catches fire, fueled by leaking pressure relief valves on the hydrogen driers; the fire continues over five 12-hour shifts before it is extinguished; no investigation is conducted
Oct-00	BP's in-house magazine publishes a document written by the Group Chief Executive who asserts that BP will learn the lessons from Grangemouth and other incidents
2000	BP's Learning & Development department presses Texas City management for simulators to aid in training unit operators, but are unsuccessful in obtaining such technologies
2001	The Texas City refinery joins four other facilities to become part of the BP South Houston complex, run by one site director who oversees each facility's Business Unit Leader
2001	The presentation, "Texas City Refinery Safety Challenge," is given to BP management; it predicts an employee death in the next 3-4 years
2001	The PSM audit finds a substantial number of PHA action items still open well past their stated due dates, and a number of unit operating procedures that are not current
May-01	BP Group issues a "Process Safety/Integrity Management" standard, which outlines the minimum requirements to prevent catastrophic incidents
2002	BP engineers propose connecting the ISOM blowdown system to a flare, but a less expensive option is chosen
2002	The Texas City Refinery Retrospective Analysis determines that capital spending has been reduced 84% from 1992 to 2000, and that many budget cuts do not consider the specific maintenance needs of the refinery
2002	A BP Group report on the Group Fatal Accident Investigation process finds that root causes are not being identified and corrective actions are not always practical or clear
summer 2002	The refinery HSE department initiates the Clean Streams project with the goal of identifying and eliminating liquid streams routed to blowdown stacks; the ISOM unit is scheduled to be one of the first to undergo such changes
Aug-02	The "Veba" study concludes that Texas City has serious deficiencies with mechanical integrity, inspections, and instrumentation, as well as a high likelihood for a major incident
Apr-03	As the Clean Streams project budget increases from \$6 to \$89 million, its scope is altered and work plans for the ISOM unit are cancelled
2003	The "Getting Maintenance and Reliability Right Gap Assessment" reveals that maintenance and mechanical integrity problems persist at the Texas City refinery
2003	An internal inspection of the blowdown drum reveals that most vessel shed trays have collapsed in the bottom of the drum. The remaining trays that are still attached are considered dangerous to personnel, so the internal inspection is terminated and the drum is closed without recommending that the drum be taken out of service or repaired
2003	The second ISOM unit HAZOP revalidation again does not address previous incidents with catastrophic potential
2003	A process safety analysis action item requires a review of the ISOM unit's relief valves; the target completion date is March 31, 2005, seven days after the explosion; the study is never completed
2003	A major modification of the blowdown drum occurred in 2003 when the quench capabilities of the drum fail due to corrosion and remained in disrepair until the time of the incident

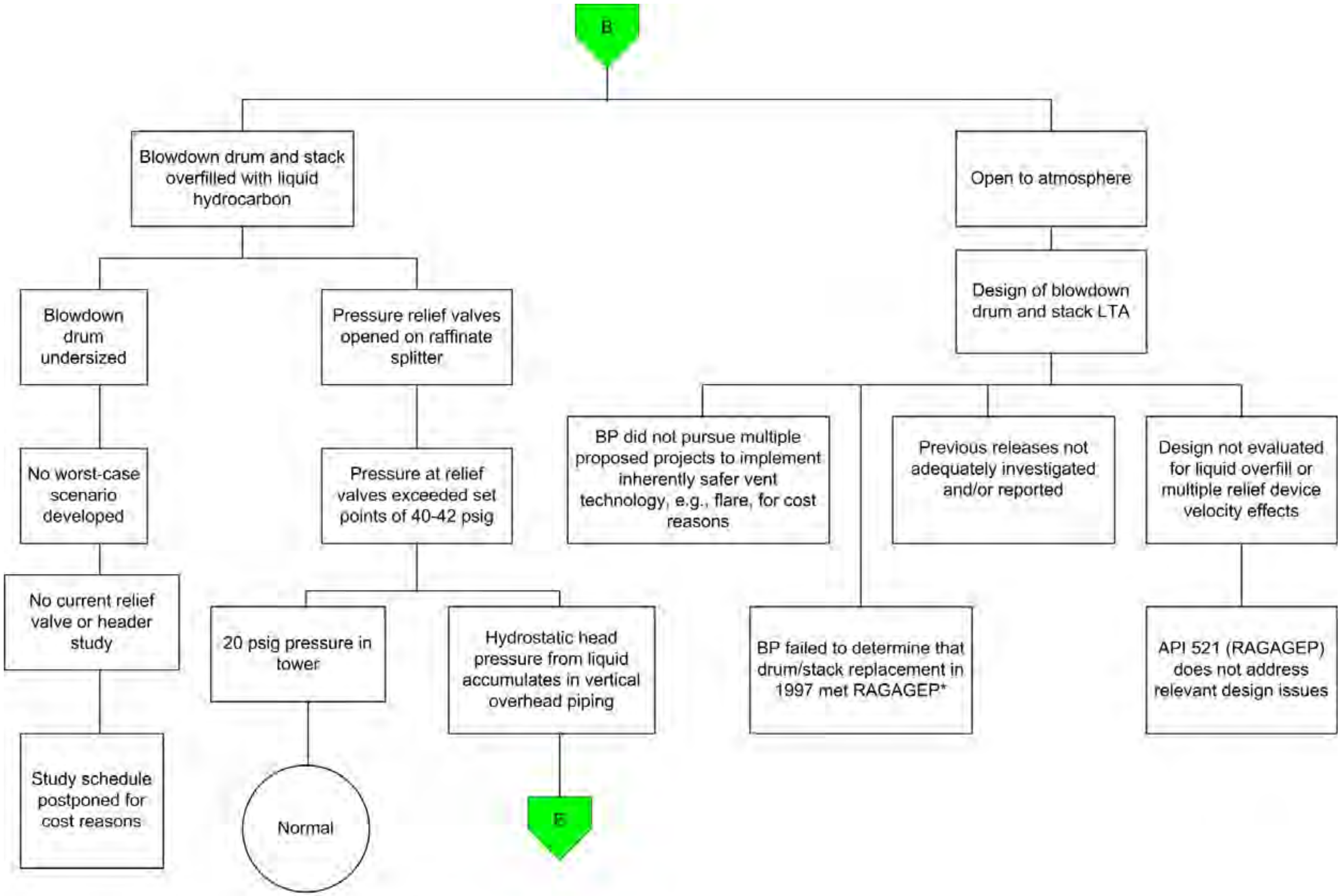
Date	Event
Aug-03	The Texas City Refinery Repositioning Project is initiated at the request of BP Group Refining management because the refinery has not made a profit contribution proportionate to its capital consumption
Sep-03	The 2003 GHSER audit determines that the Texas City refinery infrastructure and assets are in poor condition, and that both training and incident investigation activities are insufficient
2003	The South Houston Infrastructure for Tomorrow (SHIFT) program is implemented
2003	The 1,000 Day Goals program is developed to measure site-specific performance; it focuses on personal safety and cost-cutting, rather than on process safety
2003	The refinery-wide Operator Competency Assurance Model audit finds that no individual operator development plans are being developed for AU2/ISOM/NDU unit operators
2004	BP's Learning & Development department has a budget of $1.4 million and a central staff of 8 trainers
2004	The Texas City business unit leader/plant manager gives a presentation entitled "Safety Reality" to 100 supervisory personnel regarding the 23 deaths in the plant in the previous 30 years
2004	A new behavior initiative is put in place, resulting in behavior safety training for nearly all BP Texas City employees
2004	The PSM audit notes that many relief valves are missing engineering documentation, safeguards are not clearly defined, no official process for communicating lessons learned from previous incidents is in place, and unit managers and operators lack training
Mar-04	After an inspection of the raffinate unit reveals significant corrosion under the insulation on the exterior of the splitter, its relief pressure is lowered to 40 psig (276 kPa) and the safety relief valves are lowered to 40, 41, and 42 psig; (276, 283, and 290 kPa) however, the startup procedures do not incorporate this pressure change
Mar-04	A furnace outlet pipe ruptures in the UU4 unit, resulting in a fire that causes $30 million in damages
Mar-04	The BP Internal Audit Group in London releases its report on GHSER audit findings of all its business units; non-compliance of HSE rules, poor implementation of HSE management systems, lack of learning from previous incidents, and lack of leadership and monitoring are common deficiencies among the different sites
Mar-04	The DIH tower pressure relief valves again lift after a short loss of electric power to the ISOM unit, resulting in a significant vapor cloud at or near ground level
Apr-04	BP South Houston is dissolved and the Texas City refinery is once again a separate business unit run by a business unit leader who reports directly to the Regional Group VP of Refining
Apr-04	The Day Board Operator is certified that he has the necessary knowledge to conduct unit startup when a process technician (PT) tests him verbally on the process
Jun-04	The GHSER assessment grades Texas City as "poor" because accident investigations are not thoroughly analyzed for trends and preventative programs are not being developed
May-04	The Texas City site “Control of Work Review” reveals deficiencies in compliance with the Golden Rules of Safety (personal safety issues)
Spring 2004	In response to the findings of the “Control of Work Review,” Texas City implements the “Compliance Delivery Process” and “Just Culture” programs that enforce adherence of site rules, promote individual accountability, and punish rule violations
Jul-04	The BP Group Chief Executive for Refining and Marketing visits Texas City to review progress toward the 1,000 Day Goals; the site reports a "best ever" recordable injury frequency rate, but that the refinery needs to reduce its maintenance spending to improve profitability
Aug-04	The Texas City Process Safety Manager gives a presentation to plant managers that identifies serious problems with process safety performance
Aug-04	Pressure relief valves open in the Ultracracker unit, discharging liquid hydrocarbons to the ULC blowdown drum and out of the stack
Sep-04	Two employees are killed and another seriously injured when burned with hot water and steam during the opening of a pipe flange in the UU3 unit
Sep-04	The Texas City Process Safety Manager tells the site director that Texas City received poor scores on PSM-related metrics, such as action item completion, and that incident investigations are not identifying the underlying root causes

Date	Event
Sep-04	BP sites the double-wide trailer between the NDU and ISOM units to house contractor employees for turnaround work in the nearby Ultracracker unit
Oct-04	The Texas City site leader meets with the R&M Chief Executive and Senior Executive Team to discuss the 2004 incidents; management discusses how these incidents are the result of casual compliance and personal risk tolerance despite two of the three incidents being directly process-safety related
2004	The 2004 PSM audit reveals poor PSM performance of the Texas City refinery, especially in mechanical integrity, training, process safety information, and management of change (MOC)
Nov-04	Plant leadership meets with all site supervisors for a "Safety Reality" presentation that declares that Texas City is not a safe place to work
late 2004	BP Group refining leadership gives the Texas City refinery business unit leader a 25% budget cut "challenge" for 2005; the business unit leader asks for more funds due to the conditions of the refinery, but less than half of the 25% cuts are restored
late 2004	The Telos survey is conducted to assess safety culture at the refinery and finds serious safety issues
2004	The refinery-wide OCAM audit finds that only 25% of ISOM unit operators are given performance appraisals annually, and that no individual operator development plans are being developed for unit operators; the audit also finds that the budget allows for no training beyond initial new employee and OSHA-required refresher information
Jan-Feb-05	Nine additional trailers are placed in the area between the NDU and ISOM units
Jan-05	The Telos Report is issued with recommendations to improve the significantly deficient organizational and cultural conditions of the Texas City refinery
Feb-05	The BP Group VP and the North American VP for Refining meet with refinery managers in Houston, where they are presented with information on the Telos report findings, the deteriorating conditions of the refinery, budget cuts, inadequate training, pressures of production overshadowing safety, and the 2004 fatality incidents
2005	The 2005 Texas City HSSE Business Plan warns management that that refinery will likely "kill someone in the next 12-18 months."
Mar-05	The Texas City Process Safety Manager tells management that PSM action item closure is still a significant concern and this metric is finally added to the site's 1,000 Day Goals
23-Mar-05	Explosion and fire at the Texas City refinery results in 15 fatalities and 180+ injuries
Apr-05	Due to 23 deaths at the Texas City refinery in 30 years, OSHA puts BP onto its list of "Enhanced Enforcement Program for Employers Who are Indifferent to Their Obligations"
Jul-05	An incident in the RHU results in a shelter-in-place of the community and $30 million in damage at the refinery
Aug-05	A release in the CFHU results in a shelter-in-place and $2 million in damage at the refinery
Sep-05	OSHA fines BP $21 million for 301 egregious willful violations
13-Dec-05	During unit startup, a distillation tower at the BP Whiting refinery in Indiana is overfilled, resulting in fire and damage.

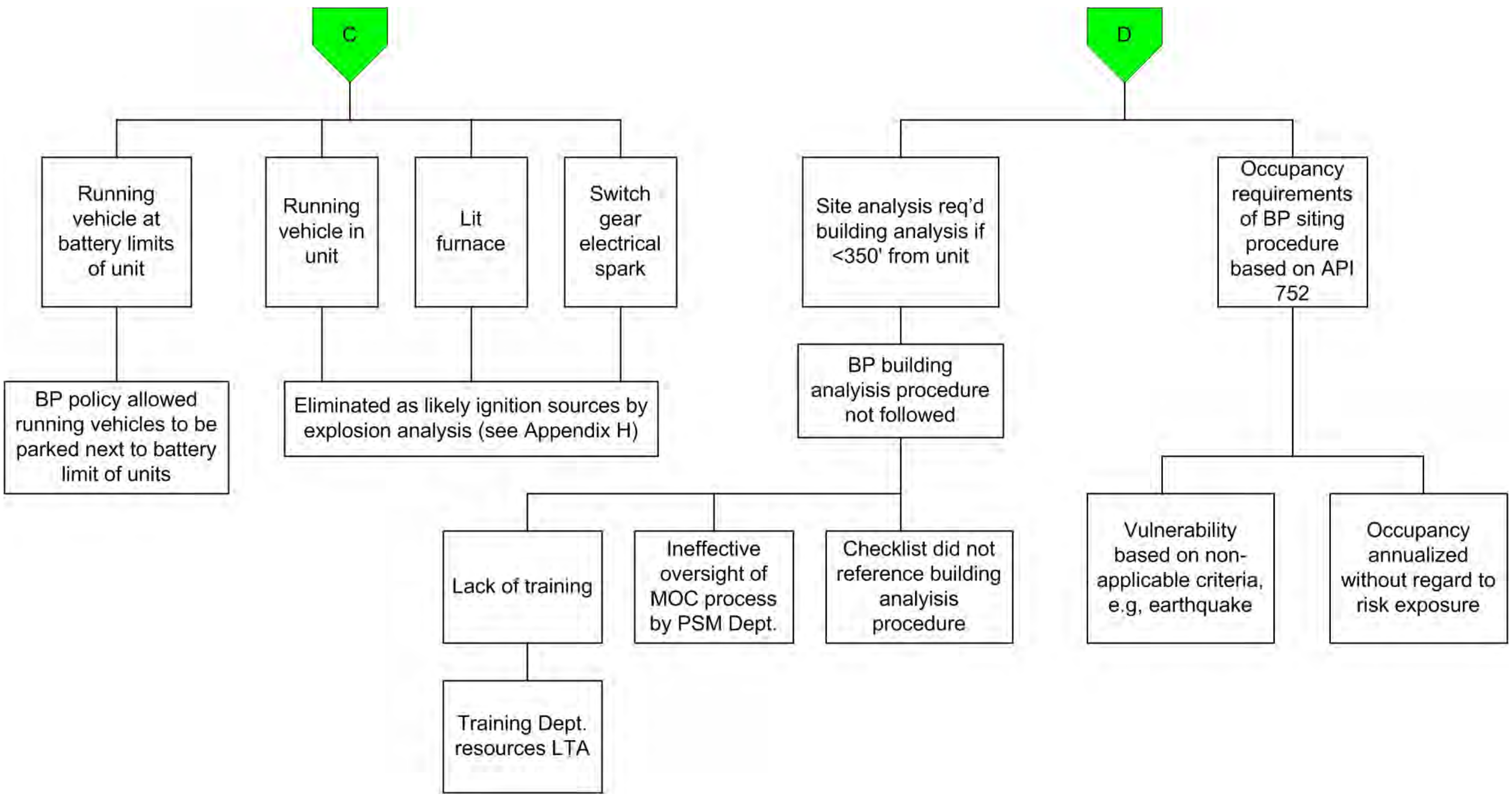
Appendix B: Logic Tree

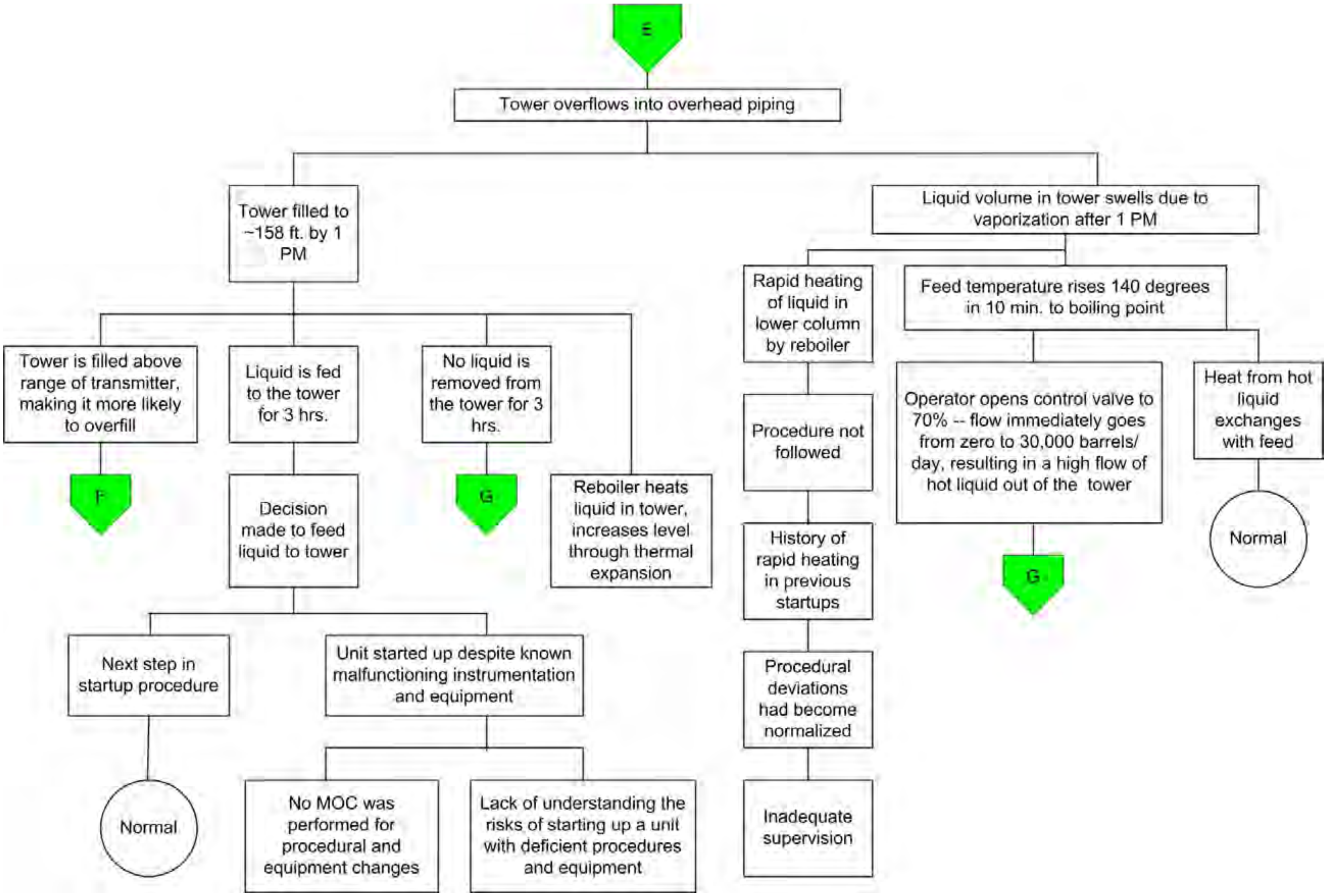


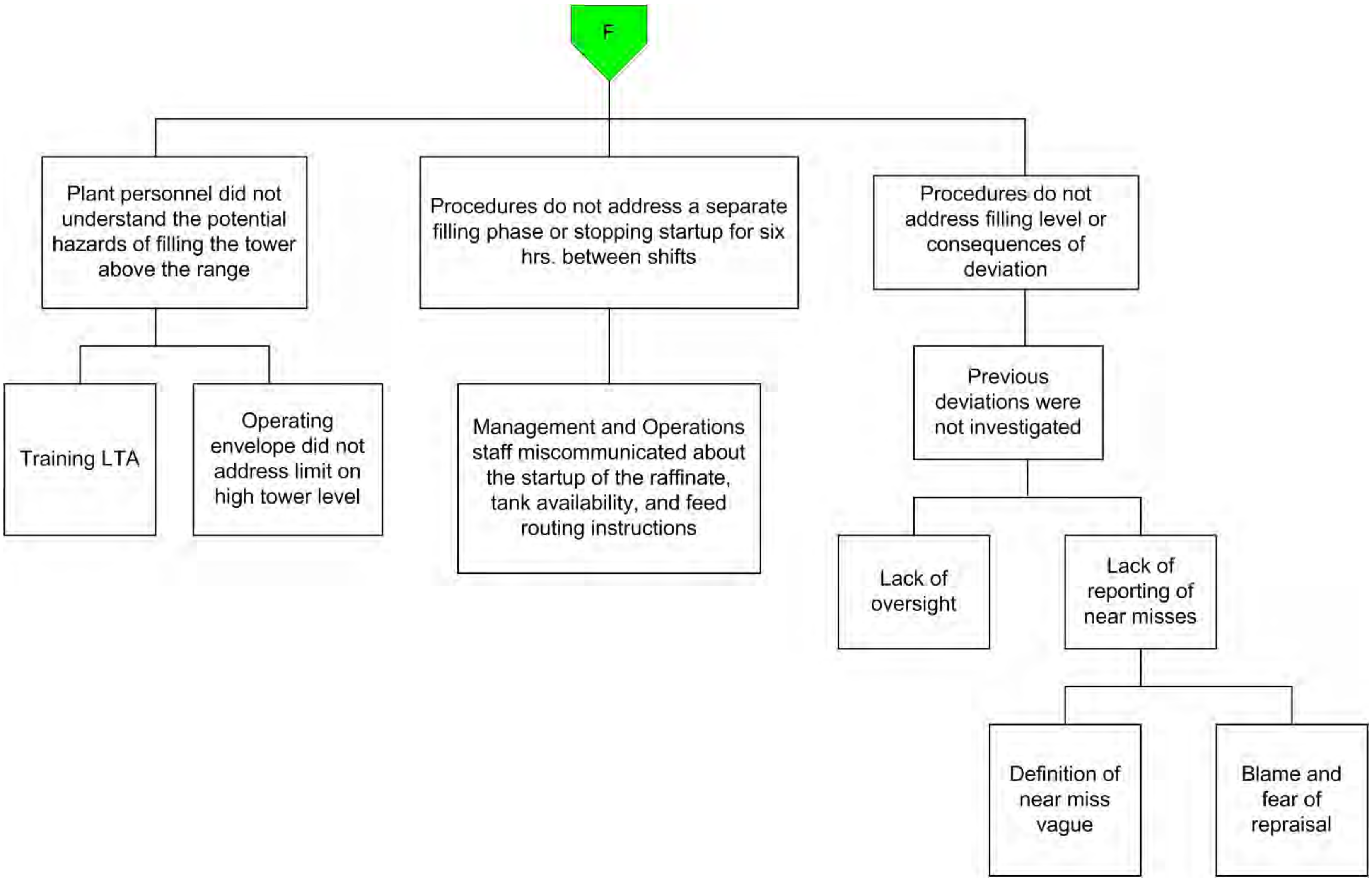

A
Essential personnel (i.e. operators, assisting with S/U) working in unit
People in and around vehicles near unit battery limits
Non-essential personnel (e.g maintenance/contractors not assisting in S/U) working in unit
People working in trailers near unit
People working close to battery limits of process unit starting up
People did not evacuate
Normal
BP PSSR policy not implemented
Trailers sited btw NDU and ISOM
BP PSSR policy not implemented
Not enough time for operator to sound alarm
TAR Activities in ULC & ISOM
Roadway adjacent to unit
People parked vehicles for work and break purposes
People driving
Trailers sited for convenience of ULC TAR activities
MOC implementation allowed trailers to be sited near hazardous process units
Normal
Normal
TAR traffic policy and map not followed
Policy did not restrict vehicular traffic during startup
BP policy allowed for trailers to be sited near hazardous process units based on siting analysis
Lack of oversight by BP TAR mgt. group
Facility siting analysis LTA
D

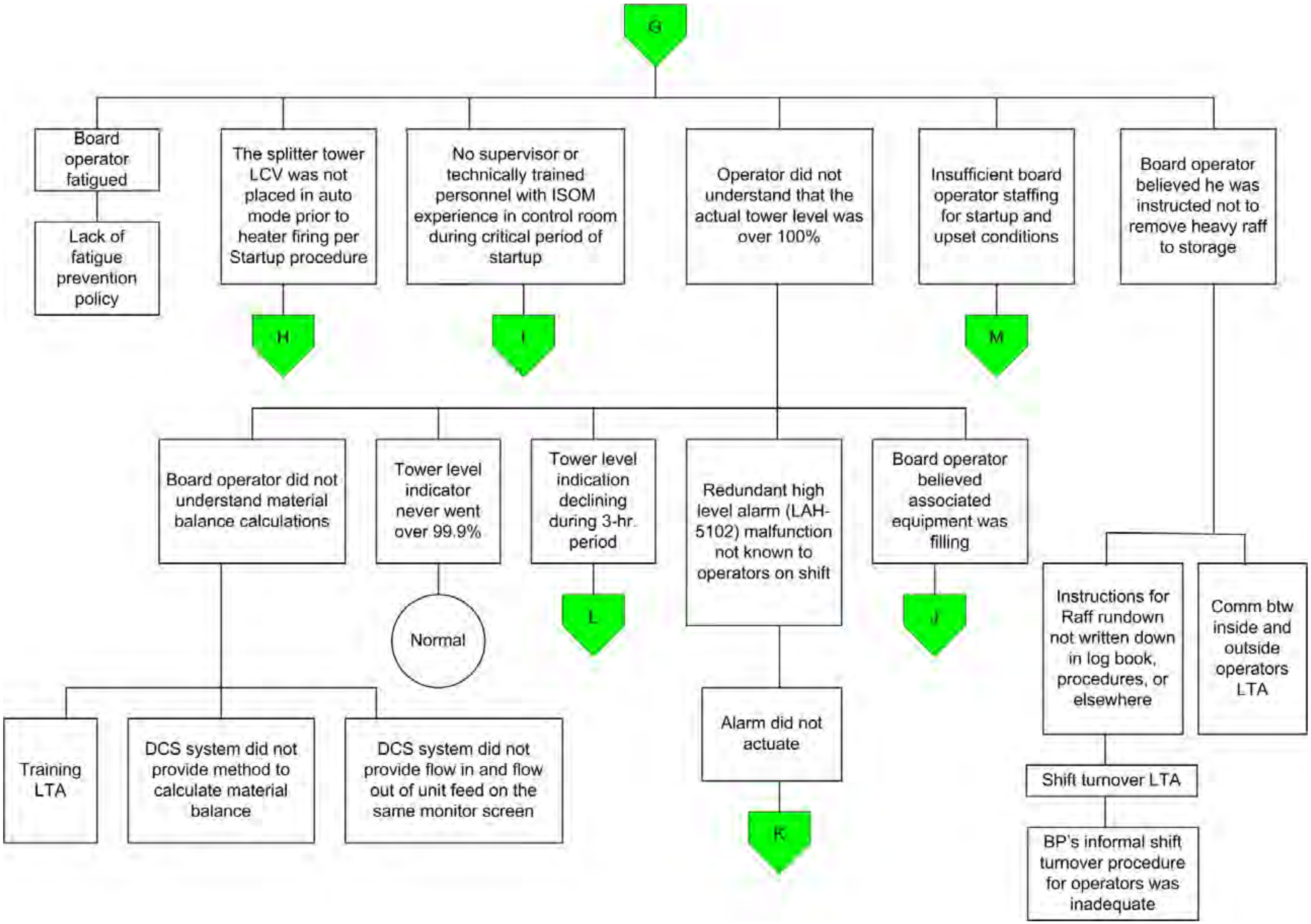


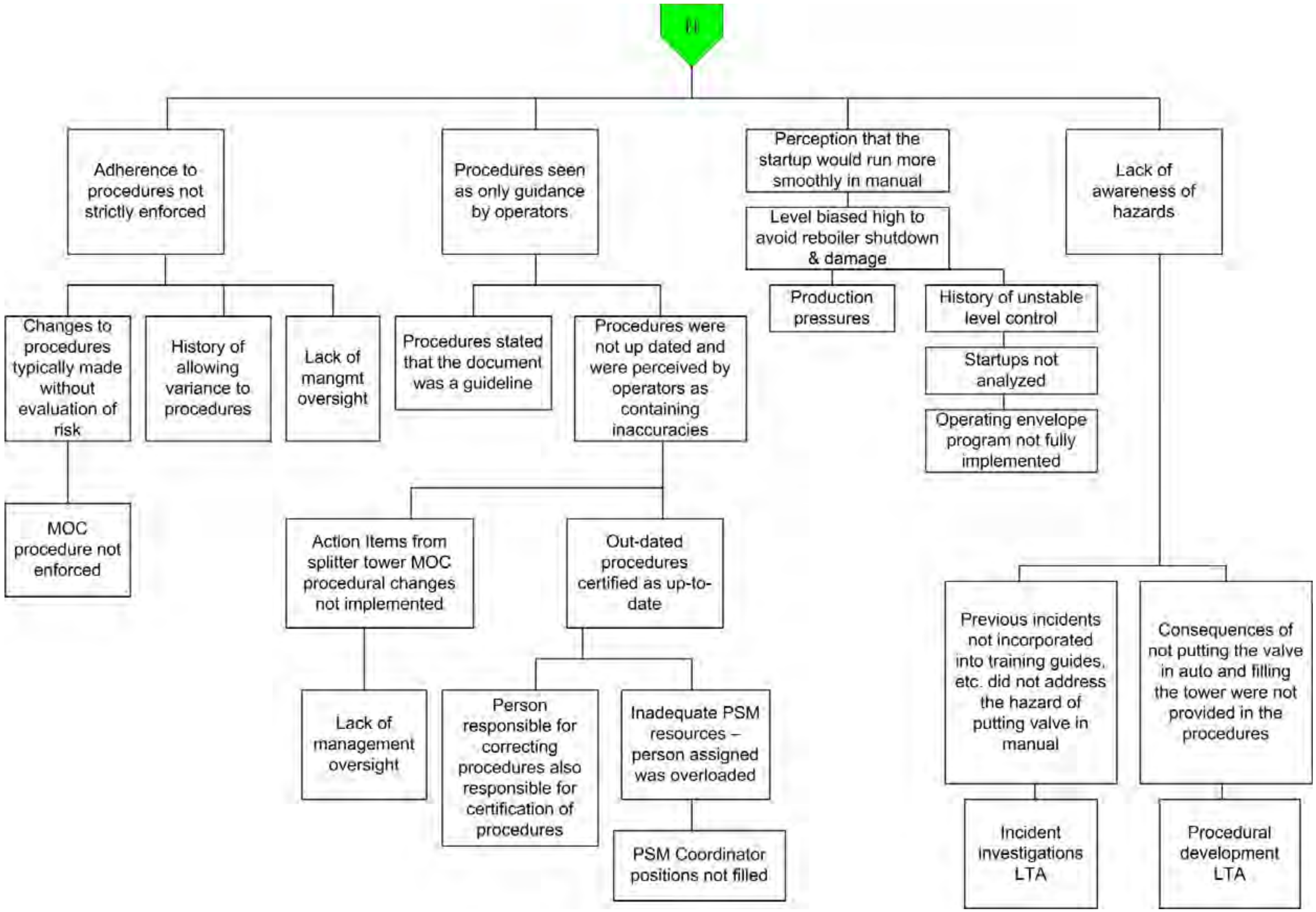
*RAGAGEP = Recognized and generally accepted good engineering practice

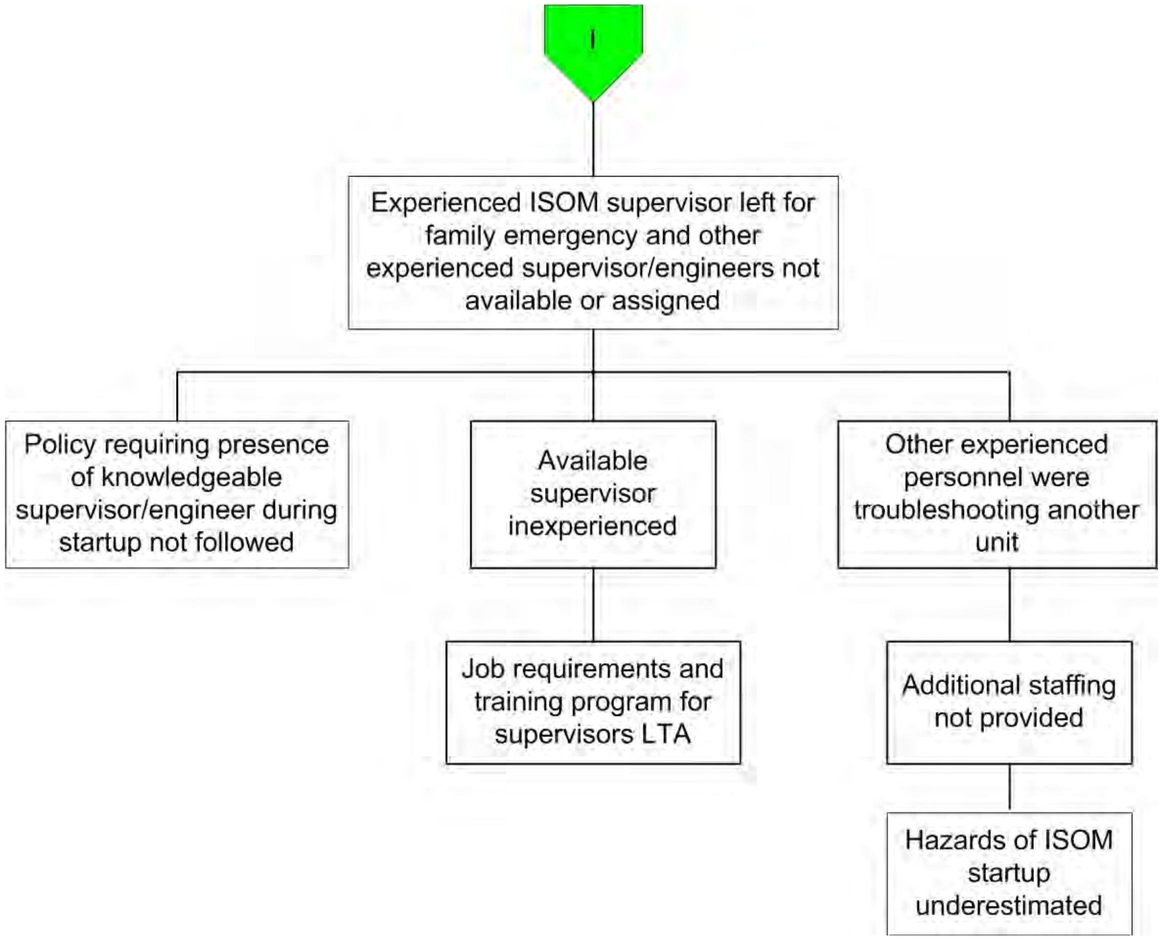

C
Running vehicle at battery limits of unit
Running vehicle in unit
Lit furnace
Switch gear electrical spark
BP policy allowed running vehicles to be parked next to battery limit of units
Eliminated as likely ignition sources by explosion analysis (see Appendix H)
D
Site analysis req'd building analysis if <350' from unit
Occupancy requirements of BP siting procedure based on API 752
BP building analyisis procedure not followed
Lack of training
Ineffective oversight of MOC process by PSM Dept.
Checklist did not reference building analyisis procedure
Training Dept. resources LTA
Vulnerability based on non-applicable criteria, e.g, earthquake
Occupancy annualized without regard to risk exposure

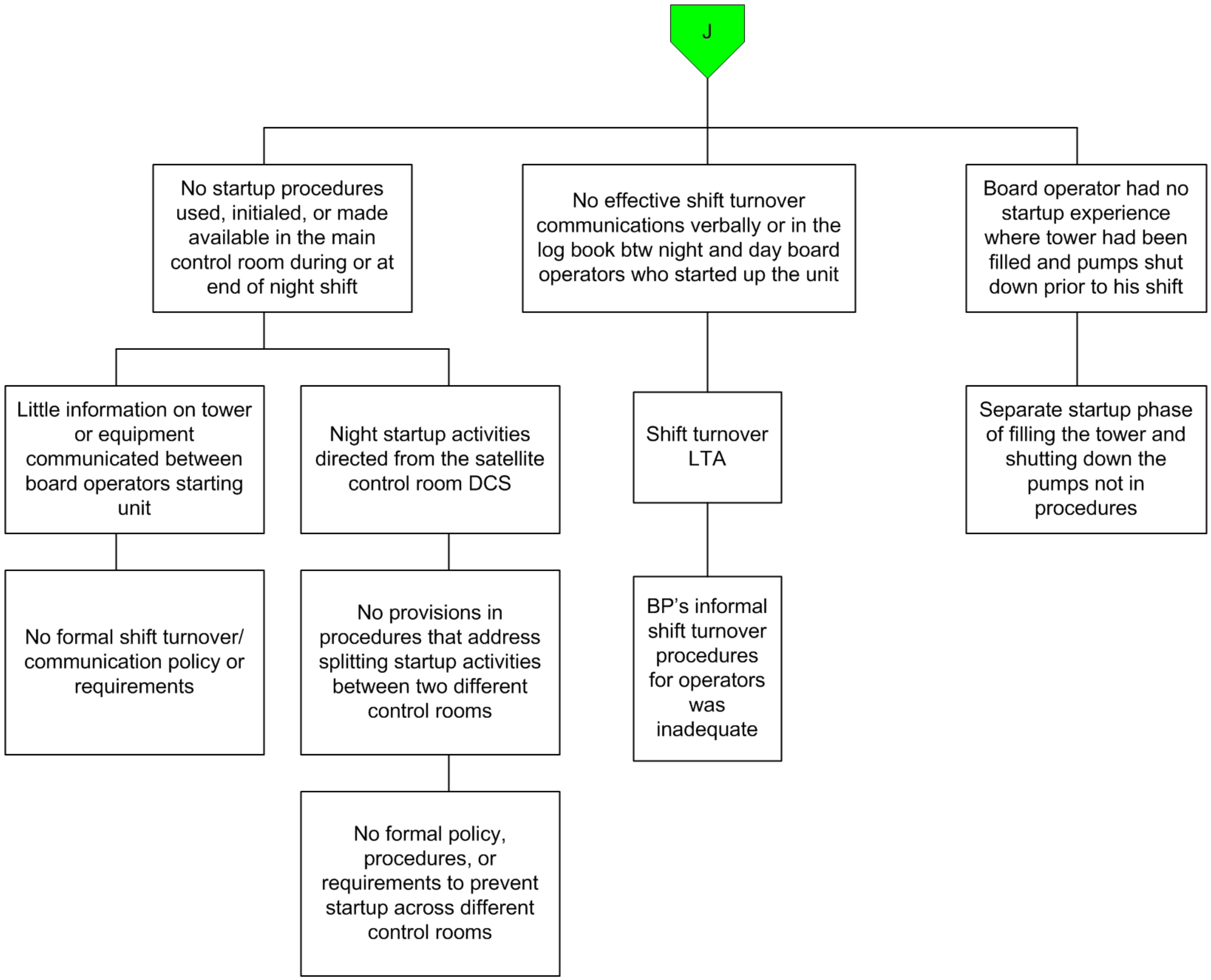

E
Tower overflows into overhead piping
Tower filled to ~158 ft. by 1 PM
Liquid volume in tower swells due to vaporization after 1 PM
Tower is filled above range of transmitter, making it more likely to overfill
Liquid is fed to the tower for 3 hrs.
No liquid is removed from the tower for 3 hrs.
Reboiler heats liquid in tower, increases level through thermal expansion
F
G
Decision made to feed liquid to tower
Next step in startup procedure
Normal
Unit started up despite known malfunctioning instrumentation and equipment
No MOC was performed for procedural and equipment changes
Lack of understanding the risks of starting up a unit with deficient procedures and equipment
Rapid heating of liquid in lower column by reboiler
Procedure not followed
History of rapid heating in previous startups
Procedural deviations had become normalized
Inadequate supervision
Feed temperature rises 140 degrees in 10 min. to boiling point
Operator opens control valve to 70% -- flow immediately goes from zero to 30,000 barrels/ day, resulting in a high flow of hot liquid out of the tower
G
Heat from hot liquid exchanges with feed
Normal

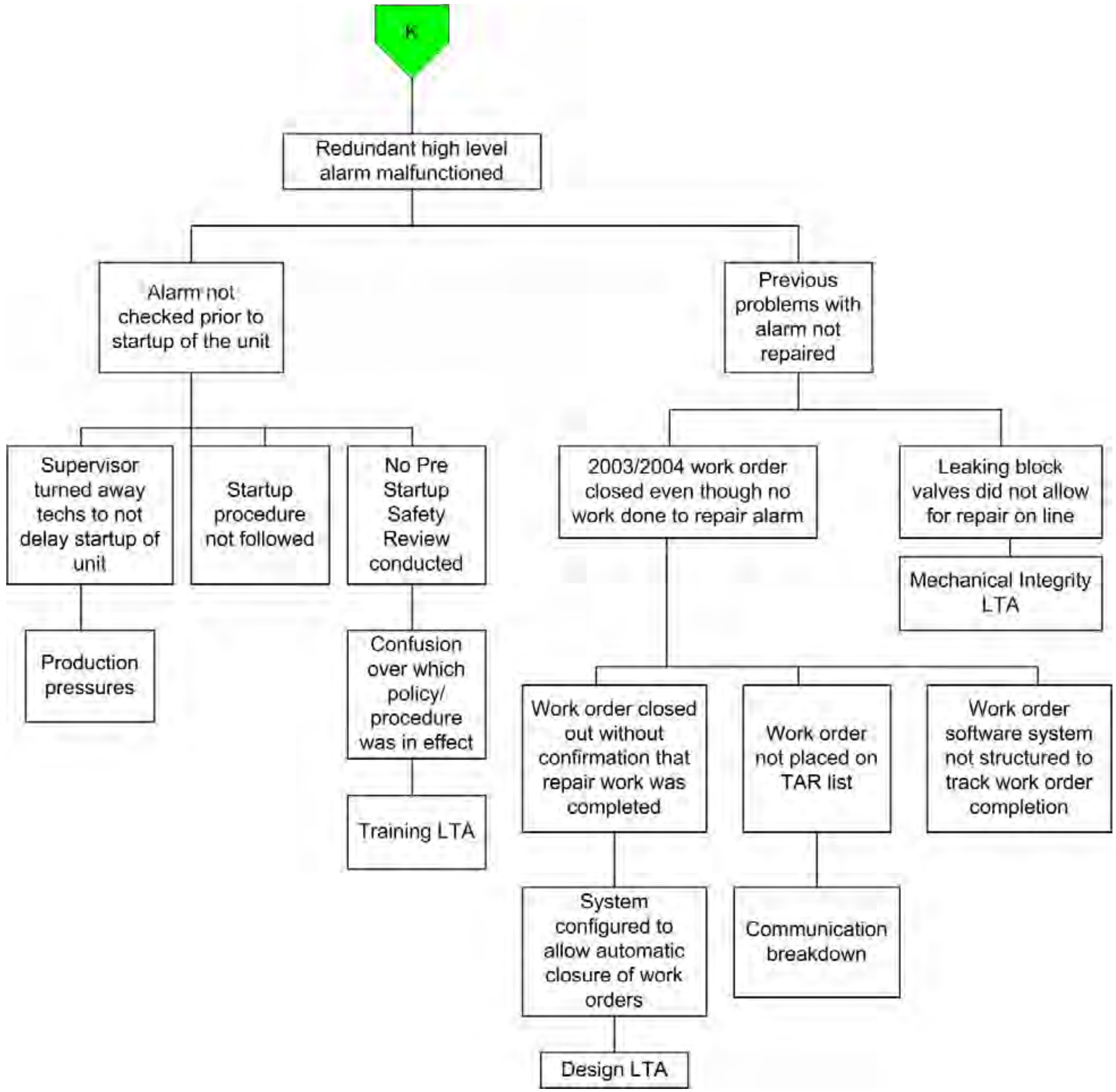

F
Plant personnel did not understand the potential hazards of filling the tower above the range
Procedures do not address a separate filling phase or stopping startup for six hrs. between shifts
Procedures do not address filling level or consequences of deviation
Training LTA
Operating envelope did not address limit on high tower level
Management and Operations staff miscommunicated about the startup of the raffinate, tank availability, and feed routing instructions
Previous deviations were not investigated
Lack of oversight
Lack of reporting of near misses
Definition of near miss vague
Blame and fear of repraisal

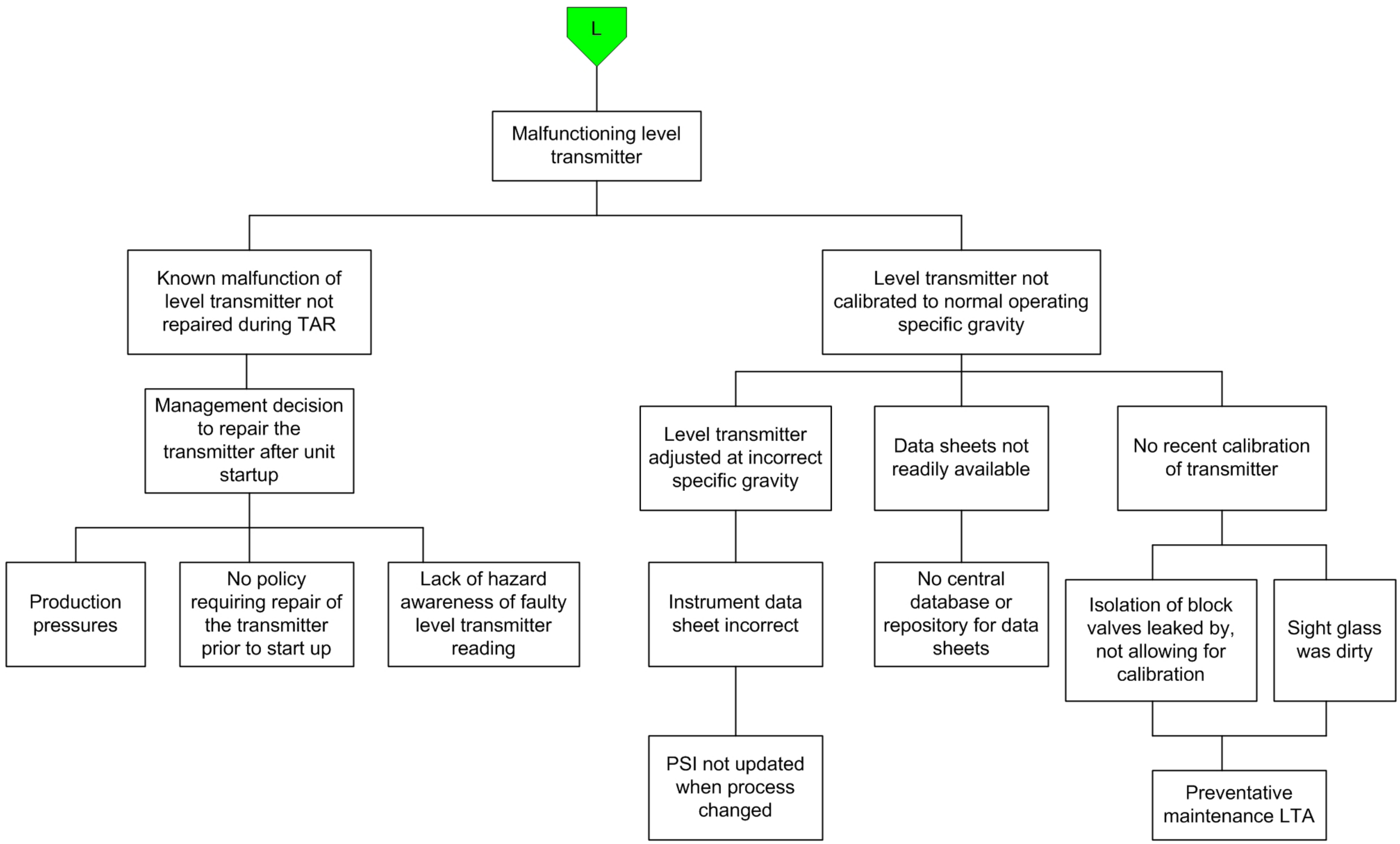

G
Board operator fatigued
Lack of fatigue prevention policy
The splitter tower LCV was not placed in auto mode prior to heater firing per Startup procedure
H
No supervisor or technically trained personnel with ISOM experience in control room during critical period of startup
I
Operator did not understand that the actual tower level was over 100%
Insufficient board operator staffing for startup and upset conditions
M
Board operator believed he was instructed not to remove heavy raff to storage
Board operator did not understand material balance calculations
Tower level indicator never went over 99.9%
Normal
Tower level indication declining during 3-hr. period
L
Redundant high level alarm (LAH-5102) malfunction not known to operators on shift
Alarm did not actuate
K
Board operator believed associated equipment was filling
J
Instructions for Raff rundown not written down in log book, procedures, or elsewhere
Comm btw inside and outside operators LTA
Shift turnover LTA
BP's informal shift turnover procedure for operators was inadequate
Training LTA
DCS system did not provide method to calculate material balance
DCS system did not provide flow in and flow out of unit feed on the same monitor screen

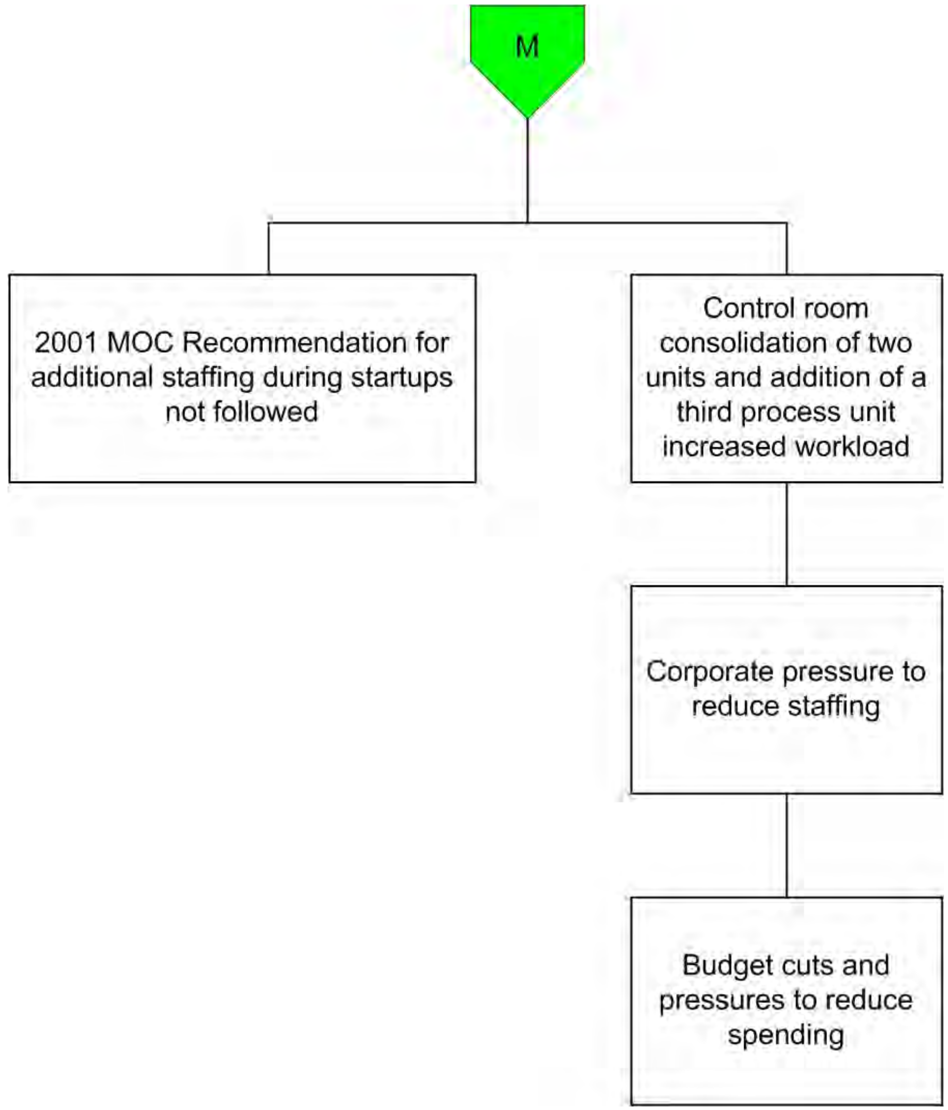

N
Adherence to procedures not strictly enforced
Procedures seen as only guidance by operators
Perception that the startup would run more smoothly in manual
Level biased high to avoid reboiler shutdown & damage
Lack of awareness of hazards
Changes to procedures typically made without evaluation of risk
History of allowing variance to procedures
Lack of mangmt oversight
Procedures stated that the document was a guideline
Procedures were not up dated and were perceived by operators as containing inaccuracies
Production pressures
History of unstable level control
Startups not analyzed
Operating envelope program not fully implemented
MOC procedure not enforced
Action Items from splitter tower MOC procedural changes not implemented
Out-dated procedures certified as up-to-date
Previous incidents not incorporated into training guides, etc. did not address the hazard of putting valve in manual
Consequences of not putting the valve in auto and filling the tower were not provided in the procedures
Lack of management oversight
Person responsible for correcting procedures also responsible for certification of procedures
Inadequate PSM resources – person assigned was overloaded
PSM Coordinator positions not filled
Incident investigations LTA
Procedural development LTA


I
Experienced ISOM supervisor left for family emergency and other experienced supervisor/engineers not available or assigned
Policy requiring presence of knowledgeable supervisor/engineer during startup not followed
Available supervisor inexperienced
Other experienced personnel were troubleshooting another unit
Job requirements and training program for supervisors LTA
Additional staffing not provided
Hazards of ISOM startup underestimated


J
No startup procedures used, initialed, or made available in the main control room during or at end of night shift
No effective shift turnover communications verbally or in the log book btw night and day board operators who started up the unit
Board operator had no startup experience where tower had been filled and pumps shut down prior to his shift
Little information on tower or equipment communicated between board operators starting unit
Night startup activities directed from the satellite control room DCS
Shift turnover LTA
Separate startup phase of filling the tower and shutting down the pumps not in procedures
No formal shift turnover/ communication policy or requirements
No provisions in procedures that address splitting startup activities between two different control rooms
BP's informal shift turnover procedures for operators was inadequate
No formal policy, procedures, or requirements to prevent startup across different control rooms


K
Redundant high level alarm malfunctioned
Alarm not checked prior to startup of the unit
Previous problems with alarm not repaired
Supervisor turned away techs to not delay startup of unit
Startup procedure not followed
No Pre Startup Safety Review conducted
2003/2004 work order closed even though no work done to repair alarm
Leaking block valves did not allow for repair on line
Mechanical Integrity LTA
Production pressures
Confusion over which policy/ procedure was in effect
Training LTA
Work order closed out without confirmation that repair work was completed
Work order not placed on TAR list
Work order software system not structured to track work order completion
System configured to allow automatic closure of work orders
Communication breakdown
Design LTA


L
Malfunctioning level transmitter
Known malfunction of level transmitter not repaired during TAR
Level transmitter not calibrated to normal operating specific gravity
Management decision to repair the transmitter after unit startup
Level transmitter adjusted at incorrect specific gravity
Data sheets not readily available
No recent calibration of transmitter
Production pressures
No policy requiring repair of the transmitter prior to start up
Lack of hazard awareness of faulty level transmitter reading
Instrument data sheet incorrect
No central database or repository for data sheets
Isolation of block valves leaked by, not allowing for calibration
Sight glass was dirty
PSI not updated when process changed
Preventative maintenance LTA


M
2001 MOC Recommendation for additional staffing during startups not followed
Control room consolidation of two units and addition of a third process unit increased workload
Corporate pressure to reduce staffing
Budget cuts and pressures to reduce spending

APPENDIX C: Previously Issued Recommendations

C.1 Safety Culture Recommendation

Whereas:

1. On March 23, 2005, the BP Texas City refinery experienced a severe chemical accident involving a raffinate splitter tower and associated blowdown system that resulted in 15 deaths, about 180 injuries, and significant economic losses, and was one of the most serious U.S. workplace disasters of the past two decades;

2. Key alarms and a level transmitter failed to operate properly and to warn operators of unsafe and abnormal conditions within the tower and the blowdown drum;

3. The startup of the raffinate splitter was authorized on March 23 despite known problems with the tower level transmitter and the high-level alarms on both the tower and the blowdown drum; for example, a work order dated March 10 and signed by management officials, acknowledged that the level transmitter needed repairs but indicated that these repairs would be deferred until after startup;

4. The majority of 17 startups of the raffinate splitter tower from April 2000 to March 2005 exhibited abnormally high internal pressures and liquid levels – including several occasions where pressure-relief valves likely opened – but the abnormal startups were not investigated as near-misses and the adequacy of the tower's design, instrumentation, and process controls were not re-evaluated;

5. Written startup procedures for the raffinate splitter were incomplete and directed operators to use the so-called "3-lb." vent system to control tower pressure, even though the pressure-control

valve did not function in pre-startup equipment checks and also failed to operate effectively during post-accident testing;

6. The Texas City refinery missed opportunities before and after its acquisition by BP North America to connect the tower pressure-relief valves to a safety flare system, as noted in BP's own May 2005 interim investigation report;[244]

7. Most of the fatalities and many of the serious injuries occurred in or around trailers that were susceptible to blast damage and were located within 150 feet (46 m) of the blowdown drum and vent stack;

8. The Texas City refinery had a facility siting policy and performed a management-of-change analysis prior to positioning the trailers, but trailers were nonetheless placed in close proximity to the isomerization unit, which had experienced various hydrocarbon releases, fires, and other process safety incidents over the previous two decades;

9. The Texas City refinery experienced two fatal safety incidents in 2004 as well as a serious furnace fire that resulted in a community order to shelter;

10. Subsequent to the March 23 incident, the Texas City refinery experienced a major process-related hydrogen fire on July 28, 2005, that had the potential to cause additional deaths and injuries and resulted in a Level 3 community alert;[245]

[244] The BP interim report states: "Blowdown stacks have been recognized as potentially hazardous for this type of service, and the industry has moved more towards closed relief systems to flare …. Opportunities to tie the Splitter relief lines into a flare system were not taken when it could have been efficiently done in 1995 or 2002 …."

[245] Level 3 is the second highest emergency classification under Texas City procedures. It applies when "an incident has occurred, the situation is not under control, and protective action may be necessary for the surrounding or offsite area."

11. On August 10, 2005, the Texas City refinery experienced another Level 3 incident involving the Gas Oil Hydrotreater that resulted in a community order to shelter;

12. All three incidents in 2005 raise the issue of the adequacy of mechanical integrity programs at the Texas City refinery;

13. In April 2005 the U.S. Occupational Safety and Health Administration listed the BP Texas City refinery as a subject facility under its Enhanced Enforcement Program for Employers Who Are Indifferent to Their Obligations Under the OSH Act;

14. The U.K. Health and Safety Executive (HSE) investigated and reported on three incidents at the BP Grangemouth refinery in Scotland in 2000, concluding that “BP Group Policies set high expectations but these were not consistently achieved because of organisational and cultural reasons; BP Group and Complex Management did not detect and intervene early enough on deteriorating performance ….”

15. The Board believes that the foregoing circumstances and preliminary findings raise serious concerns about (a) the effectiveness of the safety management system at the BP Texas City refinery; (b) the effectiveness of BP North America’s corporate safety oversight of its refining facilities; (c) a corporate safety culture that may have tolerated serious and longstanding deviations from good safety practice;

16. The Board believes that corporations using large quantities of highly hazardous substances must exercise rigorous process safety management and oversight and should instill and maintain a safety culture that prevents catastrophic accidents;

17. Under 42 U.S.C. §7412(r)(6)(C)(ii), the Board is charged with “recommending measures to reduce the likelihood or the consequences of accidental releases and proposing corrective steps to

make chemical production, processing, handling and storage as safe and free from risk of injury as is possible ….”

18. Board procedures authorize the development and issuance of an urgent safety recommendation before a final investigation report is completed if an issue is considered to be an imminent hazard and has the potential to cause serious harm unless it is rectified in a short timeframe.

Accordingly:

P ursuant to its authority under 42 U.S.C. § 7412(r)(6)(C)(i) and (ii), and in the interest of preventing the serious harm that could result if the imminent hazards underlying the series of incidents at BP facilities are not promptly rectified, the Board makes the following urgent safety recommendation to the BP Group Executive Board of Directors

2005-4-I-TX-R1

1. Commission an independent panel to assess and report on the effectiveness of BP North America’s corporate oversight of safety management systems at its refineries and its corporate safety culture. [246] Provide the panel with necessary funding, resources, and authority – including full access to relevant data, corporate records, and employee interviews – in order to conduct a thorough, independent, and credible inquiry.

2. Ensure that, at a minimum, the panel report examines and recommends any needed improvements to:

[246] Appropriate reference materials for the design of the assessment may include the Final Report of the Columbia Accident Investigation Board (2003), the Conference Board research report *“Driving Toward ‘0’: Best Practices in Corporate Safety and Health*, the ANSI/AIHA Z10-2005 standard *Occupational Health and Safety Management Systems*, the International Labor Organization (ILO) code of practice *Prevention of Major Industrial Accidents* (1991), and the ILO *Guidelines on Occupational Safety and Health Management Systems* (2001).

a. Corporate safety oversight, including the safe management of refineries obtained through mergers and acquisitions;

b. Corporate safety culture, including the degree to which:

i. Corporate officials exercise appropriate leadership to promote adherence to safety management systems;

ii. Process safety is effectively incorporated into management decision-making at all levels;

iii. Employees at all levels are empowered to promote improved process safety;

iv. Process safety programs receive adequate resources and are appropriately positioned within organizational structures;

c. Corporate and site safety management systems, specifically:

i. Near-miss reporting and investigation programs;

ii. Mechanical integrity programs;

iii. Hazard analysis programs, management-of-change programs, and up-to-date operating procedures for processes with catastrophic potential;

iv. Siting policies for occupied structures near hazardous operating units.

3. Ensure that the panel has a diverse makeup, including an external chairperson; employee representatives; and outside safety experts, such as experts in process safety; experts in corporate culture, organizational behavior, and human factors; and experts from other high-risk sectors such as aviation, space exploration, nuclear energy, and the undersea navy.

4. Ensure that the report and recommendations of the independent panel, which should be completed

within 12 months, are made available to the BP workforce and to the public.

C.2 Trailer Siting Recommendation

Whereas:

1. On March 23, 2005, the BP Texas City refinery experienced a severe explosion and fire accident involving a raffinate splitter tower within the isomerization (ISOM) unit and associated blowdown system that resulted in 15 deaths, 180 injuries, and significant economic losses; the accident was one of the most serious U.S. workplace disasters of the past two decades.

2. All of the fatalities and many of the serious injuries occurred in or around the nine contractor trailers that were sited near process areas and as close as 121 feet (37 m) from the ISOM unit. This unit contained large quantities of flammable hydrocarbons and had a history of releases, fires, and other safety incidents over the previous two decades.

3. Workers in adjacent units were injured in trailers as far as 480 feet (146 m) from the ISOM blowdown drum. A number of trailers as far as 600 feet (103 m) from the blowdown drum were heavily damaged.

4. At the Texas City refinery, trailers had been periodically sited in and around hazardous process areas for reasons of convenience such as ready access to work areas. The trailers did not need to be located as close as they were to the process areas in order for workers to perform their job duties.

5. Trailers had been sited periodically in the same location near the isomerization unit for a number of years. On September 1, 2004, and prior to a safety assessment, BP placed the trailer where 12 workers died near the isomerization unit; a month later BP applied a siting policy to approve the location. The eight other trailers placed nearby were not analyzed for hazards related to their

location, nor was the impact of the total occupancy of multiple trailers in close proximity considered.

6. Under BP's siting policy, trailers used for short periods of time such as turnaround trailers were considered as posing little or no danger to occupants. This approach conforms to the guidance provided in American Petroleum Institute (API) Recommended Practice 752, "Management of Hazards Associated with Location of Process Plant Buildings." API 752 states that each company may define its own risk and occupancy criteria.

7. API 752 is a widely recognized practice for complying with facility siting requirements under the Process Hazard Analysis element of OSHA's Process Safety Management Standard (29 CFR 1910.119).

8. API 752 provides no minimum safe distances from hazardous areas for trailers used in refineries and other chemical facilities. Trailers are not generally designed to protect the occupants from the fire and explosion hazards present in refineries. In contrast, occupied buildings (e.g. control rooms, operator shelters) located within a process unit are typically permanent and constructed to be blast and fire resistant.

9. Trailers can be easily relocated to less hazardous sites. Subsequent to the March 23rd incident, BP America Inc. announced that it would move trailers at least 500 feet (152) from hazardous process areas. A number of contractor offices were moved to an offsite location.

10. In 1995, another serious process plant incident involved occupied trailers placed too close to hazardous areas, resulting in significant deaths and injuries. At the Pennzoil Refinery in Rouseville, Pennsylvania, a hydrocarbon fire that resulted from the bursting of two storage tanks led to five fatalities, including two contractors who were in trailers sited near the tanks. A 1998 EPA investigation report determined that if the trailers had been isolated from the storage tank

area the casualties may have been prevented.

11. Under 42 U.S.C. §7412(r)(6)(C) (ii), the Board is charged with "recommending measures to reduce the likelihood or the consequences of accidental releases and proposing corrective steps to make chemical production, processing, handling and storage as safe and free from risk of injury as is possible …."

12. Board procedures authorize the issuance of an urgent safety recommendation before a final investigation report is completed where there is likelihood that a safety issue is widespread at a number of sites.

Accordingly:

Pursuant to its authority under 42 U.S.C. §7412(r)(6)(C)(i) and (ii), and in the interest of promoting safer operations at U.S. petrochemical facilities and protecting workers and communities from future accidents, the Board makes the following urgent safety recommendations:

American Petroleum Institute

2005-4-I-TX-R2 In light of the above findings concerning the March 23rd incident at BP's Texas City refinery, revise your Recommended Practice 752, "Management of Hazards Associated with Location of Process Plant Buildings" or issue a new Recommended Practice to ensure the safe placement of occupied trailers and similar temporary structures away from hazardous areas of process plants. Ensure that the new recommended practice:

a. Protects occupants from accident hazards such as heat, blast overpressure, and projectiles;

b. Establishes minimum safe distances for trailers and similar temporary structures away from hazardous areas of process plants;

c. Evaluates the siting of trailers under a separate methodology from permanent structures, since trailers are more susceptible to damage, are more readily relocated, and likely do not need to be placed near hazardous areas.

American Petroleum Institute & the National Petrochemical and Refiners Association

2005-4-I-TX-R3 Issue a safety alert to your membership to take prompt action to ensure the safe placement of occupied trailers away from hazardous areas of process plants.

C.3 Blowdown Drum & Stack Recommendation

Key Findings

1. On March 23, 2005, the BP Texas City refinery experienced a severe explosion and fire that resulted in 15 deaths, 180 injuries, and significant economic losses; the accident was one of the most serious U.S. workplace disasters of the past two decades.

2. During the isomerization (ISOM) unit startup, a distillation tower was overfilled with liquid, triggering the opening of three emergency relief valves that protect the tower from high pressure; the liquid discharged into a disposal blowdown drum with a stack open to the atmosphere. The drum rapidly overfilled with flammable liquid leading to a geyser-like release out of the stack and subsequent explosion and fire.

3. The ISOM blowdown drum was connected to 58 emergency relief valves. BP had not completed a relief valve and disposal collection piping study for the ISOM which was necessary to determine if the drum was adequately sized. At the time of the incident, many BP Texas City refinery process units did not have up-to-date relief studies. In addition, information on the

original design basis and capacity of the ISOM blowdown drum was missing. CSB determined that liquid was released out the top of the ISOM blowdown stack during the incident because the drum was undersized.

4. From 1994 to 2004, there were eight serious ISOM blowdown incidents; in two of these incidents the blowdown stack caught fire. The other six incidents were serious near-misses where flammable hydrocarbon vapors that were released from the blowdown system could have had catastrophic consequences if the resulting ground level vapor clouds had found sources of ignition.

5. The BP Texas City refinery safety standards, in effect since 1977, stated that new blowdown stacks were not permitted and blowdown drums should be connected to a closed system or a flare when the existing facility was outgrown or major modifications were made to the unit. Since 1986 the blowdown drum was replaced and major capacity changes were made but the blowdown drum was not connected to a safe disposal system such as a flare. In 2002, BP engineers proposed connecting the discharge from the ISOM relief valves to a flare as part of an environmental project, but this work was not performed. A properly designed flare system would safely contain discharged liquid in a disposal drum and burn flammable vapor preventing a hazardous release to atmosphere. Flares are the most frequently used disposal control equipment in the oil refining industry.

6. As a result of mergers and acquisitions with Amoco and Arco, BP owns five North American refineries. Prior to the incident, the five refineries operated 22 blowdown systems with stacks open to atmosphere; 17 handled flammables. Since the March 23, 2005 accident, BP has stated it will eliminate all atmospheric blowdown systems in flammable service at all five of its U.S. refineries including Texas City.

7. OSHA’s Process Safety Management (PSM) standard establishes requirements for the prevention of catastrophic releases of highly hazardous chemicals such as flammables. The standard requires employers of covered processes to compile written process safety information including information pertaining to relief system design and design basis that complies with “recognized and generally accepted good engineering practices.” OSHA publishes PSM Compliance Guidelines that establish procedures for the enforcement of the standard. These guidelines call for inspections to ensure that “destruct systems such as flares are in place and operating” and “pressure relief valves and rupture disks are properly designed and discharge to a safe area.”

8. In 1992, the Occupational Safety and Health Administration (OSHA) cited and proposed fines to Amoco on the hazardous design of a similar blowdown drum and stack at the Texas City refinery. OSHA determined that the drum and stack were not constructed in accordance with the American Society of Mechanical Engineers’ (ASME) Boiler and Pressure Vessel Code. The code requires relief valve piping to discharge to a safe location. As an abatement method OSHA suggested connecting the blowdown drum to a closed system such as a flare. Amoco asserted that the blowdown system was constructed in accordance with industry standards citing the American Petroleum Institute’s (API) Recommended Practice 521 Guide for Pressure-Relieving and Depressuring Systems. As part of a settlement agreement, OSHA withdrew the citation and the fine. The refinery continued to use blowdown drums without flares at the Texas City site. As a result of the March 23, 2005 incident, OSHA cited BP’s ISOM blowdown system for a willful violation of the same regulation. In the settlement agreement, BP agreed to permanently remove the ISOM blowdown system from service.

9. API 521 is the generally accepted practice for the design and operation of pressure relieving and disposal systems. CSB found that for flammables API 521:

   a. Does not consider liquid overfill of a vessel as a potential hazard which can result in large liquid releases to pressure relief and disposal systems;

b. Lacks adequate drum sizing guidance for large releases of liquid to disposal systems;

c. Does not address the hazard posed by relief flows less than design causing flammable concentrations of vapor at ground level due to low stack exit velocity and ineffective dispersion;

d. Does not recommend the use of inherently safer options such as a flare system in lieu of a blowdown drum and stack vented to the atmosphere.

Therefore, the Board makes the following safety recommendations:

American Petroleum Institute

2005-4-I-TX-R4 Revise API Recommended Practice 521, Guide for Pressure Relieving and Depressuring Systems to ensure that the guidance:

a. Identifies overfilling vessels as a potential hazard for evaluation in selecting and designing pressure relief and disposal systems;

b. Addresses the need to adequately size disposal drums for credible worst-case liquid relief scenarios, based on accurate relief valve and disposal collection piping studies;

c. Warns against the use of atmospheric blowdown drums and stacks attached to collection piping systems that receive flammable discharges from multiple relief valves and urges the use of appropriate inherently safer alternatives such as a flare system.

Occupational Safety and Health Administration (OSHA)

2005-4-I-TX-R5

1. Implement a national emphasis program for all oil refineries that focuses on:

    a. The hazards of blowdown drums and stacks that release flammables to the atmosphere instead of to an inherently safer disposal system such as a flare. Particular attention should be paid to blowdown drums attached to collection piping systems servicing multiple relief valves;

    b. The need for adequately sized disposal knockout drums to safely contain discharged flammable liquid based on accurate relief valve and disposal collection piping studies.

2. Urge States that administer their own OSHA plan to implement comparable emphasis programs within their respective jurisdictions.

APPENDIX D: BP Corporate and Texas City Refinery Background

D.1 BP- Amoco Merger

The management structure changed on December 31, 1998, when Amoco Corporation merged with BP. The new company, BP-Amoco, transferred corporate functions from Chicago to London. The process safety group in Chicago was disbanded and the process safety function was placed under the Technology area in the London corporate office staffed by a single advisor. About 120 new business units were created, one of which was the Texas City refinery, now headed by a Business Unit Leader who was the Amoco refinery manager before the merger. In 2000, after reorganization, the PSM department reported to the manager of engineering and inspection rather than the chair of the Refinery Process Safety Committee.

D.2 BP South Houston Integrated Site

In 2001, the Star Site concept[247] was introduced at Texas City. The refinery and nearby chemical plants were merged into a single business unit at Texas City, managed by a site director (the former Texas City refinery Business Unit Leader), who now reported to both the refining and chemicals groups. A new refinery manager assumed responsibilities for the Texas City refinery. As the products of the ISOM unit were used primarily in the chemicals business, management of the ISOM unit was transferred from the refinery to the chemicals business. A new shared services group provided EHS (Environment, Health and Safety), process safety, human resources, information technology, and contract maintenance for these facilities. Until new corporate standards could be developed and adopted, each business in it continued to use the corporate standards that were in effect in their respective organizations before the merger. At the end of 2001, the site director left to become the Business Unit Leader of another BP refinery, and a new site director arrived from London. At the Texas City refinery, the refinery manager retired and was

[247] This concept had been previously used by BP at its Grangemouth facility in England.

replaced by a Performance Unit Leader, who reported to both the BP South Houston site director and the refining group VP.

D.3 BP Texas City Refinery

In April 2004, BP moved most of its petrochemicals businesses into a separate entity, which resulted in chemical operations being separated from the refinery and the shared services group being divided among these entities. Management of the ISOM unit was returned to the refinery. In June 2004, the Performance Unit Leader left to become a Business Unit Leader of another BP refinery because the position was being eliminated. The BP South Houston site director became the Business Unit Leader of the Texas City refinery, and in January 2005, began reporting solely to the Regional Group VP of Refining. The PSM department became part of the refinery HSSE department.

APPENDIX E: ISOM Unit - History, Equipment, and Operation

The ISOM unit began production in 1985 to provide higher octane for blending stock of unleaded gasoline that was lost with the government phase-out of tetra ethyl lead. As the ISOM unit was converted from a process unit, called an Ultraformer, its process equipment (towers, drums, piping, etc.) ranged from newer equipment installed when the conversion was made to older equipment that had been installed in the 1950s.

In 1985, Ultraforming Unit No. 1 was converted into a 27,000 bpd C_5/C_6 naphtha isomerization unit. The isomerization process used was the Hysomer process licensed by Union Carbide Corporation. The Hysomer process converts lower octane C_5 and C_6 straight chain paraffins to higher octane C_5 and C_6 isomers on a platinum-alumina catalyst.

In mid-1986, the ISOM unit was converted from the Union Carbide Hysomer process to the Universal Oil Products (UOP) low-temperature Penex process. The new Penex unit consisted of three sections: the Ultrafiner section, Penex Reaction system, and Stabilization section. The design basis of this unit was 27,000 bpd.

E.1 Raffinate Splitter Section

This equipment was installed in 1976 and used initially as a Heavy Ultraformate Fractionator (HUF) to increase recovery of xylenes from ARU and Ultraformers. In 1985, the HUF was converted to fractionate light raffinate feedstock for the ISOM unit and became a raffinate splitter. In 1986, the capacity of the raffinate splitter section was increased from 20,000 to 30,000 bpd to ensure that 27,000 bpd would be available as feed for the Penex section of the ISOM unit. In 1987, the capacity of the raffinate splitter section was again increased from 30,000 to 33,000 bpd to produce additional heavy raffinate for JP-4 jet fuel.

When the raffinate splitter tower was converted to a raffinate splitter in the mid-1980s, its operating pressure was changed to 75 psig (517 kPa) and the discharge pressure for the opening of one safety relief valve was set at 70 (483 kPa), while the other two relief valves were set at 74 psig each (510 kPa). In March 2004, after an inspection revealed significant corrosion under the insulation on the exterior of the raffinate splitter, its relief pressure was lowered to 40 psig (276 kPa), and the pressures for the opening of the three safety relief valves were lowered to 40, 41, and 42 psig (276, 283, and 290 kPa), respectively.

E.2 Blowdown Drum and Stack

The ISOM blowdown drum and stack was originally installed in the mid-1950s as part of Ultraformer No. 1 unit. A piping and instrumentation diagram (P&ID) indicates that the blowdown drum was initially located in the southwest corner of the Ultraformer No. 1 unit. In May 1957, an inspection record noted that the blowdown drum and stack was “relocated approximately 200 feet (61 m) to the extreme northwest corner of the battery limits. This vessel was moved to eliminate a dangerous fire hazard which prevailed under certain wind conditions.” The inspection record also noted that three new nozzles were installed on the drum to facilitate new line tie-ins from ultraformate splitting facilities; however, despite this additional load, BP has indicated that no documented capacity analysis could be found.

The operating manual for the HUF, dated June 1976, lists the blowdown connections to the Ultraformer No. 1 blowdown drum for “receiving, quenching and disposing if hot liquid and/or vapor hydrocarbons.” BP has not provided the CSB with any historical records from the Texas City refinery to indicate that the blowdown drum and stack was capable of safely handling the load from the listed connections.

In October 1986, an engineering contractor working on converting the ISOM unit to Penex evaluated the relief system on the raffinate splitter and determined that the backpressure in the common relief valve disposal header was 113 percent of the relief valve set pressure in the event of a reflux/condenser failure, and recommended that Amoco take corrective action. An undated internal Amoco memo, with some handwritten notes, indicates that Amoco was informed of the problem and developed some proposals to correct it, but none were implemented.

In 1992, an action item from the ISOM unit's initial PHA required by PSM recommended that relief valves be reviewed to ensure that they were properly sized. In March 1994, the recommendation was that no changes were required to the ISOM unit's pressure relief header system of blowdown drum, based on an Amoco engineering analysis. However, the engineering analysis did not look at the common vent disposal header from the raffinate splitter, nor did it consider two-phase discharges (vapor/liquid) to the blowdown drum and how effectively the drum could handle them.

In 1994, P&ID drawing[248] changes show that a number of new lines were added to the relief valve headers; however, BP has provided no historical records to the CSB to indicate that any of the safety and health impacts of these changes were evaluated under the MOC process.

In 1997, the refinery replaced the blowdown drum and stack because it was about 40 years old and needed extensive repair due to corrosion. Part of the decision to replace the blowdown drum without modifications was to "maintain profits" so the refinery could "continue to operate without triggering the EPA New Source Performance Standards."[249] However, while the blowdown system replacement was listed as a "replacement-in-kind," the stack on the new blowdown drum was fabricated to be 34 inches outside diameter, while the stack on the original blowdown drum was 36 inches inside diameter.

During the ISOM PHA revalidation in 1998, an action item recommended locking the valve on the blowdown drum overflow line open to prevent excessive backpressure on the common disposal headers in the event of a large flow of liquid to the drum. This action item was resolved by chaining the valve open; however, no MOC was conducted to evaluate the safety or health implications of this change.

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[248] Drawings B-4450-G_1278, Rev. 27; B-4550-G-2636; B-4550-G-2746; and B-4550-G-2622, Rev. 6.

[249] Amoco Appropriation Request No. 08-05449; Reforming--ISOM--Replace F-20 Blowdown Drum and Stack; July 7, 1997.

Section IV of the *Isomerization Unit No.1 Operating Manual* and the *ISOM #1, Training Guide #31, Pumpout and Blowdown Systems* explain that originally, the drum and stack had quench water and steam connections. The quench water would cool any hot process streams. A temperature-sensing element connected to a flow control valve would admit water to the drum. Operators could also manually add quench water. Two steam connections were also provided: one to steam out the drum, and the other, to blanket the drum and disperse vapors that vent from the stack. This equipment had not been operational for several years prior to the incident, according to interviews with ISOM operators.

In 2003, an internal inspection of the blowdown drum revealed that most of the vessel shed trays had collapsed in the bottom of the drum. As the remaining shed trays that were still attached were considered dangerous to personnel, the internal inspection was terminated and the drum was closed without recommending that the drum be taken out of service or repaired.

Later in 2003, the second PHA revalidation for the ISOM unit contained an action item that recommended a full unit relief valve study be conducted to verify that all relief valves were adequately sized for service. The relief valve study was underway when the explosion occurred in the ISOM unit two years later.

APPENDIX F: Trailers for Turnaround Activities

Contractors working on the Motorization Project were working out of a wood-framed, double-wide office trailer sited west of the ISOM unit and north of the catalyst warehouse, about 120 feet (37 m) from the blowdown drum. This location was selected because trailers had been sited in this area during an earlier turnaround and it was adjacent to the ULC unit where the work would be performed. The double-wide trailer was sited in this area in September 2004, had 11 contractor offices, and was routinely used for meetings. This trailer was to be occupied until the project was completed in June 2005.

A single-wide, wood-framed office trailer, used by four QA/QC contractors, was sited south of the double-wide and east of the catalyst warehouse, approximately 136 feet (42 m) from the blowdown drum. This trailer was installed when the ULC turnaround began and was to be occupied until the turnaround was complete. Both trailers had electrical hook-ups, and the double-wide project trailer also had a potable water hook-up.

Six additional trailers, arranged in two parallel rows of three, were sited directly north of the catalyst warehouse approximately 250 feet (76 m) from the blowdown drum. All had electrical hook-ups.

The two southernmost trailers in this group of six were being used by an instrument and electrical contractor who had between 15 to 20 employees working on the ULC turnaround. One trailer was used primarily by contractor job representatives while the other was an employee break/lunchroom. Both, sited in early January, were single-wide of wood construction and were scheduled to remain until the contractors' work was completed.

The middle two trailers in the group of six were being used as decontamination trailers for a contractor changing reactor catalysts in the ULC. One contractor employee was assigned to this trailer to issue and wash work clothing; other contractor employees used it to change and/or shower at the beginning and end of their work shifts. These were both single-wide with steel fames and siding. These trailers had been sited in early February and would remain until the catalyst was changed in ULC reactors.

The two trailers at the northernmost end of the group of six, constructed of steel, were sited in mid-February. These trailers, scheduled to remain for several weeks, were being used by other ULC contractors to store equipment and tools; one had an attendant.

F.1 BP Internal Guidelines Compared To Good Practice Guidelines

The CSB determined that the Amoco siting workbook used a less conservative correlation for death to occupants than did API 752. The Amoco workbook shows lower death rates at comparable pressures than does API. For example, API states that a 1.0 psi peak side-on pressure applied to a wooden building will result in a 10 percent death rate to the occupants, whereas Amoco states that a 5.0 psi. reflected pressure (approximately equivalent to a 2.5 psi peak side-on pressure) will produce the same rate. The overpressure experienced at the two trailers closest to the blowdown drum was estimated to be between 2.5 and 2.8 psi peak side-on pressure.

The building identification step of the Amoco workbook consists of initially identifying those buildings that can be screened out from further analysis. Buildings can be exempted from further analysis based on their location, construction, or occupancy. The workbook notes that minimum damage will result if a building is located “far enough” away from a vapor cloud explosion and provides minimum distances between buildings and processing units. The workbook states that trailers can be located 350 feet (107 m) from the center of the nearest concentration of congested equipment in the closest unit, which was generally interpreted at the refinery to mean that trailers could be located 350 feet (107 m) from the unit’s battery limits. Steel frame buildings with sheet metal siding could be located 450 feet (137 m) from the unit’s battery limits and concrete, masonry, brick, or cinder block buildings could be located 700 feet (213 m) away. The workbook notes that the minimum distance for trailers was less than for other types of buildings because "data from actual events indicate that trailers tend to roll in response to a vapor cloud explosion, and walls and roof do not collapse on occupants, resulting in fewer serious injuries/fatalities."

The basis for the safe distance used in the Amoco workbook adopted by BP was documented in the Amoco Petroleum Products Sector-Refining *Facility Siting Reference Manua*l (Amoco 1995b). A typical volume of congested equipment was calculated to be 200 million standard cubic feet (mscf). Using this typical congested equipment volume, the distances that resulted in a 10 percent occupant death rate for various building types were calculated, then recorded in the workbook. The CSB determined that these distances placed trailers at an increased risk from vapor cloud explosions.

F.1.1 Occupancy Criteria

The workbook also set occupancy limits, which would exclude further screening. A building was excluded from further analysis if one individual occupied it for 20 hours per week or less, or if all inhabitants occupied it less than 200 hours per week. The workbook instructed users to calculate occupancies on an annualized basis. For trailers occupied only a couple of months during a unit turnaround, this approach diluted the actual risks to the occupants by weighting them (assuming zero risk for the months that the trailer was not being used) over a yearly average. Consequently, nearly all trailers at the refinery were excluded from further screening based on their annualized occupancy levels. The Amoco workbook also noted some factors to consider when determining peak occupancy levels, including meetings and gatherings, but did not provide any guidance on what to do if the peak occupancy was exceeded. In the March 2005 explosion, a total of 22 BP and contractor workers were inside a double-wide trailer located 120 feet (37 m) from the blowdown drum because of a weekly meeting. The normal occupancy of the trailer was 13. When this trailer was destroyed by the blast overpressure wave from vapor cloud explosion, 12 were killed in or around the trailer and the other 10 seriously injured.

APPENDIX G: Process Modeling

The CSB examined the mechanisms responsible for the overflow of the raffinate splitter column into its overhead vapor line and to model the column conditions leading to the overfilling of the column.

G.1 Modeling Approach

Convention distillation models are inappropriate for modeling the behavior of the raffinate splitter column during this incident because distillation was not occurring. By 1:13 p.m. on March 23, 2005, the column was completely liquid-full (flooded) with a layer of sub-cooled liquid at the top and downstream equipment filled with nitrogen. No vapor flowed out of the column, no condensation occurred in the fin fan condenser, and no reflux flowed to the column. Laboratory tests of liquid samples recovered from the column feed, bottoms, and overhead confirmed that no separation had occurred in the column (SPL Houston Laboratories, 2005). Furthermore, the behavior of the vapor generated in the column on the flooded trays can not be predicted with confidence, as the conditions are outside the range of standard empirical models of distillation tray behavior. Standard steady-state and dynamic distillation computer programs cannot accurately model the behavior of the column under these conditions.

Three complementary approaches were used to understand the overflow of the raffinate splitter column:

- modeling of column material balance,
- modeling of liquid thermal expansion, and
- qualitative evaluation of vapor accumulation.

The material balance was modeled in a spreadsheet based on flow data from the PI system[250]. The density of the liquid in the column was modeled using the Rackett equation and temperature data from the PI

[250] The PI System, or Process Information System, is a historical database of process data collected from the control board.

system. The potential for vapor accumulation was inferred qualitatively from PI system pressure and temperature data, and from experimental bubble point[251] test data obtained from Fauske & Associates (2005).

A simplified composition (Table G-1) was used to make property calculations tractable. This composition gave a very good fit to Fauske & Associates' experimental bubble point data (Figure G-1). This data is based on analysis of samples taken from the raffinate splitter column overheads and was developed using Fauske & Associates' proprietary VSP-2 test apparatus.

Table G- 1. Raffinate splitter column simplified composition model (Fisher, 2006)

Compound	Weight Fraction
n-pentane	0.0383
2-methyl butane	0.0263
n-hexane	0.1519
2-methyl pentane	0.2950
n-heptane	0.3072
n-octane	0.1300
n-nonane	0.0409
Heavies as n-decane	0.0104
Total	1.0000

[251] Mixtures at a given pressure boil over a range of temperatures, with the most volatile materials vaporizing first and the least volatile last. The bubble point, or initial boiling point, of a mixture at a given pressure is the temperature at which vaporization first occurs.

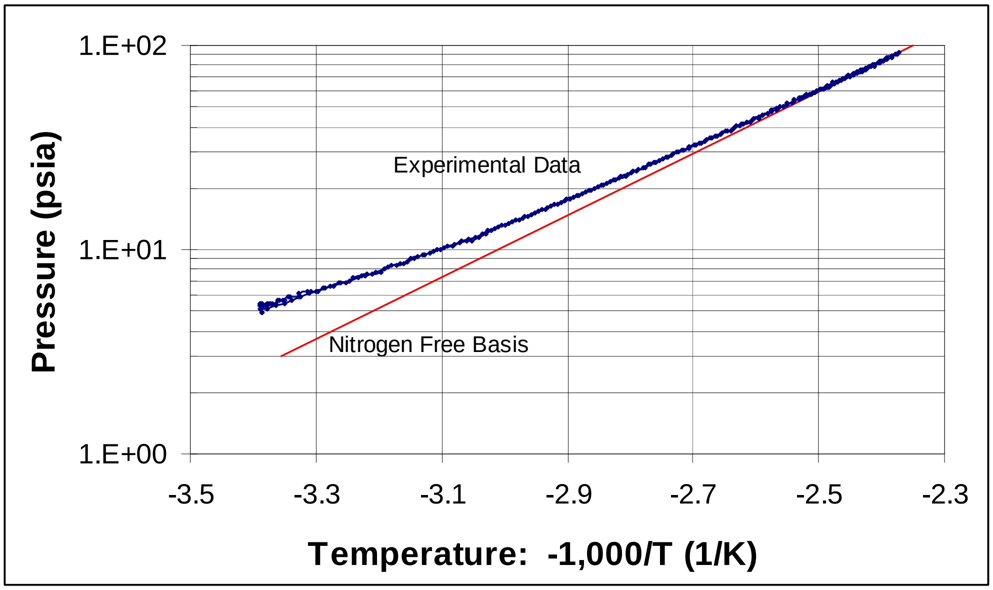

Figure G- 1. Experimental boiling (bubble) point data (Fauske & Associates, 2005)

G.2 Raffinate Splitter Column Overfill

Based on material balance, at 1:13 p.m., the level of cold liquid in the raffinate splitter would have been 143 feet (44 m) above the lower tangent line on the column. Accounting for liquid thermal expansion due to the heating of the column contents (but neglecting vapor holdup in the column) brings this to 161 feet (49 m), less than 4 feet (1.2 m) below the upper tangent line of the column. This left only about 3.5 percent of the volume of the column empty; the liquid level was reaching the top of the column. Sufficient vapor had accumulated lower in the column to displace the cold liquid at the top into the overhead vapor line.

Vapor generated in the reboiler initially had a minor effect on column level. The pressure in the lower column, created by the combination of nitrogen pressure at the top of the column and the hydrostatic pressure exerted by the liquid filling the column, raised the boiling point of the liquid enough to suppress bubble formation. Any bubbles formed quickly collapsed when they contacted relatively cold liquid a short distance higher in the column.

This situation changed in the minutes preceding the incident. At 12:41 p.m., operators opened the 8-inch valve around the column relief valves to vent nitrogen from the column, reducing the pressure from 33 to less than 22 psig (152 kPa), and coincidentally reducing the boiling point temperature of the liquid throughout the column. Heavy raffinate flow began at 12:59 p.m., rapidly preheating the feed to the column to 260^{0}F (127°C), well above its initial boiling point temperature.

Between 12:59 and 1:13 p.m., the average temperature of the column increased almost 27^{0}F (-0.3°C). As the amount of sub-cooled liquid below the feed tray decreased, vapor bubbles that had formed in the reboiler no longer quickly collapsed. Consequently, the vapor volume in the column increased, although a "cap" of cold liquid remained in the upper column. Less than 0.1 percent of the liquid in the column had to vaporize to displace the column contents into the overhead vapor line. The trend in the column strongly favored significant liquid swell due to vapor hold-up in the column at the time of the incident.

G.3 Blowdown Stack Hydrocarbon Liquid Overflow

The amounts of sub-cooled hydrocarbon liquid lost from the raffinate splitter to the atmosphere and sewer can only be estimated. A mass balance of the raffinate splitter, ancillary equipment, blowdown drum, and piping using calculated flows from the safety relief valves on the raffinate splitter overhead vapor line and flow to the sewer from the gooseneck piping at the bottom of the blowdown drum was used to determine the flow from the blowdown drum stack to the atmosphere.

G.3.1 Methodology

A digital computer simulation program calculated the flows of sub-cooled liquid through the safety relief valves, relief header, sewer pipes, and blowdown drum. The computer program incorporates technology from the American Institute of Chemical Engineers (AIChE); Design Institute for Emergency Relief Systems (DIERS); and Center for Chemical Process Safety (CCPS) for both viscous and non-viscous, flashing, frozen, and hybrid two-phase flows through emergency relief devices and pipes. Also included are routines to calculate inlet pipe pressure drop and discharge pipe back pressure for choked and sub-critical vapor, two-phase and sub-cooled liquid flows from safety valves. The computer program reports choked or unchoked and turbulent or laminar flow through each device and associated back pressures through inlet or discharge pipes. Warning messages are provided if the emergency relief devices cannot maintain the system pressure to meet American Society of Mechanical Engineers' (ASME) Pressure Vessel Code and API requirements.

G.3.2 Computer Inputs and Assumptions

The three Consolidated bellows safety relief valves protecting the raffinate splitter had coefficients of discharge and rated capacity flows as Table G-2 shows.

Table G-2: Safety relief valve characteristics

Safety Relief Valve	Vapor Flow	Liquid Flow
Kd	0.95	0.74
Rated Capacity	1.1 Pset	1.25 Pset

A Kp factor is applied to a safety relief valve with vapor trim when flowing a liquid. The flow from these valves therefore increases from 0.6 to 1.0 of the rated capacity as the flowing pressure increases from 1.1 to 1.25 Pset. When the flowing and constant superimposed backpressures on the safety relief valves exceed certain values, Kb and Kw factors are also applied to reduce the vapor or liquid flows, respectively, to account for the valves going out of full lift. The Kb and Kw values in API 520 are consensus values of various manufacturers. Each manufacturer also publishes Kb and Kw curves for its own valves. A single curve represents the performance of all models in a manufacturer's line of valves. These values were supposedly measured, but most of the data are not now available to justify the published curves. The published values of the various manufactures do not agree.

Safety relief values with modified liquid trim are now required by the ASME Code to have their rated capacity flow certified at 1.1 Pset. The manufacturers, however, have never changed the Kw curves published for their older model liquid valves with the rated capacity certified at 1.25 Pset. Due to the high overpressure of the liquid flow from the safety relief valves, a Kw value of 1.0 was chosen to best represent the incident information.

A certain degree of uncertainty therefore exists with respect to the flows and backpressures calculated for the safety relief valves protecting the raffinate splitter. The uncertainty of the flow into the blowdown drum affects the calculated liquid flows to the sewer through the gooseneck piping and to the atmosphere from the stack and available to form the flammable vapor cloud. The flows reported here are therefore best estimates that agree with the incident timeline and eyewitnesses accounts of the release from the blowdown drum stack.

G.3.3 Computer Simulation Results

The overall mass balance of hydrocarbon flow from the raffinate splitter from the computer simulation is shown in Table G-3. As much as 6,730 gallons of hydrocarbons could have been released to the atmosphere prior to the explosion and an additional 855 gallons after the explosion.

Table G-3: Overall mass balance of hydrocarbon flow from the raffinate splitter

Equipment	Volume (Gallons)	Mass (pounds)	Time to Fill (minutes)
Flow from raffinate splitter tower	51,930	283,150	6.00
Raffinate splitter safety relief valve discharge pipe header	6,975		0.625
Blowdown drum and stack (above gooseneck nozzle)	18,855		2.70
Other safety relief valve discharge pipe headers	6,300		0.900
Flow to fill equipment	32,130	175,200	4.225
Flow to sewer	12,210	66,575	5.375
Flow to atmosphere	7,590	41,375	1.775
Before explosion (94.5 seconds)			
Flow to sewer	11,470	62,555	
Flow to atmosphere	6,735	36,710	
After explosion (12 seconds)			
Flow to sewer	740	4,020	
Flow to atmosphere	855	4,665	
Total	19,800	107,950	

APPENDIX H: Blast Damage Analysis, Vapor Cloud and Explosion Modeling

The CSB conducted surveys and analyzed on- and off-site blast damage resulting from the March 23, 2005, explosion at the BP Texas City refinery. The CSB engaged a contractor to perform engineering analysis and modeling to investigate the release and explosion consequences of the generated vapor cloud. Various explosion scenarios were examined using computer simulations for comparison with observed consequences, and blast contours were calculated. Animations were developed that depict a best estimate of events, including dispersion of flammables and propagation of flame through the flammable cloud and creating the explosion. A final report was submitted to the CSB containing the information collected, completed analysis, and results; highlights of the report appear in the following sections of this appendix (ABS Consulting, 2006). Animations showing the dispersion of the flammables and propagation of flame through the flammable cloud can be viewed on the CSB website, www.csb.gov.

H.1 Surveys of Blast Damage

An extensive survey was made of the damage caused by the blast. The survey included qualitative recording of damage with photographs, field notes, and detailed measurements of permanent deformations. The purpose of this survey was to provide data that could be used to estimate the severity of the explosion in terms of observed overpressure. An important part of this survey included documentation of trailers and other portable buildings damaged by the blast. A total of 50 trailers and other portable buildings were examined and information regarding structural damage and internal hazards recorded. The survey also contained a detailed examination of structural damage to permanent buildings located near the ISOM unit, including the catalyst warehouse, ISOM satellite control room, the electrical switchgear building near the blowdown drum and stack, and various buildings in surrounding process units.

A separate survey was conducted on the damaged storage tanks in the refinery tank farm south of the ISOM unit, and off-site window breakage to residential homes and commercial buildings surrounding the plant. As over 50 tanks sustained varying degrees of structural damage from the explosion, the storage tank survey was undertaken to understand the nature and extent of blast loads on these structures. Specific analysis was conducted on a severely damaged tank to estimate the observed overpressure. Inspections were also performed on over 20 selected properties. The off-site survey was not intended to be a thorough investigation to identify every structure with broken window glass, but a qualitative study to identify the type of damage off-site and range of discernable damage.

H.2 Blast Damage Analysis

Both dispersion modeling and the blast modeling used computational fluid dynamics (CFD) to investigate flammable cloud formation and to generate blast overpressure contours. Structural analysis of the blast damage measured in the field survey to objects and buildings provided an estimate of the blast load experienced by these objects, or “indicators.” Some indicators used in this analysis were deformed and/or damaged steel plates and lids, electrical box covers, and elevated switchgear buildings. Other indicators included permanent unit structures, such as control rooms, maintenance buildings, and pump houses. The overpressures noted in the following discussion are applied pressures, and care must be taken in correlating them to published literature values, as some of the damage indicators may have been subjected to reflected blast pressure loads, while others may be the result of side-on blast pressure loads. Even undamaged structural elements provided clues regarding the blast loading exposure as the strength if an object was greater than the applied blast load then an upper bound could be assigned.

H.3 Intense Blast Regions

The site survey identified several clear and distinct intense blast regions. These regions were characterized by locally intense structural damage and each had a surrounding pattern of directional indicators that pointed away from these areas, indicating that they were sub-explosion centers. At least two of these areas were identified in the ISOM unit: the Penex reactors and nearby heat exchangers, and the hydrogen compressor and surrounding areas (Figure H-1). Structural indicators showed that blast overpressures of 10+ psi and 5+ psi occurred at the hydrogen compressor and Penex reactor areas, respectively (Figure H-2).

The third intense blast region was the trailer area, where structural indicators showed that a blast overpressure of 2.8 psi at the double-wide and QA/QC trailers.

Additional points of interest on the blast overpressure maps (Figure H-2) are

- Areas surrounding the intense pressure regions in the ISOM unit, including the satellite control building, experienced 5 psi and greater overpressures.
- The catalyst warehouse and the six temporary trailers sited directly north of it experienced approximately 2 to 2.5 psi overpressure.
- The east edge of the NDU, first layer of storage tanks south of Ave. G, and the south edge of the ULC unit experienced about 1 psi overpressure.
- The west edge of the NDU, second layer of tanks south of Ave. G, the south portions of ULC and ARU units, and the western edge of the ARU unit experienced 0.5 psi and greater overpressures.
- Five ULC turnaround trailers sited west of Sixth Street; the remainder of ULC and ARU units, and storage tanks farther south experienced 0.25 psi and greater overpressures.

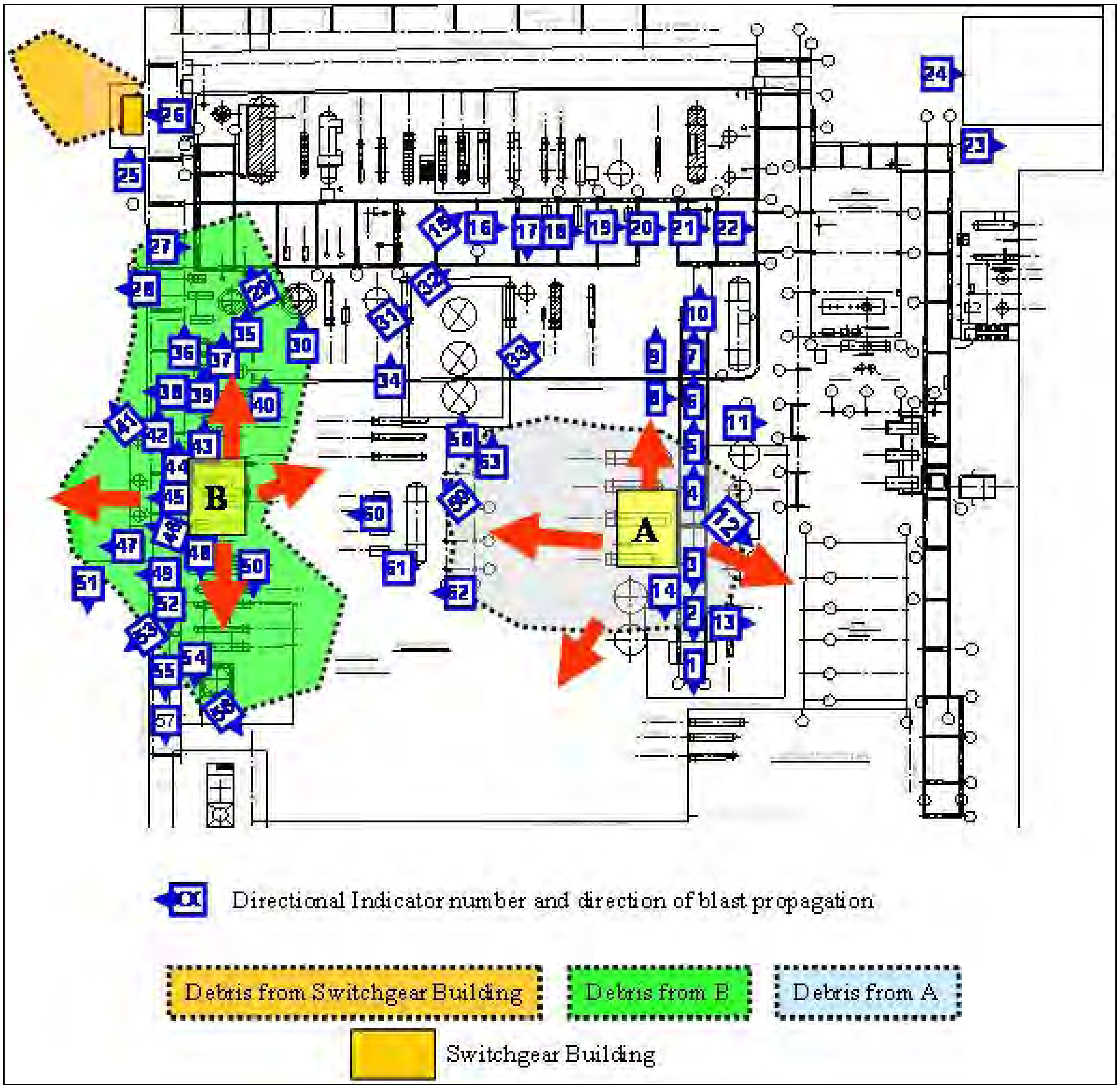

Figure H- 1. Intense blast regions in the ISOM unit

The blast overpressures presented on the map are free-field values and do not address blast wave reflections. Objects facing the blast can experience applied blast wave pressure higher than the free-field values.

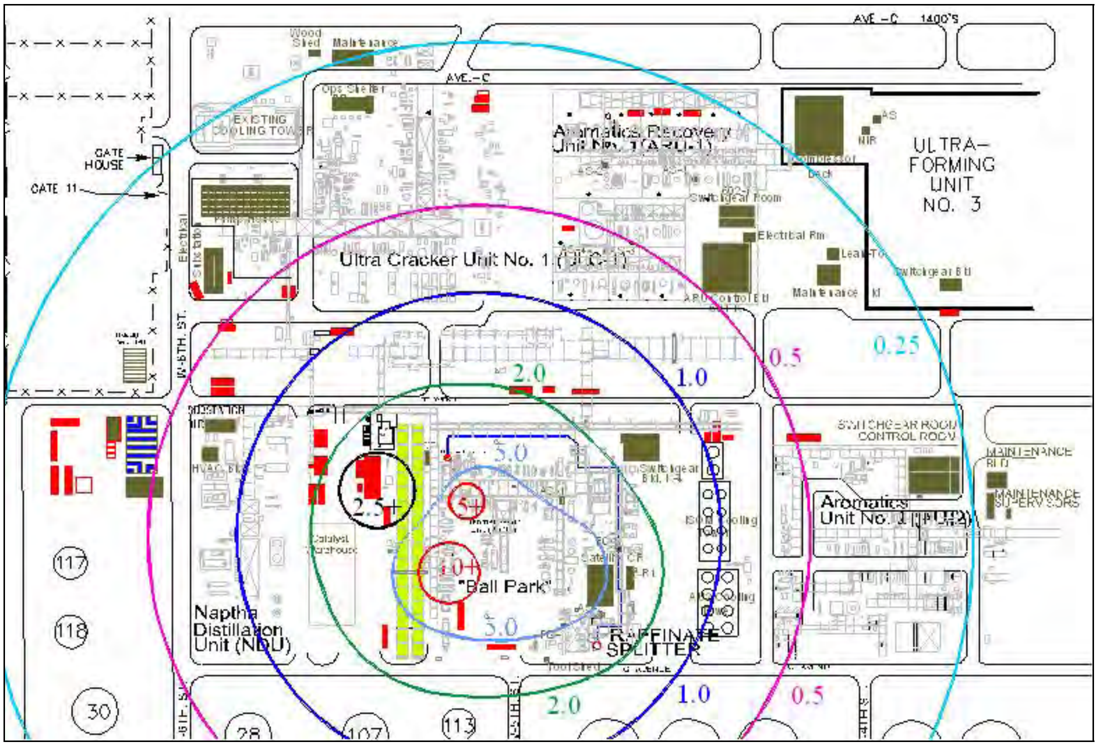

Figure H- 2. Blast overpressure map

H.4 Trailer Damage

Trailer damage varied with distance from the ISOM unit. Distances reported in this discussion are measured from the blowdown drum to the centers of the trailers. This is not to imply that blowdown drum was the epicenter of the explosion event, but it was the point of release and serves as a convenient, fixed point of reference. Table H-1 summarizes damage to the various types of trailers at the BP Texas City refinery.

Table H- 1. Trailer damage

Type of Trailer	Distance from Blowdown Drum (feet)	Summary of Damage
Wood Framed	140 to 240	Trailers and contents destroyed; debris thrown; occupants killed or seriously injured
	240 to 620	Significant wall damage, some structural failure; flying window glass; internal debris hazards
	620 and beyond	Broken window glass, internal debris hazards
Semi-Trailers and 5th Wheel Trailers (metal construction)	220 – 250	Wall and roof failures; significant internal debris hazards
	250 – 270	Deformation of walls and roof, but not to failure; internal debris hazards
	455 and beyond	Broken window glass
Steel Container Units	340	Large deformation of walls and roof; contents significantly dislodged presenting internal debris hazards
	450 and beyond	No apparent damage

H.5 ISOM Satellite Control Room Building

The building windows failed and one door was blown into the building. The masonry block walls experienced widespread heavy damage, especially the west wall that faced the ISOM. Inside, fallen cabinets and light fixtures, objects thrown from the walls, and flying glass hazards were observed. The structural analysis estimated that the ISOM satellite control room experienced a side-on blast overpressure in the range of 1.5 to 2.5 psi.

The wall facing the blast experienced blowout of the external face of the masonry block at or near midspan. One explanation of this damage pattern is that the wall experienced compression arching and the building had inherent structural features that would facilitate this possibility. Masonry walls that respond with compression arching exhibit higher out-of-plane capacity than walls that do not develop arching action. Therefore, the arching action in the Satellite Control Building may have reduced the level of wall damage from that which would have otherwise been observed. Conclusions regarding the strength of masonry walls drawn from the observed damage to the Satellite Control Building should consider the potential that arching occurred.

H.6 Catalyst Warehouse

The catalyst warehouse was essentially destroyed by the explosion. Analysis determined that the damage was constant with external overpressure and there was no evidence of an internal explosion. Structural analysis estimated that this conventional pre-engineered steel building was subjected to a side-on blast overpressure of about 2.0 psi.

H.7 Storage Tanks

The structural damage sustained by the storage tanks can be broadly classified into three types: (a) minor buckling and creasing, mostly localized in the top two or three courses of the shell wall, which was observed primarily for tanks with floating roofs; (b) minor damage to the cone roof and buckling on the upper courses of the shell wall, observed in a large number of tanks having a fixed roof; (c) major damage to one or both the roof and the shell wall. Large buckling of a portion or portions of the shell wall was usually associated with this kind of damage. In general, the row of tanks immediately south of the ISOM unit sustained damaged of type (c); side-on blast loads on some of these tanks would have been in excess of 1.0 psi overpressure.

The remaining tanks were damage classes (a) or (b), depending on the roof configuration. The tanks situated to the west and northeast of the unit had relatively minor damage (b). One possible reason for this disparity in damage could be the shielding effect of the blast provided by the process units in the west and northwest directions, and the lack of units to the south. The effect of the blast was evident in some tanks situated 2,000 feet (610 m) south of the incident; however, the damage was minor and can be classified as type (b).

H.8 Off-Site Buildings

The pattern of off-site window breakage at Texas City was consistent with relatively low overpressures (on the order of 0.1 psi or less) expected at the distances observed and for the types and sizes of windows inspected. The farthest identified glass damage was approximately 2,000 feet (610 m) from the refinery perimeter, or three-quarters of a mile from the blowdown drum and stack. Residential homes received more damage and were affected at greater distances from the refinery than commercial properties. This is a result of weaker construction of residential windows compared to commercial windows. Damage reached farthest to the north and west sides of the plant, as the ISOM unit was located in the northwest portion of the refinery and the predominance of homes and off-site commercial buildings are located in that direction from the plant.

H.9 Vapor Cloud Dispersion Modeling

Analysis and computer models were used to recreate the formation of the flammable cloud. This allowed key parameters to be examined, such as the likely mechanism(s) for the generation of the flammable vapors and the effects of wind and time on the dispersion of the flammable vapors. The results of the dispersion modeling revealed several sources of vapor production, including evaporation of liquid droplets during their fall from the blowdown stack, evaporation of liquid droplets after impact with elevated equipment and during fall to the ground, evaporation of the ground pool, and evaporation off elevated equipment wetted by the liquid. A vapor production rate as high as 100 kg/sec can be justified when all the above sources are considered, but a rate of 60 kg/sec compared best with field observations.

H.10 Methodology

Dispersion modeling used the FLACS (FLame ACceleration Simulator) Computational Fluid Dynamics (CFD) code.[252] The FLACS code used source term inputs developed using the Process Hazards Analysis Software Tool (PHAST.)[253] A 3D geometric model of the ISOM unit and surrounding structures was first constructed in CAD (computer-aided drafting) based on measurements made during the site investigations and supplemented with plan drawings of the units. The CAD model included a majority of the buildings, larger pieces of equipment, piping, vehicles, buildings, tanks, berms, pipe runs, and other objects in and around the ISOM unit. Rather than attempt to recreate each item individually, locations with significant amounts of small diameter objects (tubing, cabling, piping, etc.) were represented in the model by 3D arrays of objects with the approximate size and spacing of the objects observed in the field.

Large items (e.g., buildings and units) in the upwind direction were included, or approximated as solid blocks, as these items could influence development of wind patterns. The CAD model was then imported into FLACS. The numerical model was then established by meshing the CAD model into a non-uniform hexahedral grid of cells with a fine region in the vicinity of the ISOM unit, and stretched cells near the boundaries. Each cell in the model contains the values of the primary flow variables (such as pressure, temperature, and density) and flow equations are used to solve transfers between cells for each unit time step.

H.10.1 Wind Effects

Wind effects were included in the FLACS modeling. A steady-state wind profile throughout the model domain was established prior to initiating dispersion of the flammable material source. The initial wind speed specified in the model was an average value based on BP plant measurements taken at the North

[252] FLACS is commercially available through GexCon, a company in the CMR group; its principal offices are in Norway.

[253] PHAST software is commercially available from DNV.

Office Building weather station at or about the time of the actual explosion. As the model ran, the initial wind speed changed over the domain as the wind interacted with objects; once a steady-state was achieved, dispersion modeling of the flammable material was initiated.

The wind modeling allowed formation of local variation in wind patterns that resulted from the influence of obstacles in the FLACS domain. Wind speed was significantly influenced downwind of large objects or areas of congestion. A large portion of the ISOM unit was observed to be less than half of the initial wind speed and portions were near zero wind speed. Similar reductions were seen immediately downwind of the catalyst warehouse, the trailer area, and other buildings in the area.

H.10.2 Source Term

Table H-2 shows data used for the release rate of liquid hydrocarbons from the blowdown stack. The release was determined to be liquid at the release temperature, so any vapor formation would occur as that liquid interacted with the environment. The PHAST model was used to determine the rate of production of flammable vapor due to interaction with the environment, as FLACS lacks the ability to determine the rate of vapor production from a liquid release. FLACS was then used to determine the dispersion of a gaseous source into the complex 3D domain.

Table H- 2. Source term release and material property data

Release Information	
Release Duration (start till ignition)	106 seconds
Average Flow Rate	177 kg/sec
Total Quantity Released	18,800 kg
Release Temperature	317 to 320 K
Release Mixture Components (Weight Fraction)	
n-pentane	0.0383
i-pentane	0.0263
n-hexane	0.1519
i-hexane	0.2950
n-heptane	0.3072
n-octane	0.1300
n-nonane	0.0409
n-decane	0.0104
Mixture Properties (317 K, 1 atm)	
Average Molecular Weight	93.7 kg/k-mol
Physical State	Liquid
Boiling Point	347 K
Liquid Density	642.8 kg/m^3

H.11 PHAST Modeling

PHAST Version 6.5 was used to determine the fraction of liquid release that evaporates during the fall and the fraction that "rains out" reaching the ground to pool. The input parameters used in the model are listed in Table H-3.

Table H- 3. PHAST input parameters

Fluid	Mixture (using weight fractions from Table G.1)
Model	Line Rupture Model
Temperature	317 K
Pressure	200 Pa
Pipe Length	23.3 m (stack length)
Internal diameter	0.8255 m
Release Elevation	35 m (top of blowdown stack)
Atmospheric Conditions	80°F 70 percent relative humidity 5 mph wind Class A stability

The results from the PHAST modeling are shown in Table H-4.

Table H- 4. PHAST model results

Mean Droplet Size	0.919 mm
Maximum Droplet Horizontal Trajectory	Approximately 6.5 m (21 ft.)
Liquid Rainout Fraction	0.55
Droplet Evaporation Rate	78.3 kg/sec
Pool Characteristics	Radius 13 m at 68 seconds, evaporation rate 1.6 kg/sec Radius 24 m at 90 seconds, evaporation rate 5 kg/sec Radius 27 m at 106 second, evaporation rate 6.8 kg/sec

The droplet evaporation rate of just over 78 kg/sec is significant, as it indicates significant vapor formation during free-fall of the droplets. Another mechanical breakup mechanism is the impact of the falling liquid on elevated equipment below the blowdown drum (pipe racks, vessels, grating, decks, and ladders). A survey was used to determine the ratio of horizontal area of elevated equipment to the area of the ground as a function of radius away from the blowdown drum. Near the stack of the blowdown drum, the ratio is 100 percent due to the configuration of blowdown drum itself; otherwise it varies between 30 to 50 percent. The PHAST results indicate a horizontal drift around 20 feet (6 m); therefore, a substantial portion (approximately 30 percent) of the falling droplets would impact elevated equipment, resulting in spray. The height above the ground that liquid drops would be impacting equipment varied, but typically ranged from 15 to 30 feet (4.5 to 9 m). Liquid droplets impacting elevated equipment would produce multiple smaller drops, which in turn would increase evaporation.

H.12 Pool Evaporation

A portion of the liquid release from the blowdown stack “rained out” onto the ground and on elevated objects near the drum. As Table F-3 notes, the PHAST model included the effects of pool evaporation due to the rain-out fraction of the liquid. For a liquid release at 317 K, PHAST determined a pool temperature of approximately 285 K, which is a result of evaporative cooling and heat transfer to the droplets as they fall to the ground. This cooling effect strongly influences the eventual pool vapor contribution; thus, the contribution of evaporation from the ground pool is much smaller than that predicted for evaporation during droplet fall to the ground. Of course, additional evaporation would have occurred from elevated equipment items wetted by rainout. As elevated equipment is made of metal, and some of it also had hot process fluids or steam flowing through it, it will likely have a significantly higher heat transfer rate than the ground. Consequently, the contribution of this equipment to liquid droplet evaporation is likely to be much greater than simply the ratio of the area.

H.13 FLACS Vapor Dispersion Modeling

A large domain was chosen that exceeded the expected extent of the flammable dispersion. The domain was also large enough to address sizeable objects around the perimeter of the ISOM unit that would affect wind patterns and ultimately dispersion of flammables. Steady-state wind conditions, as described, were established prior to beginning the dispersion of flammable materials. The dispersion grid was set at 1 meter in the X, Y, and Z directions for the bulk of the model. A tighter grid was chosen at low elevations where the heavy flammable vapor cloud was expected to settle. The CFD modeling attempted to simulate the release conditions and source terms described previously. The CFD model included several vapor source terms that represent vapor generated from evaporation of falling liquid, vapor generated through evaporation when liquid interacted with elevated equipment, and vapor generated by evaporation from liquid pooled on the ground. The numerically discrete nature of CFD allows specifications of definite leak locations; therefore, vapor sources were placed in the model at various locations to represent potential sources. A total of 16 discrete “leak” locations were selected that would be vapor sources in the model, including four sets, placed at various elevations, of four leaks located about the perimeter of blowdown drum. A parameter study that varied the rate of vapor generation for the source terms was then conducted and comparisons made against field data and observations. A comparison (Figure H-3) shows reasonable agreement.

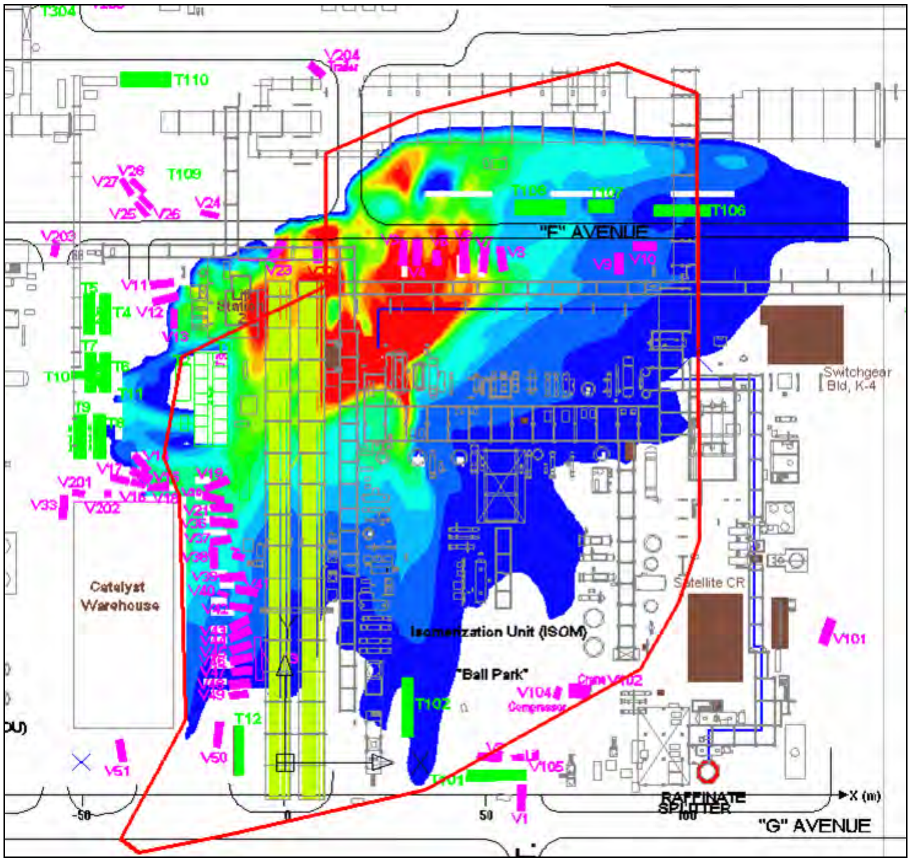

Figure H- 3. Cloud extent comparing field observations (red line) to dispersion modeling

H.13.1 Results

The FLACS dispersion modeling revealed several key items regarding the extent of the vapor cloud:

- Significant amounts of flammable vapor spread around the double-wide and QA/QC trailers. This area was not downwind of the blowdown drum and stack and, therefore, migration into this area was not intuitive. This cross-wind migration was probably the result of a) wind patterns predicted by modeling indicated a relatively quiet region between blowdown drum and the double-wide trailer where all the fatalities occurred; b) the portion of the flow attempting to move upwind (toward the northwest) is redirected, including some toward the trailers; c) the pipe run is at a lower elevation in relation to the concrete slab on which the ISOM was built, and thus gravity attracted the heavier than air flammables in that direction.

- Dispersion modeling places flammable vapors over a significant portion of the pipe run and is consistent with field observations and eyewitness statements.
- Dispersion modeling places flammable vapors around vehicles parked between the catalyst warehouse and the pipe run, which is constant with field observations and eyewitness statements.
- Dispersion modeling places flammable vapors at the south end of the ISOM unit, which is also consistent with field observations and eyewitness statements.

H.14 Explosion Modeling Methodology

FLACS was also the tool used to model the explosion of flammable vapor cloud in the ISOM unit and surrounding areas. The explosion modeling examined two scenarios: the global events involving combustion of the entire flammable cloud, and the propagation of the flame-front through the pipe run and under the double-wide trailer. Attempts were made to simulate burning of the dispersed, non-homogenous cloud taken directly from the dispersion output; however, this could not be accomplished with FLACS. Instead, the explosion analysis used a uniform stoichiometric vapor cloud covering similar areas in and around the ISOM unit using a cloud volume estimated by FLACS based on cloud size and amount of congestion in the area.

H.15 Vapor Cloud Formation

Typical dispersion models assume that a low-momentum, sub-cooled liquid release falls to the ground with minimum vaporization. The resultant ground-level pool, formed from the low volatility liquid, simultaneously spreads and vaporizes by forced or free convection evaporation and forms a flammable mixture with air. The evaporation rate depends on several factors: the area of the liquid exposed to air, the velocity of the airstream moving over the spill, the temperature and humidity of the air, and the physical properties of the spilled liquid.

Much of the ground area near the blowdown drum was covered by vertical or horizontal equipment, pipe racks with multiple pipes, concrete pads with curbs, etc., and there was only a limited, flat horizontal area in which a pool of liquid could form and spread in a concentric circle; thus, correlations used to determine the mass of the flammable vapor cloud for a fixed period due solely to evaporation from a large ground pool would not necessarily apply. Based on the wind direction at the time of the incident and eyewitness accounts, the CSB believes that substantial portions of the hydrocarbon liquid released from the stack cascaded down the stack and drum or fell onto nearby process equipment. Using a 3D CAD drawing of the blowdown drum and stack and surrounding equipment, the CSB estimates that only 40 percent of the liquid spewing from the stack would have landed directly on the ground to create a liquid pool at the base of the blowdown drum.

The CSB believes that the evaporation of the hydrocarbon liquid droplets and the formation and dispersion of the flammable vapor cloud could approach that resulting from the mechanical breakup of a high momentum sub-cooled liquid release. The liquid cascading down the drum and stack and the smashing impact of falling liquid onto process equipment, structural components, and piping promoted fragmentation into relatively small droplets, thereby enhancing the evaporation and formation of a flammable vapor cloud. The CSB notes that this effect was similar to the evaporation mechanism cited in the incident investigation analysis of a recent large gasoline spill in the United Kingdom (HSE 2006a, 2006b). Some contribution would also be made to the flammable vapor cloud due to forced convection evaporation from the expanding ground-level liquid pool. Evaporation of liquid from wetted process equipment, structural supports, and the surfaces of pipes--especially if they were above ambient conditions--also likely contributed to the formation of the flammable vapor cloud. The atmospheric wind then pushed the vapors and small droplets downwind, causing them to mix with air. The wind direction at the time of the incident was reported to be out of the northwest traveling southeast and the burned area is elongated in that direction.

The second dispersion mechanism results from the expansion of the flammable vapor cloud ahead of an approaching subsonic frame-front. Such a flame-front pushes vapors ahead of it, like a piston, and causes the flammable vapor cloud to expand from its pre-ignition size and the flammable vapors to mix with air. If congestion (process vessels, pipes, structural supports) is present in areas ahead of the flame-front, turbulence is generated as vapors move through this congestion, which promotes mixing of the vapor with air; consequently, the flame-front will burn faster once it reaches this area and generate greater pressure. The CSB, which estimated that the size of the vapor cloud expanded about 12-15 percent, developed a computer simulation of the dispersion and expansion of the vapor cloud, which can be viewed or downloaded from the agency’s website. www.csb.gov.

H.16 Ignition Locations

Four ignition locations were examined:

1. A diesel truck located at north end of the ISOM. Eyewitnesses reported that this truck, which was idling, began over-revving and ignited the vapor cloud.

2. A switchgear building near the blowdown drum in the northwest corner of the ISOM unit.

3. An operating furnace at the southwest corner of the ISOM.

4. A diesel truck parked immediately north of a contractor trailer in the south end of the ISOM unit. This vehicle was found to have the ignition key in the “on” position, the hood panel blown off, and the air intake disrupted.

All ignition locations were relatively in the open. The model runs showed that the initial burn rate was relatively slow for all ignition locations due to lack of congestion near the ignition points, and that the flame-front accelerated upon encountering congestion. The two south-end ignition scenarios (3 and 4) were eliminated, as the blast modeling did not predict the overpressure patterns, known to have occurred based on the structural analysis, in the south region of the ISOM. Some of the highest overpressures recorded were observed at the hydrogen compressor station; model runs indicate that ignitions at points 3 and 4 would be unable to generate adequate overpressure in this region to explain the observed damages. An ignition at locations 1 or 2, and at the north end of the ISOM unit, resulted in blast patterns consistent with observed structural damage.

A close examination of ignition location 2, the switchgear building, showed that it did not display significant evidence of an interior explosion, as any internal ignition of flammable vapors that had entered the building would have resulted in pressure buildup inside until wall and roof panels released and were thrown outward in all directions. Only some of the damage to the switchgear building is consistent with an internal explosion; however, all the damage is consistent with a blast wave, principally from the southwest, reaching the building. The south wall was destroyed and pushed inward and the southernmost cabinets were heavily damaged on the south face of the building. The north wall was pushed outward. The east wall was intact and found leaning inward against the east row of electrical cabinets. The west wall was destroyed and the bulk of the wall panels were thrown into the pipe rack running north to south, between the ISOM unit and the trailer area. The roof was destroyed and the bulk of the roof panels were recovered in the Pipe Run to the northwest. The observed damage pattern was not uniform, but was in fact directional. Additional structural deformation patterns were identified that indicated that the damage to this building was from a blast generated to the southwest and in the ISOM unit. Thus scenario 2 is eliminated as an ignition point. Therefore, scenario 1 remains the likely candidate and is consistent with all observed structural damage; however, the modeling alone cannot confirm this as the ignition point.

H.17 Additional Explosion Modeling

By performing additional explosion modeling using FLACS, the CSB was able to closely look at the propagation of the flame front through the pipe run and around and under the double-wide trailer. The additional modeling investigated the impacts of the pipe run and trailer on local flame speed and associated blast pressures. To do this detailed modeling, the region around the pipe run and double-wide trailer were specifically modeled with a smaller mesh than that used in the large domain model. Ignition of the flammable vapor was initiated to the east of the pipe to simulate a flame exiting the west edge of the ISOM unit.

H.17.1 Results

Modeling indicates that the explosion event (from initiation to blast-generating flame-front passing through the entire flammable cloud) lasted about four seconds. After the vapor cloud had ignited, a relatively slow flame spread in an uncongested area. Upon reaching a more congested area north of the ISOM unit, flame-front speed increased and varied in intensity as the flame moved in and out of congested and/or confined areas. After the explosion, a large rising fireball persisted, burning fuel uninvolved in the initial explosion.

The explosion pressures from the blast modeling are generally consistent with values calculated by structural analysis of damaged indicators. The highest pressures recorded were in localized areas of the ISOM unit with high levels of congestion. The most predominate was the hydrogen compressor deck, where 10 or over psi was likely experienced. Blast modeling generally indicated that the bulk of the ISOM unit experienced overpressures in the range of 2.0 to 5.0 psi. Pressures as high as 2.0 psi were experienced at the catalyst warehouse, six-pack trailer area, and Avenues F and G. A 1.0 psi pressure extended into the NDU and to the first layer of storage tanks south of Avenue G to the south edge of ULC. The west edge of the NDU second layer of tanks south of Avenue G, south portions of the UCU-1 and ARU-1, and western edge of ARU-2 reached 0.5 psi (Figure H-2).

The pipe run influenced flame movement across the region between the ISOM and trailer area, and prevented any significant reduction in flame speed, as would have occurred in an open field. Further, the congestion and confinement of the trailers, nearby vehicles, and nearby equipment likely supported locally high flame speed and corresponding high overpressures (approximately 2.5+ psi). Hence, the physical separation between the trailer area and the ISOM unit did not reduce the blast pressures, as would be the case in an open field.

APPENDIX I: Historical data on 19 raffinate unit startups

	Date of Start-up	Time feed was sent from ARU to Raff tower	Highest level transmitter reading (Percentage) / Time Over Range From When Feed to Unit Started and Circulated	Was level over range at the time feed to unit started?	Number of times level went above the range of transmitter during start up	Number of times level was in alarm during start-up	Duration [hrs, min] the level was in alarm	Maximum swing in tower level during start-up	Duration heavy raff to storage before/ after start of feed and time	Was level control valve in auto at time when heavy raff sent to storage?/ Duration in auto?	Was level control valve in auto prior to start of gas to heater?/ Duration in auto?	Number of times tower level swings or heavy raff flow shut off/ Was level set point other than 50%	Startup in manual or auto the majority of the time?
1	3/23/05	2:19 am	98%/None	No	0	1 high 1 low	09:54 high 00:16 low	95%	3 Hours 8 min after	No/Never put in auto	No/ Never put in auto	1/Yes	Manual
2	9/06/04	1:38 pm	95%/None	No	0	5 high 1 low	00:58 high 00:18 low	90%	25 min after	No/46 min	No/1 Hour 3 min	5/Yes	Manual
3	1/17/04	2:04 pm	92%/None	No	0	2 high	04:32 high	45%	26 min after	No/1 Hour 4 min	No/1 Hour 3 min	1/Yes	Manual
4	10/29/03	4:02 pm	92%/None	No	0	2 high 1 low	04:21 high 00:06 low	75%	12 min after	No/2 Hour 27 min	No/2 Hour 26 min	3/Yes	Manual
5	6/16/03	10:25 pm	Over Range/ 18 min	Yes	1	4 high 1 low	01:00 high 00:03 low	>60%	11 min before	No/31 min	No/1 Hour 23 min	4/Yes	Auto
6	2/22/03	5:08 pm	Over Range/ 23 min.	No	2	5 high 2 low	02:57 high 04:22 low	>80%	52 min after	No/8 hour 25 min	No 8 hour 29 min	6/Yes	Manual
7	10/3/02	4:13 am	Over Range/ 2 hours 40 min.	Yes	2	2 high 1 low	02:18 high 00:11 low	>85%	56 min after	No/1 hour 23 min	No/2 Hour 25 min	3/Yes	Manual
8	7/27/02	3:56 pm	Over Range/ 36 min.	Yes	2	2 high 1 low	00:58 high 00:01 low	>65%	8 min after	No/1 hour 13 min	No/1 Hour 7 min	5/Yes	Manual
9	6/19/02	5:23 am	Over Range/ 37 min.	Yes	1	4 high	00:48 high	>55%	7 min after	No/1 Hr 41 min	No/1 Hour 38 min	5/Yes	Manual
10	6/17/02	8:54 pm	Over Range/ 1 hour 17 min.	Yes	1	2 high	01:34 high	10%	1 Hr 16 min after	No/No sign it was set to auto	No/ No sign it was set to auto	2/ No sign it was set to auto	Manual
11	2/07/02	11:00 am	Over Range/ 1 hour 22 min.	Yes	2	4 high	04:31 high	25%	53 min after	No/7 hr. 22 min	No/5 hr 58 min	12/Yes	
12	7/21/01	12:55 pm	Over Range/ 5 min.	No	1	5 high	01:47 high	>85%	15 min. after	No/39 min	No/26 min	1/Yes	Manual
13	2/24/01	9:41 am	Over Range / 9 min	No	1	2 high	00:26 high	>85%	5 min after	No/26 min	No/29 min	1/Yes	Manual
14	2/8/01	12:37 pm	Over Range/6 min	No	1	5 high	00:39 high	>60%	9 min after	No/20 min	No/36 min	3/Yes	Manual
15	2/02/01	3:17 pm	Over Range/ 4 hours 27 min.	No	1	3 high	04:58 high	>50%	10 min. after	No/3 hr. 40 min	No/3 hr. 46 min.	1/Yes	Manual
16	11/02/00	10:28 am	Over Range/ 1 Hour 48 min.	No	1	4 high	02:45 high	>60%	14 min. after	No/ 4 min.	Yes	2/Yes	Auto
17	9/02/00	12:36 am	Over Range/ 1 Hour 8 min.	No	1	4 high	01:44 high	>60%	15 min. after	No/1 hr. 34 min.	No/1 hr 28 min.	3/Yes	Manual
18	5/10/00	8:51 am	Over Range/ 1 Hour 45 min	Yes	3	6 high	02:19 high	>60%	26 min. after	No/ 1 hr. 9 min.	No/ 1 hr. 16 min.	5/Yes	Manual
19	4/12/00	7:50 pm	Over Range/ 1 Hour 14 min.	Yes	2	3 high 1 low	01:37 high 00:03 low	>67%	2 min. before	No/ 4 min.	No/ 3 min.	1/Yes	Manual/ Auto initially

APPENDIX J: Ineffective and Insufficient Communication

J.1 What is Effective Communication?

Basic communication consists of a sender (the one with the information); the message (the information itself); the receiver (the one who obtains and processes the information); and the method(s) used to communicate the message.

Research shows that verbal communication is most effective for creating a shared understanding of information because it allows for two-way transference of data. Face-to-face communication affords the receiver the opportunity to reiterate the information, ask questions, and have ambiguous data clarified. It also allows the sender to confirm that the information was transmitted correctly and to resubmit the message if necessary. Written communication may be less effective because it lacks this immediate feedback. However, because repeating information increases the likelihood of comprehension, multiple methods of communication are essential in ensuring that accurate, unambiguous data has been transferred.

Feedback is associated with more accurate information sharing, but is more time-intensive than other methods of communication; that is, it takes more time to verbally share information and allow for feedback from both parties than it does to pass a message through other channels, such as written. But written messages are especially necessary for critical unit operations, where the information communicated could play a significant role in preventing or causing a catastrophic incident.

CCPS (2004) produced a safety alert on ways to improve process safety through effective communication. Additionally, the U.K. Health and Safety Executive published a literature review of effective shift turnover (Lardner, 1996). Both documents conclude that communication is most effective when it includes multiple methods of communication (both verbal and written); allows for feedback; and is emphasized by the company as integral to the safe running of the units (Lardner, 1996; CCPS, 2004).

BP's Grangemouth refinery in the United Kingdom came to the same conclusion after examining shift communication at its facility in the early 1990s.

J.2 BP Grangemouth Refinery Study on Effective Communication

The Grangemouth refinery studied safe communication at shift handover, which was presented at an ICHEME conference in 1995 (Adamson, 1995). The data collected resulted in a site-wide initiative to modify and enhance shift turnover activities to encourage more effective communication, particularly during times of abnormal plant conditions where risk of a miscommunication leading to a incident are far greater than during time of normal operation. The study looked to answer the question: "What verbal and written information should be included [during a shift turnover,] and how should this be communicated effectively?" (Adamson, 1995).

This study revealed that while operators communicated both verbally and via logbooks, the type of information being shared was not always complete and efficient. Logbooks were unstructured (lined notebooks) and operators did not receive guidance on the type of information that should be passed. (These conditions paralleled those of the BP Texas City refinery, particularly for the ISOM unit.) Operators used different styles and formats; some wrote a lot, others hardly at all. The logbooks were mostly historical records and little information was collected on what should be done in the future. No data on safety issues with the unit were written in the logbooks. While shift handover was discussed during new operator training, because no structured guidance was given, BP was unable to adequately judge trainees' ability to effectively communicate between shifts.

From this data, BP developed training that emphasized the importance of both the sender and receiver in effective communication and that increased operators' perceived responsibility in the two-way transmission of information between shifts. Structured logbooks – created with the help of the actual operators – were implemented. These new logbooks contained required categories of information, including safety, maintenance and technical problems, work outstanding, comments/remarks, and signatures of logbook authors. The study found that these new logbooks resulted in several improvements in written communication: “More information on maintenance and technical problems was being recorded, safety issues were being flagged up and timings of events were being recorded more consistently. Furthermore, the information contained in the logs was easier to access and read” (Adamson, 1995). The structured logs also acted as a memory aid and helped operators know what information was important to communicate to oncoming staff.

J.3 Summary

In complex and critical process systems, multi-channel communication with feedback provides the best opportunity for operators to establish and maintain a mutual understanding of the process unit and its expected future state. During times of abnormal operating conditions, such as unit startup, the risk of operators having dissimilar or incompatible understandings of the state of the process unit is even greater, making effective communication vital and feedback essential (Lardner, 1996).

APPENDIX K: Design of the AU2/ISOM/NDU Control Board

The control board for the ISOM/NDU/AU2 complex (Figure K-1) consisted of eight computerized control board monitor screens, four of which could be subdivided into four smaller display windows, for a total of 20 screen windows. Additionally, four additional monitors (two on either side of the eight monitor screens) displayed the critical unit alarms.

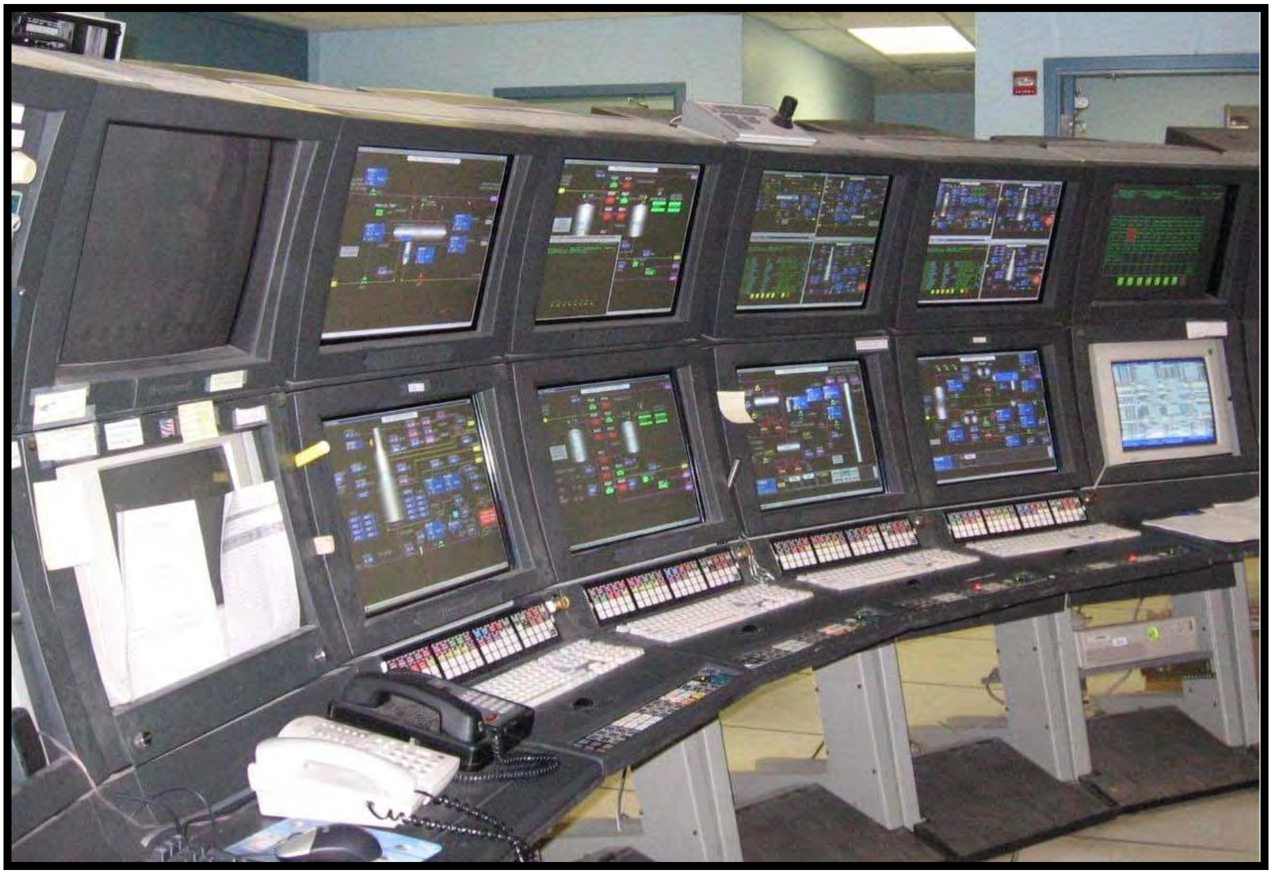

Figure K- 1 The computerized control system for the AU2/ISOM/NDU complex

Three of the smaller screen windows were reserved strictly for alarm data (one for each unit). Each was a historical (chronological) record of the alarms; the alarm data displayed on these three screens could also be sorted by alarm priority type (low, high, emergency/critical). Additionally, the board operator was responsible for monitoring four more screens that provided critical alarm data (see numbered screens in Figure K-1). One alarm enunciator screen was specifically for the ISOM unit, one was for the NDU, and the two remaining were for the AU2 unit. Each alarm screen displayed a matrix of the critical alarms for its designated unit. If a critical alarm sounded, the color of the alarm changed and blinked to visually warn the board operator. All screens were operational at the time of the March 23, 2005, incident. Besides the three-quarter screen windows containing alarm information, what was actually viewed on each of the remaining 16 computerized control board monitor screens varied based on board operator's judgment. Each unit had several screen pages that depicted schematics of different portions of the unit, as well as an "Overall" screen page that would generally depict the whole unit system, but would lack the detail the other screen pages provided. The raffinate section, for example, had several screen pages that could be brought up to monitor different sections or equipment of the process unit. These screen pages were originally developed by the computerized control system provider and then modified based on engineering and operations personnel input.

APPENDIX L: Staffing Concerns

Texas City refinery operations personnel raised staffing concerns. A 1996 staffing assessment performed for all Texas City refinery process units used specific guidelines designed to evaluate minimum staffing level requirements during normal (routine) and safe-off operations, and to determine the level of training necessary to develop and maintain a knowledgeable workforce. A general observation from the assessment was that operations personnel would be unable to safely handle unit upsets with the current staffing arrangements.[254] But this concern was not addressed any further in the staffing assessment.

The Steelworkers Union also contended that there was unsafe staffing. In a November 2000 Process Safety Committee meeting, the Union presented BP with written documentation expressing employee concern over operator staffing.

> Through the Joint Health and Safety Committee, PACE Union 4-449 is notifying the company, BP, of its concern on the issue of the complement of operators relative to providing adequate staffing levels to assure safe and environmentally sound operations at the Texas City Refinery site. Issues include operator staffing levels below the numbers required for 'safe off staffing'. This involves the day to day operation of units with less than the minimum numbers of operators required. The situations worsen when staffing of extra board decreases to the extent of operators working excessive amounts of overtime, which adds worker fatigue into potential job performance problems.[255]

The PSM group was to follow up on the staffing concern, but the grievance was not resolved. This concern for staffing reductions came on the heels of an October 9, 2000, BP "Texas City Safety Talk" newsletter (disseminated to operations personnel) that reported on a hydrocarbon release incident at BP's

[254] Amoco 1996 Staffing Assessment

[255] This grievance was reviewed in BP Texas City Process Safety Committee meeting minutes, November 21, 2000.

Lavera Refinery. One of the lessons learned from the incident was that "[s]ufficient qualified staff with diagnostic skills must be available at unit start-ups."[256]

[256] BP – Texas City Site Safety Talk, dated October 9, 2000.

APPENDIX M: Fatigue and Performance

In section 3.7, the CSB demonstrated that fatigue likely contributed to the Board Operator's impaired ability to deduce that the tower was being filled for three hours without any liquid being removed to storage.

The Day Board Operator was experiencing an acute sleep loss of approximately 1.5 hours per 24-hour period for 29 straight days–a sleep debt of 43.5 hours. Performance can be impaired and levels of alertness decline with only two hours of sleep loss (Price, 2005; Rosekind et al., 1993). Studies show that feelings of sleepiness increased among subjects and led to a decrease in performance on vigilance (monitoring) tasks when they had five hours of sleep for seven consecutive nights (Price, 2005; Rosekind et al., 1993). This is significant when considering that the Board Operator was maintaining the 5.5-hour-per-night schedule for 29 consecutive days. Additional research comparing the effects of fatigue to alcohol inebriation finds that two hours of sleep loss produces the same performance detriments as consuming two to three beers and a blood alcohol content of .045 percent (Roehrs et al., 2003). And as sleep debt accumulates, performance becomes increasingly worse [257]: evidence that strongly suggests that a 1.5-hour sleep loss for about a month would impair the mental performance of the Day Board Operator.

M.1 Research on the Performance Effects of the 12-Hour Shift

Often in industries that run on continuous schedules, the tendency is to staff a 24-hour period with two 12-hour shifts, which much of the workforce likes (as opposed to 8 or 10 hour shifts), as they receive more time off from work and reduce time spent commuting. However, the 12-hour shift negatively affects employee performance and subjective fatigue (Rogers et al., 1999). In a study on multiple task performance (such as is the case when operating a control room), the U.K. Health and Safety Executive

[257] "Analyzing for Fatigue in Road Accidents," BP document developed by P. Gander.

[258] found that performance deteriorated throughout a 12-hour shift, even when operators were given 15-minute breaks every 75 minutes (Rogers et al., 1999). Other studies show that "exceeding the 8-hr workday can lead to lower productivity, higher accident rates, and higher absenteeism…. Fatigued workers are more likely to experience 'tunnel vision.' They are able to focus only on a few instruments rather than a whole display panel. A tired worker tends to perform very much like an unskilled worker."[259] In addition, too many consecutive workdays can lead to accumulated fatigue and increase the risk of fatigue-related problems including ill health, errors, and accidents (HSE, 2006b). And frequent overtime has been shown to increase likelihood of an accident at work, which has been demonstrated in both the coal mining and nuclear power industries (Rogers, 1999).

The cumulative sleep effects the Board Operator was experiencing may have also been compounded by the starting hour of his shift. The Health and Safety Executive published its results from a questionnaire study on fatigue in a variety of industry settings, including nuclear processing and off-shore installations. The Health and Safety Executive found that subjective levels of fatigue increased with consecutive early shifts (those starting around 6:00 a.m.). The third day of working an early morning shift resulted in a 30 percent increase in fatigue, while the fifth consecutive day of working early morning shifts resulted in a 60 percent increase in fatigue, and the seventh consecutive day resulted in a 75 percent increase compared to the first day. Individuals also reported that they needed one day off to recover from three consecutive early-morning shifts and two days off to recover from five consecutive early shifts.[260] For 29 days straight, the Day Board Operator's shift began at 6 a.m.

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258 The Health and Safety Executive is Great Britain's enforcement authority (in conjunction with local governments) for the Health and Safety Commission, a governing body responsible for regulating health and safety in the workplace.

259 Labor Occupational Health Program, U. of CA, Berkeley, "Human Factors Curriculum for Refinery Workers."

260 Ibid.

M.2 BP's Fatigue Policy

Despite not having an operator fatigue-prevention program, BP Group does have a method to analyze fatigue in road accidents involving its truck drivers.[261] BP Group documentation on vehicular fatigue incident investigations, which references NASA's and NTSB's methodology, states that when multiple fatigue factors are present, a strong argument can be made that fatigue contributed to the incident.[262] The CSB agrees and believes that the Day Board Operator–and likely the entire operations crew working the turnaround schedule–was significantly fatigued on March 23, 2005. Using NASA and NTSB methodology, the CSB concludes that fatigue of the operations personnel contributed to overfilling the tower.

Opportunities for additional overtime can be driven by economic incentives, required by work rules or encouraged; however, it is common for individuals not to realize how fatigued they actually are. Therefore, management must recognize and establish a shift work policy to minimize the effects of fatigue, and ensure that board operators who must constantly monitor hazardous installations or process units take brief, periodic breaks away from their workstation.

[261] BP document, Analyzing for Fatigue in Road Accidents, BP document developed by P. Gander.
[262] Ibid.

APPENDIX N: Comparison of Hours-for-Service regulations

Industry/ Agency	Name of Policy / Standard	Effective Date	Applies to:	Max hrs in 30-day period (on-duty time)	Max hrs/week average	Max hrs/ week	Max hrs/24-hr work period (day shift)	Min. hrs rest/off between shifts	Max # of consecutive shifts (day shift)	Max hrs/24-hr work period (night)	Other
U.S. Nuclear Regulatory Commission	Nuclear Power Plant Staff Working Hours (IE Circular No. 80-02 and Generic Letter No. 82-12)**	6/15/1982	plant operating personnel			72	12 (Note 1)	12 (Note 2)	14 (Note 3)	16	The 16 hrs max shift length and 8 hours min rest break are only allowed in "the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance or major plant modifications, on a temporary basis." Otherwise, "the objective is to have operating personnel work a normal 8-hour day, 40-hour week while the plant is operating."
Aviation	14 CFR Part 121/135	updated in 1985	pilots	100 (flying time)		30/34		9 (if flight time <8 hr) 10 (if flight time 8-9 hr) 11 (if flight time >9 hr) (Note 4)			
Marine	46 U.S.C. 8104	updates 1990 and 1997	a licensed individual on an oceangoing or coastwise vessel of not more than 100	~360 (Note 6)		70	9 (in port) 12 (at sea)				Offices in charge of a navigational or engineering watch on board any vessel that operates beyond the boundary line shall receive a minimum of 10 hours rest in any 24 hour period. Hours of rest may be divided into no more than 2 periods, one of which must be at least 6 hours in length. Hours of rest do not need to be maintained in emergency.
Federal Motor Carrier Safety Administration	49 CFR 395 Hours of Service of Drivers	1-Oct-05	passenger-carrying commercial motor vehicle driver	~260	60/70 (Note 7)		10 (driving) 15 (on duty) (Note 8)	8 (Note 9)	Note 7		If drivers use a sleeper berth, they may split the 8-hour rest period into two periods as long as neither period is less than 2 hours.

Industry/ Agency	Name of Policy / Standard	Effective Date	Applies to:	Max hrs in 30-day period (on-duty time)	Max hrs/week average	Max hrs/ week	Max hrs/24-hr work period (day shift)	Min. hrs rest/off between shifts	Max # of consecutive shifts (day shift)	Max hrs/24-hr work period (night)	Other
Federal Motor Carrier Safety Administration	49 CFR 395 Hours of Service of Drivers	1-Oct-05	property-carrying commercial motor vehicle driver	~260	60/70 (Note 7)		11 (driving) 14 (on duty) (Note 10)	10 (Note 11)	Note 7		A driver may restart a 7/8 consecutive day period after taking 34 or morn consecutive hours off duty; On any 2 days of every 7 consecutive days, the driver may extend the 14-hour duty period to 16 hours; There is no requirement that the driver be released from duty at the end of the 14 or 16 hour duty periods. The driver may continue to perform non-driving duties, which would be counted against the 60/70 hour weekly limit
Rail	49 U.S.C. 211 Hours of Service; 49 CFR Part 228	last amended 1988	signal employees	~440			12 (Note 12)	8/10 (Note 13)			may be allowed to remain or go on duty for not more than 4 additional hours in any period of 24 consecutive hours when an emergency exists and the work of the employee is related to the emergency
EU	Road Transport Directive		drivers		48 (Note 14)	60				10 (Note 15)	45-min break after 4.5 hours of continuous or cumulative driving; 30 min break in 6-9 hr working day; 45 min break in 9+ hr workday; breaks can be divided over the workday, but each must be at least 15 min long; break must not involve doing other work
Pipeline	There are no Federal regulations for operators or controllers of pipeline systems; *However, PHMSA published an Advisory Business unit leaderletin (ADB-05-06) in August 2005 with the following*		pipeline control room operators				12 (Note 16)	*10*			
UK Dept of Trade and Industry	Working Time Regulations	Oct 1998; amended Aug 2003	non mobile workers in road, sea, inland		48 (Note 17)			11 (Note 18)		8 (Note 19)	a right to a day off each week; a right to an in-work rest break (duration not specified) if the working day is longer than 6 hours

Industry/ Agency	Name of Policy / Standard	Effective Date	Applies to:	Max hrs in 30-day period (on-duty time)	Max hrs/week average	Max hrs/ week	Max hrs/24-hr work period (day shift)	Min. hrs rest/off between shifts	Max # of consecutive shifts (day shift)	Max hrs/24-hr work period (night)	Other
UK Health and Safety Executive	Inspector's Toolkit: Human Factors in the Management of Major Accident Hazards, section 6, topic 2, Managing fatigue risks	Oct-05	operators working in industries where major accident hazards exist			avoid more than 50	12	12			
BP Group	Group Driving Standard	Jan-04	"every BP employee who operates any vehicle on BP business and to all		60	80 (Note 20)	16 (Note 21)				minimum of a continuous 24 hour break during 7-day work period; minimum of 30 min break after every 5 hours
BP Texas City during turnarounds	no policy		Operators and Supervisors	348 - 408		84	12		no limit		no limit on consecutive days worked; no rest days required
BP Texas City (normal operations)	no policy; Articles of Agreement between BP	1-Feb-02	shift workers			no max given	no max given	7.5	no limit		

NOTES:

1. 16 during abnormal times or extended periods of shutdown

2. 8 during abnormal times or extended shutdown

3. Guidance: an individual should not work more than 14 consecutive days without having 2 consecutive days off

4. These are the minimum reset periods in the 24 hours preceding the scheduled completion of the flight segment

5. Hours of service requirements vary depending on type of vessel

6. For a licensed individual on an oceangoing vessel or coastwise vessel of not more than 100 gross tons at sea

7. May not drive after 60/70 hours on duty in 7/8 consecutive days (later when motor carrier operators every day of the week).

8. "Not to exceed 10 hours of driving following 8 consecutive hours off duty

may not drive after having been on duty 15 hours following 8 consecutive hours off duty"

9. May not drive after having been on duty 15 hours following 8 consecutive hours off duty

10. Not to exceed 11 hours of driving after 10 consecutive hours off duty; may not drive beyond the 14th hour after coming on duty, following 10 consecutive hours off duty.

11. Not to exceed 11 hours of driving after 10 consecutive hours off duty

12. After being on duty for 12 consecutive hours, the employee may not go on duty until the employee has had at least 10 consecutive hours off duty

13. After being on duty for 12 consecutive hours, the employee may not go on duty until the employee has had at least 10 consecutive hours off duty; after being on duty for less than 12 hours, the employee must have at least an 8-hour rest period

14. Usually averaged over 4 months; can be averaged over 6 months

15. This may be exceeded by collective workforce agreements (i.e. by signing an opt-out or derogation from the directive)

16. Shift not to exceed 12 hours in a 24-hr period except in extraordinary or emergency situations

17. Max average a worker is required to work, though worker can choose to work more if want to

18. A right to 11 hours rest a day

19. Average

20. 120 hrs/14 days max, subject to a 80 hrs/7 days max; avg of 60 hrs/week over extended period of time

21. 10 hours total maximum driving time within a 24-hour period; apparently the remaining 6 hours can be used for non-driving tasks, such as loading/unloading/etc.

APPENDIX O: Operator Training

The hazards of unit startup were inadequately covered in operator training and did not prepare the Board Operator for the tasks he was responsible for on the day of the incident. This insufficient training was compounded by the lack of annual performance appraisals, individual skill development plans, and abnormal situation management simulator training. BP provided only basic general training to its operators.

O.1 BP Board Operator Training

BP Board Operator Training consisted of a five-week Basic Operator Training course, a two-day generic troubleshooting course, computer-based tutorials, and on-the-job training.

O.1.1 Five-Week Basic Operator Training

Basic operator training (BOT)[263] was provided to newly hired individuals and covered a wide range of general refinery operations topics and operator responsibilities. Operators went through BOT prior to 2002; the Day Board Operator working on March 23 had received this training, which consisted of a review of BP standards, guidelines, safety booklet, and computer-based training. The CSB found no evidence to suggest that the training covered material balance calculations or the hazards of high liquid level in splitter towers.

O.1.2 Two-Day Troubleshooting Course

All operators also took a two-day troubleshooting course (which the Board Operator on March 23 had completed) or graduated from a college program that covered troubleshooting. However, BP did not

[263] At the time of the incident, the five-week BOT training was no longer offered at BP Texas City; the new-hire training had been shortened to 8 days. The company's rationale for the cut in training time was the requirement to hire only experienced operators or individuals who have attended process technology school.

require operators to take a refresher troubleshooting class after this first one, even years later.[264] The troubleshooting course was not unit-specific, nor did it discuss issues critical to unit startup, such as calculating material balance or the hazards of high liquid levels.

O.1.3 On-The-Job Training

On-the-job training consisted of a board operator-in-training working shifts with a Process Technician (PT); abnormal situations, like unit startup or unit upset, are less likely to be covered in this type of training. When training is focused on what is taught on-the-job, the operator will be prepared to deal only with problems or issues that come up during those shifts (API, 2001). But abnormal situations require the most skill, knowledge, and critical thinking. And an operator's ability to perform optimally on infrequent tasks will deteriorate over time if those tasks are not performed (or at least practiced) routinely.

O.1.4 Computerized Training Program

BP's computerized training program required operators to read through a policy or procedure, then take a multiple choice test to determine if they had learned the information. The questions were factual in nature, not theoretical. For example, a question that asks what an LAH-5006 alarm indicates does not provide knowledge/reasoning on the alarm's importance, nor does it provide the operator with the engineer's design intent. Training that answers the question "why?" for the critical actions the operator is responsible for will help develop operator understanding of the unit and thereby improve troubleshooting capabilities. An understanding of the process unit, how it runs and why, and not just the memorization of facts, make operators better able to deal with abnormal situations.[265]

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[264] Interview testimony of the head of the Learning & Development department at the time of the incident.

[265] Trevor Kletz, as quoted in Labor Occupational Health Program, U. of CA, Berkeley, in *Human Factors Curriculum for Refinery Workers*.

O.2 Training Certifications

In April 2004, the Day Board Operator was certified that he had the necessary knowledge to conduct unit startup, when a PT tested him verbally. Prior to that certification, the last time the Day Board Operator received refresher training on ISOM unit startup was when he took a computerized training course February 16, 2000. Most raffinate-specific training was last reviewed in 1993.[266]

The ISOM unit board operators and PTs were collectively behind in their training. According to company records, at the time of the incident not one board-certified individual had completed more than 44 percent of training.[267]

According to BP's "Guideline for Assessing Minimum Unit Staffing Levels to Meet Process Safety Requirements," operators were expected to spend five hours per year reviewing startup and shutdown procedures as part of their normal operating duties.[268] The CSB concludes that, due to the hazards of unit startup and the increased likelihood of incidents at such a time, this amount of time for startup/shutdown procedural review is insufficient.

No Standard Operating Instructions (SOIs) existed for the Board Operator position at the time of the March 23, 2005, incident,[269] and the training materials specific to the board operator position were limited in scope and detail. When the MOC was conducted for the addition of the NDU responsibilities to the AU2/ISOM board operator, an action item was to develop a training plan for the board operator position in accordance with SH-PSM-5, "Training for Process Safety." The resolution to this action item was to add the NDU training requirements to the board operator training matrix, which merely outlines the

[266] TXC Refinery Team Status Report, VTA Report, through March 23, 2005.
[267] TXC Refinery Team Status Report, VTA Report, through March 23, 2005.
[268] "Guideline for Assessing Minimum Unit Staffing Levels to Meet Process Safety Requirements," June 3, 1996.
[269] BP response to CSB doc request 34, item 39, May 26, 2006.

process safety standards, guidelines, and training guides that the board operator is required to read and understand.

The 1998 Memorandum of Agreement between the company and the Union states that operators are expected to "satisfactorily complete the process unit, regulatory, and refinery training requirements" and that "with [the] Supervisor, jointly identify plan to develop and enhance skills to optimize job performance."[270] Many of the operators, including the Day Board Operator, had not completed their training, and none of the ISOM/AU2/NDU unit operators had performance plans in place.

Board operator training did not adequately cover abnormal situation management; as a result, the Board Operator was ill-prepared to lead a raffinate unit startup. Workers must develop an accurate and in-depth understanding of how the process system works to diagnose process upsets and understand the consequences of their actions, and "the only way such an understanding can be built is for operators to be thoroughly trained not only in what or how to do something but also in *why* to do it" (API, 2001).

[270] HiPRO Memorandum of Agreement between BP Texas City and Pace, no. 4-1 (1998), page 127.

APPENDIX P: Distraction Not a Contributing Factor

Early in the investigation, evidence suggested that distraction may have also contributed to the three-hour delay in sending heavy raffinate from the tower out to storage. These factors were investigated, and the CSB determined that distraction did not likely contribute to the incident.

At approximately 12:45 p.m., a safety meeting was held in the central control room immediately adjacent to the control board. Approximately 25 people attended this weekly meeting, including operators, engineers, supervisors, and the superintendent. The meeting lasted about 20-25 minutes, breaking around 1:10 p.m.[271] The start of this meeting was at a critical point in the unit startup: the ISOM operations crew realized heavy raffinate needed to be removed from the tower and sent to storage at 12:40 p.m. (section 3.5.7). After reviewing historical alarm data and control board records, the CSB did not find that the meeting discussions or activities impacted the Board Operator's response time to any alarm or instrument reading during the meeting. The decisions the operators made prior to (not during) the meeting led to the tower overfill. The CSB cannot speculate that the Board Operator would have made any decisions or moves on the control board differently had the meeting not taken place.

Phone calls were an unlikely distraction for the Board Operator. The central control board had two phones that the Board Operator was responsible for answering. Based on phone records, 28 calls were received or made between 6:25 a.m. and 1:20 p.m.; only 15 were made between the critical time period of 10:00 a.m. and 1:20 p.m. The longest of these 15 calls was 2 minutes, 6 seconds; 11 of the 15 calls were less than 1 minute. Phone calls labeled "potential distractions" in other published reports were not a significant distraction for the Board Operator on March 23, 2005. These calls were actually made by individuals uninvolved in the ISOM unit startup activities from a different unit control room in another building

[271] Interview testimonies of those who attended revealed that the meeting adjourned at approximately 1:10; this contradicts BP's investigation report, which states that the meeting ended at 1:00 p.m.

outside of the AU2/ISOM/NDU complex. Based on this data, the CSB has concluded that the phone calls were not a distraction to the Board Operator during unit startup.

P.1 Possible Distraction Due to Understaffing

The CSB focused its investigation on the actions and decisions of the Board Operator, because his role on the day of the incident has come under the most scrutiny. However, the CSB has noted that a possible distraction may have occurred outside the central control room. The one person in the ISOM unit with the technical knowledge and experience to assist the Board Operator control the board during the abnormal condition of unit startup – the Lead Operator – was distracted with other duties unrelated to startup. The Lead Operator was monitoring three different contractor crews, completing authorization-to-work documentation, working with others to obtain the gasket for the ISOM reactor section, and training two new operators. While he had the familiarity and skill to help the Board Operator troubleshoot unit startup issues, his assigned position as an outside operator hindered his ability to do so. In interview testimony he admitted that his responsibilities kept him too busy to even attend to the satellite control room board throughout the morning.

APPENDIX Q: Prior Incidents

In 2004, the Texas City plant manager gave a sobering "Safety Reality" presentation was given by the Texas City plant manager to 100 supervisory personnel. The plant manager spoke of the 23 deaths at the plant in the previous 30 years; on average, one worker had died every 16 months. In 2004 alone, three major accidents resulted in three fatalities. Yet, in 2004, BP Texas City had the lowest OSHA recordable injury rate[272] in its history, nearly one-third the oil refinery sector average.

As a result of this history of serious incidents, OSHA listed the BP Texas City refinery in April 2005 under its "Enhanced Enforcement Program for Employers Who are Indifferent to Their Obligations" under the OSH Act. Out of the March 23, 2005, incident, in a settlement agreement, BP paid the largest OSHA fine in history of over $21 million. The settlement agreement incorporated 301 willful violations.

After the ISOM incident, BP experienced additional major incidents at its Texas City refinery. A July 28, 2005, incident in the Resid Hydrotreating Unit (RHU) resulted in a shelter-in-place for 43,000 people and BP reported $30 million in plant property damage.[273] An August 10, 2005, release in the Cat Feed Hydrotreating Unit (CFHU) also resulted in a shelter-in-place order and $2 million in property damage. Then on July 21, 2006, the BP Texas City refinery had an additional fatality in an accident involving a motorized man-lift. In the last 32 years, the BP Texas City refinery has had 39 fatalities, one of the worst cumulative death tolls of any US workplace in recent history.

[272] The OSHA recordable injury rate is the annual number of injuries and illnesses per 100 full-time workers. The OSHA injury rate, which excludes fatalities, is a normalized rate that is used for comparison across industries.

[273] The CSB has published a Safety Alert addressing important issues related to this incident, available at the CSB website, http://www.csb.gov/completed_investigations/docs/RHUBulletin.pdf

Q.1 Texas City Blowdown System Incidents

The blowdown drum and stack have experienced a number of releases resulting in fires or significant vapor clouds at or near ground level since its construction in 1953. In 1957, the blowdown drum was moved within the ISOM unit to its current location in the northwest corner, according to Amoco's mechanical inspection records "to eliminate a dangerous fire hazard which prevailed under certain wind conditions." The CSB documented eight serious ISOM blowdown drum incidents from 1994 to 2004. In two, the blowdown system caught fire; in six, the blowdown system released flammable hydrocarbon vapors that resulted in a vapor cloud at or near ground level.

The CSB determined that the ISOM blowdown stack caught fire twice: once in 1998 and once in 2000. On October 4, 1998, the ISOM blowdown stack caught fire during stormy weather, which had caused a unit upset. The fire was extinguished by injecting steam into the blowdown system. Amoco management did not investigate. In the July 23, 2000, incident, the stack again caught fire, fueled by leaking pressure relief valves on the hydrogen driers. Steam, quench water, and a flow of nitrogen gas were opened to the blowdown system, but the fire continued over five 12-hour shifts. On the third day, the hydrogen driers were shut down and the fire on the blowdown stack extinguished. Texas City managers did not investigate. Neither of these two ISOM blowdown fire events was recorded in any incident reporting database.

The CSB determined that six ISOM blowdown incidents from 1994 to 2004 resulted in a flammable vapor cloud at or near ground level. These blowdown releases could have been more serious if the vapor cloud had found a source of ignition. In February 1994, there were three major releases of flammables from the ISOM blowdown stack at the Amoco Texas City refinery. In one, on February 12, 1994, the 115-foot (35 m) tall DIH tower filled with liquid, which led to the emergency relief valves opening to the ISOM blowdown system. A large amount of vapor was seen coming from the blowdown drum; high flammable vapor readings were measured at ground level in the area. The ISOM unit was shut down and the plant firefighters responded by fogging the area with fire monitors until the vapor cloud dissipated. Leaking DIH relief valves caused a similar incident on February 17, 1994, that resulted in a vapor release out of the blowdown stack. The fire crew was called out and placed on stand-by. A section of the ISOM was shut down to stop the release.

Amoco conducted a safety investigation and issued an incident report for the two serious February 1994 ISOM blowdown releases that identified nine action items; however, four items were not completed. Two of the action items called for reviewing the adequacy and the operation of the blowdown system. These action items were assigned to the area superintendent but were not signed off as completed, and no changes were made to the blowdown drum or stack as a result of the incident.

Another serious ISOM blowdown incident occurred later that same month. On February 27, 1994, the ISOM stabilizer tower emergency relief valves opened five or six times over four hours. A large vapor cloud was observed near ground level. The vapor release was reported as an environmental event. In the event log, the incident is described as a single relief valve discharge that lasted two or three minutes releasing 100 pounds of pollutants. No safety-related incident report was written.

On May 8, 1995, the 8-inch chain vent valve off the raffinate splitter tower overhead piping was inadvertently left open for over 20 hours during a raffinate section startup, resulting in a significant flammable vapor release out the blowdown stack. Hydrocarbons vapors were reported as “pouring out” of the blowdown drum in the ISOM logbook and high flammable vapor readings were measured at ground level. The fire department was called and quench water was started to the blowdown drum. Eventually the 8-inch overhead chain valve to the blowdown was closed after operations personnel discovered that it was open.

An environmental investigation indicated that operator error was the cause of the incident. The report about the incident stated the 8-inch chain valve should not have been used to vent the splitter tower during the startup. The need to vent the tower during startup is acknowledged in the report because “the tower pressure easily raises to 45-50 psig, at least three times its normal operating pressure.” An ISOM operator mistakenly opened the chain valve all the way when he believed he was closing it. That the valve was 30 feet (9 m) above the location where it was chain-operated at ground level and just above a solid deck made it difficult to visually check the position of the valve.

The report recommendations addressed procedures and warnings, but not the known hazards of the ISOM blowdown drum. Of the seven report recommendations, one called for a review of the startup procedure “to minimize/eliminate” the need to use the chain valve vent to the blowdown drum and for improving the visibility of the valve to the operator. Despite the report’s admonition against using the chain valve to vent the splitter, Amoco managers did not remove the chain that facilitated the use of the valve, tag the chain to warn against its use, or reference the hazards of venting to the blowdown system in the startup procedure. Rather, after this incident, “open” and “closed” were inscribed at the appropriate location where the chain exited the bottom of the decking facing the ground as an aid to operators using the chain valve. Witness reports and process data indicate that tower startup overpressure events and the use of the chain valve to vent pressure to the blowdown drum occurred in most of the startups in the five years prior to the incident.

No evidence existed that any of the other of the 1995 environmental reports’ recommendations had been implemented or safety investigation reports written. Despite the large flammable vapor release, the report did not question the safety of the blowdown drum, nor did it reference the previous 1994 blowdown incident report written just a year earlier that called for a safety review of the adequacy of the ISOM blowdown system.

On January 16, 1999, the night crew was conducting a partial ISOM unit shutdown that required draining liquid from process equipment into the blowdown system. The draining of a large amount of liquid into the blowdown drum resulted in liquid flowing into the sewer system by way of the piping that was chained open off the drum to the sewer. The high level alarm on the blowdown drum, below the outlet of the piping to the sewer, should have been triggered by the rising high liquid level, but was not. Underground sewer boxes designed to hold and separate out liquid hydrocarbons filled and released flammable vapors from the box seals, resulting in a significant vapor cloud. The ISOM logbook notes that the sewer boxes and blowdown drum "are full of oil." Operators fogged the area with fire monitors until the vapor cloud dissipated. BP management did not report the release as either an environmental event or a safety incident.

On March 25, 2004, the DIH tower pressure relief valves again lifted after a short loss of electric power to the ISOM unit, resulting in a significant vapor cloud at or near ground level. Afterward, the process equipment was restarted and tower pressure retuned to normal. The incident was recorded as an environmental event. The ISOM logbook, and another reporting record, "After Action Review," stated that the relief valves lifted for 12 minutes. However, the environmental reporting records that calculated the emissions to atmosphere state a release of 3.35 minutes. One released hydrocarbon component, hexane, was reported close (4,015 pounds) to the reportable quantity of 5,000 pounds. BP's environmental emissions calculations note that if the ISOM unit had been connected to a flare header, total emissions would have been less than 150 pounds. No incident investigation report or safety review of the blowdown drum system was generated as a result of this vapor cloud incident.

Only two of the eight serious ISOM blowdown drum incidents were investigated as safety incidents, despite the observed fires and associated large vapor clouds. Four of the six blowdown vapor cloud releases were reported only as environmental events; three of the eight were not reported in any database.

To obtain information about prior incidents, the CSB needed to gather data from a variety of sources including interviews, logbooks, environmental reports, and fire department records. Other than the environmental event log, no central database contained reports on the eight incidents. The two more-detailed reports of the incidents in 1994 and 1995 were given to the CSB months later.

In 2004, an incident involved a liquid hydrocarbon release out the blowdown stack in the Ultracracker process unit adjacent to the ISOM. In the Ultracracker, pressure relief valves opened and would not reseat, discharging liquid hydrocarbons to the blowdown drum, and no transmitter existed to signal the operator that the pressure was approaching the relief valve set-point. The high level switch on the blowdown drum did not activate and warn operators that the drum was rapidly filling with liquid. A supervisor observed that “liquid began to spew out of the top of the [blowdown system],” which then fell to the ground level. The unit evacuation alarm was sounded. The fire crew responded and fire monitors were sprayed to cool the released liquid and disperse the vapor. The process unit was shut down, and eventually the relief valve reseated and shut off the liquid flow to the blowdown system.

The Ultracracker incident investigation did not review or identify the blowdown drum design as a cause of the accident. The investigation report focused on operator error and the malfunctioning high level switch. The report found that 840 gallons of liquid hydrocarbons were spilled; however, the report did not discuss the inadequate drum size or that the stack was open to atmosphere as causes leading to the release.

Q.2 Raffinate Splitter Tower Upsets During Startup

BP did not follow its own policy requiring that previous raffinate splitter tower start-ups with high pressures be investigated. As Section 3.1.1 describes, nearly three-quarters of all ISOM raffinate section startup in the five years prior to the incident involved splitter tower high pressures and levels. BP’s environmental reporting procedures required that any event involving the lifting of relief valves to the blowdown drum be reported in its incident database. Since 2003, two of the startups had pressure surges over the relief valve set-point of 40 psig (276 kPa), likely resulting in discharge to the ISOM blowdown system. However, these high pressure events did not trigger an incident investigation.

The high level events in the previous splitter tower startups should have been investigated. In 15 out of 19 previous startups, the splitter tower level rose above the range of the level transmitter; in eight, the level was above the transmitter range for over one hour. The CSB has determined that in none of these previous high level startups did the tower level rise as high as it did during the March 2005 incident. When the tower is operated in this condition it becomes much easier to overfill. Overfilling a process vessel can lead to process upsets, unit shutdown, or the discharge of flammable liquid to atmosphere. Moreover, as discussed in Section 3.9, BP did not designate a safe operating limit for high tower level, despite previous incidents such as the February 1994 incident when another ISOM distillation tower, the 115-foot (35-m) tall DIH tower, overfilled, leading to a unit shutdown and large release out of the blowdown and stack. The previous startups with high tower level were near-miss[274] incidents that could have led to a vapor cloud explosion if the cloud had found an ignition source. Investigations of these incidents could have resulted in improvements to tower design, instrumentation, procedures, and controls.

[274] The CCPS defines a near-miss as "an event in which an accident (that is property damage, environmental impact or human loss or an operational interruption could have plausibly resulted if circumstances had been slightly different." (CCPS, 2003, p.437).

APPENDIX R: Emergency Relief System Design Analysis

The CSB reviewed the BP design basis calculations for the installed raffinate splitter tower relief system, and had a contractor perform emergency relief design calculations on the raffinate splitter tower to determine if it met the requirements of the American Society of Mechanical Engineers (ASME) "Boiler and Pressure Vessel Code, Section VIII – Unfired Pressure Vessels," and other applicable industry guidelines, such as API 521 (Fauske & Associates, 2006).

The BP sizing calculations for the safety relief valves on the raffinate splitter tower were compared against those obtained from a digital simulation computer program. The heat and material balance differential equations, which describe the transients, and the fluid dynamic equations, which describe the flow capacity of an emergency relief system, were solved by numerical integration. The physical properties and vapor-liquid equilibrium constants for the materials present were read into the computer program from a physical property data file. All physical properties were calculated as a function of temperature in accordance with recognized thermodynamic models. Program input and output describing the physical situation were checked for consistency and printed to provide a written record of the calculations. The mass of each component was also continually checked to ensure a realistic value. A variable time step controlled by the rates of temperature and pressure changes was used to maintain numerical accuracy for stiff systems.

The computer program incorporated the American Institute of Chemical Engineers (AIChE); DIERS, (Fisher et al., 1992; Fisher, 1991) and CCPS (1998) technology for both viscous and non-viscous, flashing, frozen, and hybrid two-phase flows through emergency relief devices and pipes. Also included were routines to calculate inlet pipe pressure drop and discharge pipe backpressure for choked and sub-critical vapor, two-phase, and sub-cooled liquid flows from safety valves and breather vents. The program reported choked or unchoked and turbulent or laminar flow through each device and associated inlet or discharge pipe, and the first occurrence of safety valve inlet pipe high-pressure drop or discharge pipe high backpressure. Warning messages were provided if the emergency relief devices cannot maintain the system pressure to meet ASME Pressure Vessel Code and API requirements (ASME, 2001; API, 2000, 1997, & 1994).

Based on a review of records from BP, the original design basis of the safety relief valves installed on the raffinate splitter tower was the heat input at the production capacity and flow at an accumulation of 1.16 (process upset/multiple relief devices) of the 70 psig (483 kPa) Maximum Allowable Working Pressure (MAWP). When the MAWP of the raffinate splitter tower was derated to 40 psig (276 kPa), the area of the safety relief valves was not increased to reflect flow at the lower set pressure, nor was the production capacity of the unit reduced. Neither does documentation exist showing that the maximum flow rate of the fuel available to the raffinate splitter feed preheater/fractionator reboiler was reduced.

The relief system design and design basis (controlling case) for the raffinate splitter tower with a MAWP of 40 psig (276 kPa) is reflux failure, with a worst credible scenario total loss of condenser cooling at the design capacity. Unfortunately, BP used a partial loss of cooling with reflux, rather than the total reboiler duty with no reflux, for the recent calculations, resulting in a design error.[275] The original emergency relief system design for the raffinate splitter with a 70 psig (483 kPa) MAWP does not appear to contain this error.

[275] “RV Summary – RV-1001GA” (February 5, 2003).

The raffinate splitter reboiler duty is rated as 59.6 MM BTU/hr .[276,277,278] The raffinate splitter overhead condenser duty is rated as 59.4 MM BTU / hr .[279,280,281] Using a latent heat vaporization range of 113.3 BTU/lb,[282] the required capacity of the installed emergency relief at an accumulation of 1.16 for the 40 psig (276 kPa) MAWP would be 525,215 pph.

API Recommended Practice 521, Section 3, "Determination of Individual Relieving Rates," and Section 3.6.2, "Cooling or Reflux Failure – Total Condensing" provide guidance. The design value (wide-open capacity) should be used for the process heat input prevailing at the time of relief for condenser failure. API 521 suggests in "Fan Failure" (Section 3.6.4) that because of natural convection effects, credit for a partial condensing capacity of 20 to 30 percent of the normal duty is often used, and that the capacity of the relief valve is then based on the remaining 70 to 80 percent of the duty.

The raffinate splitter overhead condenser uses a variable pitch fan; if the pitch mechanism fails, cooling capacity can be reduced. Failure of the reflux that results from pump shutdown or valve closure will flood the condenser, which equals a total loss of cooling. A valve sized for total cooling failure should be used for this relief scenario. The relief system design and design basis for the safety relief valves BP provided for the raffinate splitter tower with a MAWP of 40 psig (276 kPa) is not conservative and is inadequate.

Three Consolidated bellows-type safety relief valves were installed (Table R-1) to provide the required emergency relief for the raffinate splitter system with the current MAWP of 40 psig (276 kPa), which was derated from 70 psig (483 kPa) in 2003 due to corrosion considerations.

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[276] Ibid.
[277] "E-1101 HUF Fractionator (in Raffinate Service)" – RV-1001GA" (January 21, 2003).
[278] "Relief Valve Scenarios" – RV-1001GB" (October 20, 2002).
[279] "RV Summary – RV-1001GA" (February 5, 2003).
[280] "E-1101 HUF Fractionator (in Raffinate Service)" – RV-1001GA" (January 21, 2003).
[281] "Relief Valve Scenarios" – RV-1001GB" (October 20, 2002).
[282] "RV Summary – RV-1001GA" (February 5, 2003).

Table R- 1. Specifications of safety relief valves installed on the raffinate splitter tower

Safety Relief Valve	Original Pressure Setting (psig)	Present Pressure Setting (psig)	Inlet Pipe Diameter (inches)	Discharge Pipe Diameter (inches)	Valve ID
4P6	70	40	6	6	RV-1001GC
8T10	74	41	10	10	RV-1001GB
8T10	74	42	10	10	RV-1001GA

The capacity of and backpressure on these safety relief valves were evaluated using a 0.95 coefficient of discharge appropriate for a Consolidated bellows safety relief valve, an ASME code capacity reduction factor of 1.0, and the API 520 consensus Kb factor to account for the decreasing lift and resultant flow reduction of bellows safety relief valves as the discharge pipe backpressure increases. The flow capacities were evaluated at 1.16 MAWP values with set pressures of 40 and 70 psig (276 and 483 kPa) (Table R-2).

Table R- 2. Flow from the safety relief valves on the raffinate splitter

No Discharge Pipe Header		14-Inch Discharge Pipe Header		20-Inch Discharge Pipe Header	
Tower (Top-Mounted SRVs)	Flow Rate (pph)[283]	Flow Rate (pph)	% Backpressure	Flow Rate (pph)	% Backpressure
Vapor Flow (40 psig MAWP)	416,467	213,339	60.8	378,862	37.0
Vapor Flow (70 psig MAWP)	637,441	316,194	61.8	542,942	38.0

As Table R-2 shows, excessive backpressures of 60.8 percent of the safety relief valve set pressures were found for vapor flow from the bellows safety relief valves for a MAWP of 40 psig (276 kPa) and 61.8 percent for a MAWP of 70 psig (483 kPa). These high backpressures show that the diameter of the bellows safety relief valves discharge pipe header should have been 20 inches, rather than 14, for either the 40 or the 70 psig (276 or the 483 kPa) MAWP design calculations.

[283] @ 1.16 Pset.

The ASME Code, Appendix M, Para. M-8 states: "The sizing of any common discharge header downstream from each of two or more pressure relieving devices that can reasonably be expected to discharge simultaneously shall be based on the total of their outlet areas…." This design error should have been caught by inspection, during the many PHA revalidations, as part of the OSHA PSM "relief system design and design basis" calculations, or when the pressure relief calculations were completed that supported lowering the MAWP of the raffinate splitter.

The raffinate splitter safety analyses, conducted by the contractor who designed the Penex reactors for the ISOM unit,[284,285] identified that the 14-inch diameter discharge pipe header from the raffinate splitter to the blowdown drum was not large enough to handle relief loads, which were calculated based on the full reboiler furnace firing rate when reflux is lost. During power, reflux, or condenser failure, the built-up backpressure on the raffinate splitter relief valves was found to approach 85 percent of the set pressure. The contractor recommended that the instrumentation be modified, but BP never did, nor were the calculations rechecked during many subsequent opportunities.

BP has not provided relief system design and design basis backpressure calculations for the safety relief valve discharge pipe header from the raffinate splitter to the blowdown drum, as required by the OSHA PSM standard [29 CFR 1910.119(d)(3)(i)(D)].

The sizing information[286] for the safety relief valve protecting the raffinate splitter reflux drum reflects only vapor flow. The reflux drum operation was changed to operate liquid-full. The safety relief valve should have been sized for a sub-cooled liquid, or flashing two-phase vapor-liquid flow, instead of vapor.

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[284] Untitled (Raffinate Splitter Safety Analysis), Litwin Engineers & Constructors Inc., (undated).

[285] "Raffinate Splitter Relief System", Litwin Engineers & Constructors, Inc. (October 30, 1986).

[286] "ISOM RV Walkdowns, RV-1002G, Raffinate Splitter Reflux Drum (F-1102) (January 5, 2005) w / Attachments.

The sizing records[287] for the safety relief valve that protects the raffinate splitter feed surge drum reflect a requirement to install a bellows kit in the safety relief valve to address concern about pressure dropping in the outlet piping. The information furnished by BP does not indicate that this change was made.

The sizing calculations[288] for the safety relief valve protecting the raffinate splitter reboiler furnace tubes reflect a requirement for flashing two-phase vapor-liquid flow, but have not been furnished by BP. If the calculation used for sizing this valve did not consider two-phase vapor-liquid flow -- a possibility due to the age of the furnace -- then the effluent system may be incapable of handling the rate and amount of liquid likely to be released.

BP has not furnished calculations justifying the projected release of the vapor flow from the safety relief valves on the raffinate splitter tower to the blowdown drum and then to the atmosphere. Dispersion modeling should have been completed for discharges from the blowdown drum stack to ensure that a flammable vapor cloud large enough to cause damage could not form.

[287] "ISOM RV Walkdowns, RV-1000G, Raffinate Splitter Feed Surge Drum (F-1101)" (January 4, 2005) w/attachments.

[288] "ISOM RV Walkdowns, RV-1004G, Raffinate Splitter Reboiler Furnace Tubes (B-1101)" (January 10, 2005) w/attachments.

APPENDIX S: Raffinate Splitter and Blowdown Drum Instrument History, Testing, Inspection, and Analysis

This appendix contains additional information about the four instruments identified in the CSB's report as causally related to the March 23, 2005, incident at BP Texas City. The contents of the appendix are:

- A brief summary of the CSB testing and inspection of the instruments.
- A discussion of the failure analysis and possible failure mechanisms for each instrument.
- A tabulation of the work history for each instrument, compared with manufacturer recommendations.

S.1 Instruments Involved

The CSB analysis identified four instruments as causally related to the incident:

- LT-5100 Raffinate Splitter Level Transmitter
- LSH-5102 Raffinate Splitter High Level Alarm
- LSH-5020 Isom Blowdown Drum High Level Alarm
- PCV-5002 Raffinate Splitter Vent Valve to 3-lb Relief Header

Additionally, the sight glass associated with the raffinate splitter level transmitter was dirty and unusable.

S.2 Physical Failure Causes

The CSB inspected and tested the instruments (above), to determine the causes of their failures. The next section discusses the physical conditions that caused the failures, and the systemic failures that allowed the physical conditions to occur.

S.2.1 Description of Instrument Testing

The CSB tested the instruments and a valve onsite to determine their condition and functionality in their post-incident condition. The CSB then removed the instruments and tested, disassembled, and inspected them in a third-party shop, following a written protocol.

S.2.2 Raffinate Splitter Level Transmitter LT-5100

The raffinate splitter level transmitter is a torque-tube displacement instrument[289] that must be calibrated for the specific gravity[290] of fluid to be measured at the fluid's normal operating temperature. When the raffinate splitter bottoms' temperature increased on the day of the incident, the specific gravity of the fluid in the raffinate splitter dropped below the calibration setting of the transmitter, causing it to read less than 100 percent and *decreasing* even as the tower over filled.

During field-testing the CSB found the raffinate splitter level transmitter to be functioning with its calibration set at a fluid specific gravity of 0.8. At ambient temperature, the transmitter indicated slightly less than 100 percent level when the raffinate splitter liquid level was above the displacer (when the transmitter was flooded).

The meter was removed from the raffinate splitter column and taken to a third-party shop for inspection and testing. The transmitter was tested using three fluids with different specific gravities. Analysis of these tests indicated that the flooded transmitter would read 100 percent level at a specific gravity of 0.705 (Figure S-1), close to, but slightly higher than the ambient temperature specific gravity of the raffinate splitter contents of 0.67. This is consistent with the field test results conducted with the tower liquid at ambient temperature.

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[289] The transmitter measures changes in the net weight of a displacer body due to buoyancy as the liquid level varies along the displacer. Once the tower level reaches the maximum height of the displacer body, the buoyant forces stabilize; therefore, this type of level sensor is incapable of transmitting levels above 100 percent of its range.

[290] Specific gravity is the relative density of a fluid, compared with water, at a specified temperature.

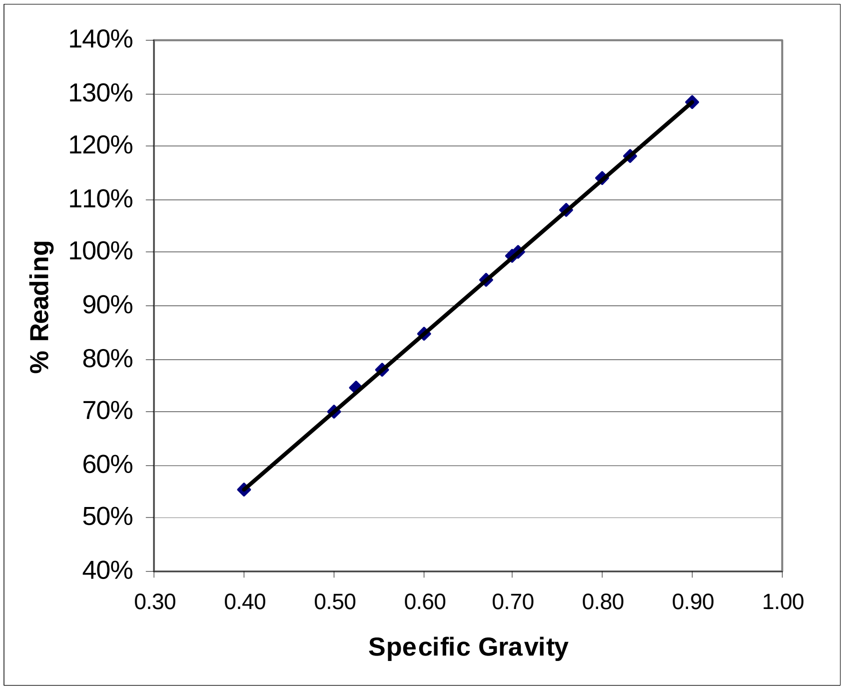


Figure S- 1. Calculated LT-5100 flooded reading versus specific gravity

The specific gravity of the hydrocarbon liquid in the raffinate splitter tower is strongly temperature-dependent. At 300°F, the temperature in the base of the raffinate splitter when it overflowed, the specific gravity is about 0.55 (Figure S-2). As Figure S-1 shows, at a specific gravity of 0.55 the transmitter would indicate a level of 78 percent when flooded, which matches the value observed when the raffinate splitter tower over-filled. The CSB concludes that the level transmitter was not calibrated for the specific gravity of fluid at its normal operating temperature.

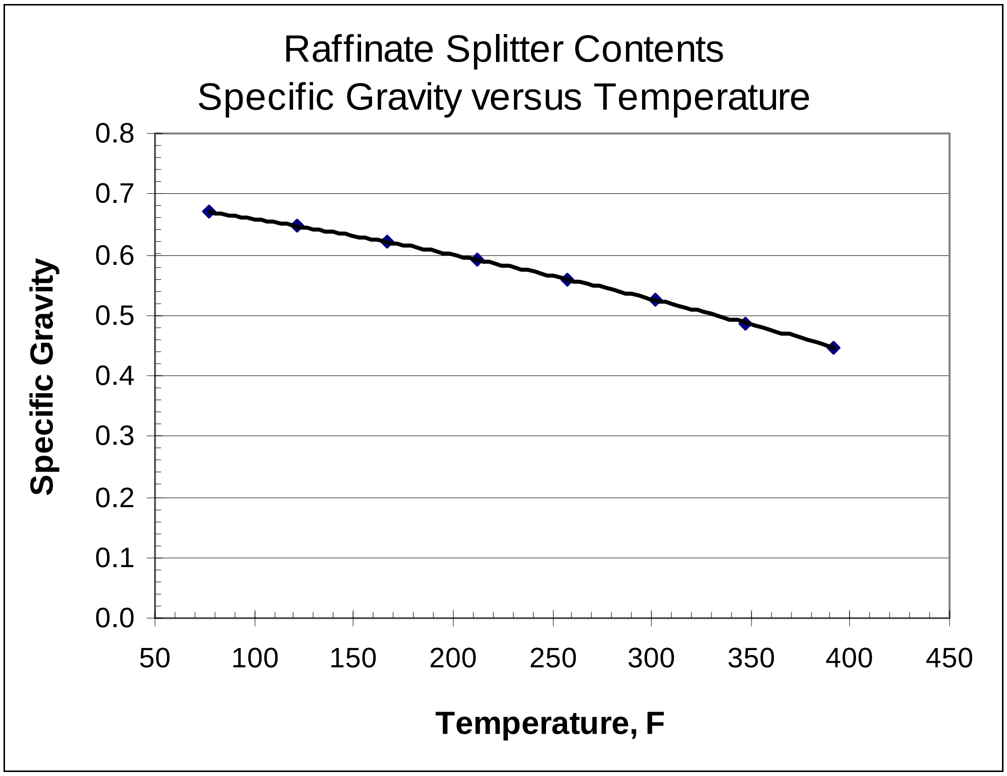


Figure S- 2. Calculated raffinate splitter feed specific gravity as a function of temperature

The CSB investigators learned that the instrument data sheet, which should have been used for calibrating the transmitter, had not been updated since 1975 when the tower was part of a different process with a different feed fluid. The data sheet had never been changed to reflect the operating specific gravity in the ISOM process; furthermore, instrument technicians responsible for maintaining and calibrating the transmitter stated that the data sheets—even if they had been updated—were unavailable to them. The CSB learned that these data sheets were filed in an engineer's office and were not typically given to technicians with work orders for instrument calibration.

The CSB learned from interviews and maintenance records that the transmitter had been noted as "troublesome" some months prior to the 2005 turnaround. The CSB investigators found that the isolation valves for the transmitter and associated sight glass had been leaking; and that the transmitter could thus not be removed for repair and calibration. While the valves were replaced in the recent turnaround,[291] the transmitter was not worked on or calibrated before the unit started up.

S.2.3 Raffinate Splitter Sight Glass LG-1002A/B

The CSB investigators observed that the sight glasses for the raffinate splitter were dirty (with stains or deposits on the inside of the glass), to the extent that the tower level could not be seen in the glass. Operator interviews confirm that the sight glass had been in this condition for years prior to the March 2005 turnaround. The same leaking isolation valves that prevented the level transmitter repair also likely prevented technicians from being able to remove and clean the sight glasses. Again, although the isolation valves had been replaced in the recent turnaround, the sight glasses were not cleaned.

The sight glasses were necessary to properly calibrate the level transmitter and alarms, as only by visually verifying the actual level in the tower could operators and instrument technicians verify the accuracy of the level instruments. Functioning sight glasses might also have allowed a field check of the column level, and warned operators that the level indication was erroneous and the level in the column was above the transmitter.

S.2.4 Raffinate Splitter High Level Alarm LSH-5102

Plant maintenance records indicate that the high level alarm on the raffinate splitter had been reported as not functioning several times in the two years prior to the incident. An instrument technician replaced part of the switch for the high level alarm; however, this repair was unsuccessful and the switch continued to function improperly. Maintenance workers indicated that the isolation valves for this instrument were leaking and further repairs could not be conducted. Plant maintenance records show several closed work

[291] Job Note 05-009R, 3/10/2005.

orders for this alarm, but maintenance workers stated that the repairs were never completed (one record shows no labor or materials was ever charged). Maintenance worker interviews confirm that the alarm had not been successfully repaired before the March 23 startup.

Post-incident, the CSB could not field-test the alarm's functionality due to the leaking isolation valves. Since the leaking isolation valves were also reported by the instrument technicians, the CSB concludes that the alarm most likely was not repaired prior to the incident. Shop-testing and -inspection revealed that the internal components were worn, misaligned, and binding, which likely prevented the alarm from working during the March 23 incident.

S.2.5 Blowdown Drum High Level Alarm LSH-5020

Operating data recovered after the incident and operator statements revealed that the high level alarm for the relief system blowdown drum did not activate when the level in the blowdown drum reached the set-point. The CSB found the displacer float for the alarm full of fluid; shop inspection revealed that the float had a hole in it. In this condition, the float would likely have either sunk to the bottom of its chamber or failed to float at the designed height for the alarm, preventing it from reaching the alarm set-point. Damage to other components of this alarm caused by the fire of March 23, 2005, prevented additional functionality testing.

Although the CSB could not conclusively determine when the damage to the float occurred (during operation or during the upset and fire on March 23, 2005), laboratory analysis of the fluid in the float indicates that the float was filled with water, sediment, and a hydrocarbon mixture with a different composition than that of the raffinate splitter feed. The CSB concludes that the hole in the high level switch float likely formed prior to the incident. Additionally, the history of problems with the functionality of the high level switch reported by operations personnel is consistent with a float defect. In response to the reoccurring problems, weekly maintenance was performed to ensure that the switch was working. However, the typical maintenance practice of steaming out the piping connections from the switch housing to the blowdown drum would not reveal the float defect.

LSH-5020 was a designated critical alarm; therefore, it was tested by instrument technicians every six months. However, the test method the instrument technicians typically used would not have revealed the float defect: they stated that they commonly used a metal rod to push the float up to test the alarm (“rodding”), which would not test the functionality of the float. The test method recommended by the alarm manufacturer and industry guidance calls for raising the chamber liquid level to check the alarm set-point, which would test the functionality of the float (Goettsche, 2005).

S.2.6 Raffinate splitter 3-pound vent valve PCV-5002

PCV-5002 was a manually-activated control valve intended to provide a vent path for non-condensable gases from the raffinate splitter overhead. These non-condensable materials, such as nitrogen, could prevent the condensation of hydrocarbon vapors in the fin fan condenser, causing excessive column pressure, especially during startups. The valve was intended to direct vapors to a common vent system (called the “3-pound vent”). Operations personnel stated that this valve failed to function during pre-startup testing, and that they were aware the valve was not working when the ISOM unit was shut down. This forced operators to manually open other valves to vent non-condensable gases during the March 23, 2005, startup.

PCV-5002 was a control valve with an air-activated mechanism (actuator) to move the valve stem. The valve failed to open in nearly all the attempts during field-testing, but did open to varying degrees through successive shop trials, indicating a possible intermittent failure. The CSB was unable to identify the likely failure mechanism for this valve; however, several possible failure causes include

- binding, signal, or motor failure of the valve actuator;

- excessive valve stem friction; and
- leaks in the signal air to the valve actuator.

The CSB found no evidence that PCV-5002 had been repaired, inspected, or subject to a preventive maintenance program in the 10 years prior to the incident.

S.3 Instrument Inspection and Testing

The CSB contracted ASBG Consulting, Inc., to inspect, test, and analyze the four instruments the CSB identified as causally connected to the March 23, 2005, incident at BP Texas City refinery. All four were field-tested to the extent possible, photographed, and examined in-situ, then transported to a third-party shop for further testing and inspection. Table S-1 provides a brief synopsis of the work performed.

Table S- 1. Field and Shop Testing and Inspection Summary

Tag Number	Field Testing	Shop Testing	Inspection
LT-5100	Calibration testing, measured transmitter outputs as the level varied in the isolated level bridle and sight glass.	Functional testing similar to field testing using a shop displacer chamber and sight tube. Tested three fluids with different specific gravities (water, low sulfur diesel, and Viscor leak detection fluid 130 BT.) Calibration testing of the transmitter by simulating level values using weights.	Disassembly and inspection for damage, corrosion, plugage, and dimensional measurement.
LSH-5102	Functionality testing attempted but not completed; isolation valves leaked.	Function tested using shop displacement chamber and Viscor leak detection fluid 130 BT.	Disassembly and inspection of all parts.
LSH-5020	None. Damage due to fire too extensive.	None. Damage due to fire too extensive.	Disassembly and inspection of all parts.
PCV-5002	Function testing by sending signals to valve actuator and observing valve movement (stroke test.)	Valve stroke test and bubble test for valve leakage.	Disassembly and inspection of all parts.

S.4 Test Results and Instrument Failure Analysis

To help identify possible failure causes, the CSB (through its contractor, ABSG Consulting, Inc.) developed a fault tree for each instrument failure. From this analysis a list of possible failure causes was derived, which were compared to the results of field and shop testing and inspections. Any potential causes not supported by the evidence were eliminated. The remaining causes were deemed probable and are underlined in the Table S-2.

Table S- 2. Test results and analysis summary

Tag Number	Test/Inspection Findings	Possible Failure Causes
LT-5100	Transmitter functioned; however, it was not calibrated for the correct fluid specific gravity at normal operating temperature.	<u>Transmitter out of calibration</u> Transmitter power insufficient Tubing or connection leaking Liquid in the tubing Pneumatic transmitter out of calibration Incorrect pneumatic transmitter setting Instrument air piping fails to transmit air to the pneumatic transmitter/loss of instrument supply/displacer chamber not level
LSH-5102	Unable to field test (leaking valves). Alarm switch failed to function during shop testing. Switch components misaligned and binding.	<u>Mercury switch wiring to the switch terminals tension excessive</u> <u>Mercury switch assembly pivot point binding</u> <u>Return spring degraded</u> Magnetic attraction between the connecting rod and mercury switch assembly not broken when the displace moves the designated distance Connecting rod movement insufficient Process fluid fails to fill the switch housing

Tag Number	Test/Inspection Findings	Possible Failure Causes
LSH-5020	Unable to field or shop test due to fire damage. Float corroded with small hole, filled with fluid. Analysis of the fluid indicates that it was not raffinate splitter feed.	Computerized control board fails to display the high-level alarm when the status of the high-level switch transitions to the alarm state Computerized control board fails to detect that the signal from LSH-5020 has changed to the alarm state Connected mercury switch not attached or improperly attached to the mercury switch assembly Electrical component shorted Float failure Process fluid fails to fill the switch housing
PCV-5002	Intermittent failure to open during field testing. Variable valve stem travel distances on successive tests.	Air signal leakage Excessive friction forces on actuator stem Torque motor failure Output module failure Nozzle failure Wiring failure Loose stem clamp Feedback arm linkage binding at pivot points Unable to determine most probable cause. Theorized transient failure or combination of the above.

S.5 Photographic Evidence

This section contains selected photographs taken during shop testing that illustrate testing and conditions.

Figure S- 3. LT-5100 cabinet showing calibration set for 0.8 specific gravity

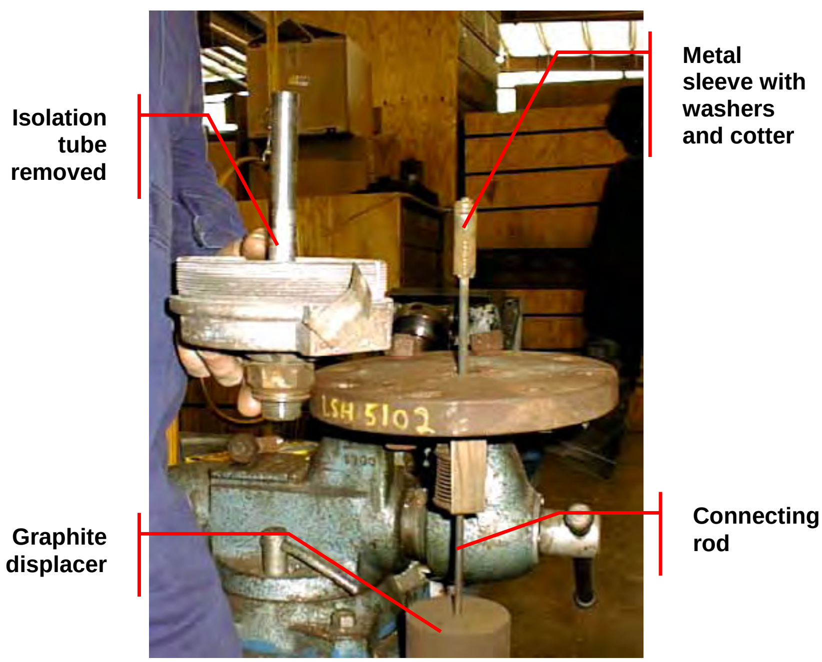


Figure S- 4. LSH-5102 internal components

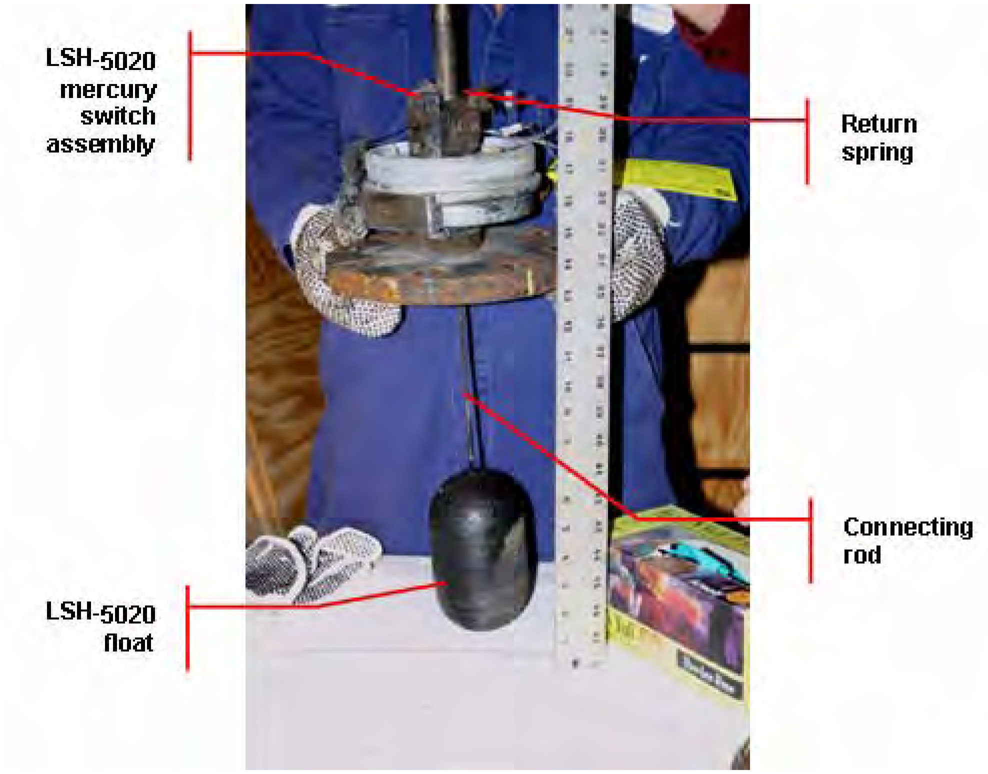


Figure S- 5. Internal components of LSH-5020 blowdown drum high level alarm

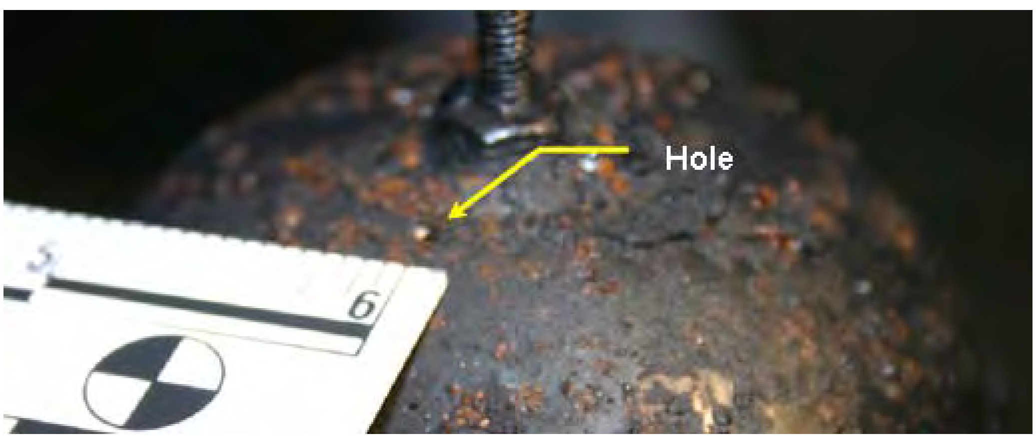


Figure S- 6. Close-up of LSH-5020 float, showing corrosion and hole

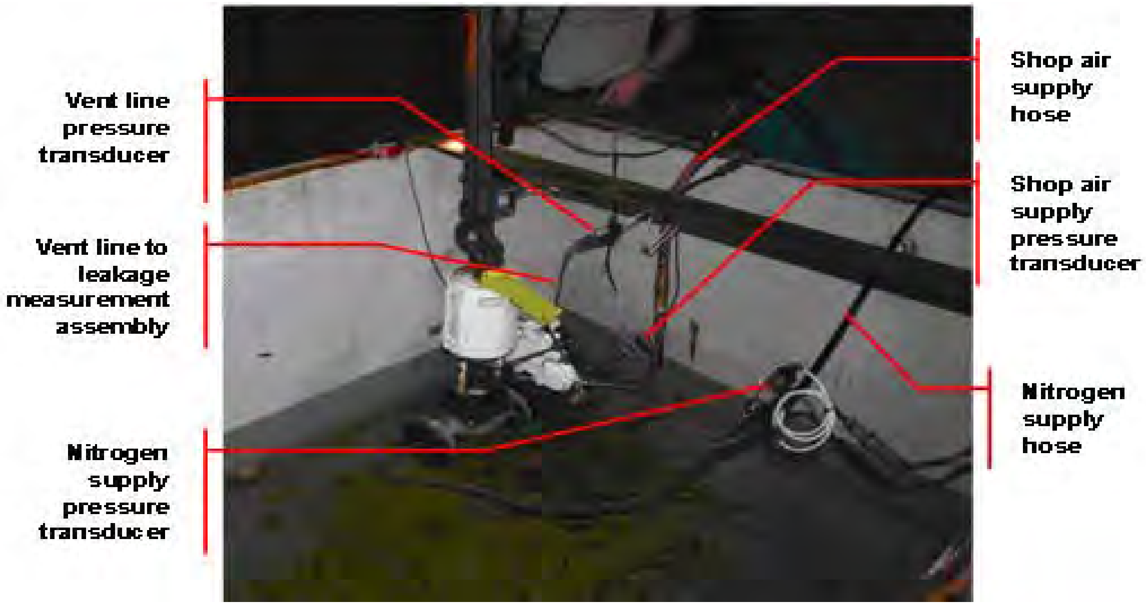


Figure S- 7. PCV-5002 shop testing

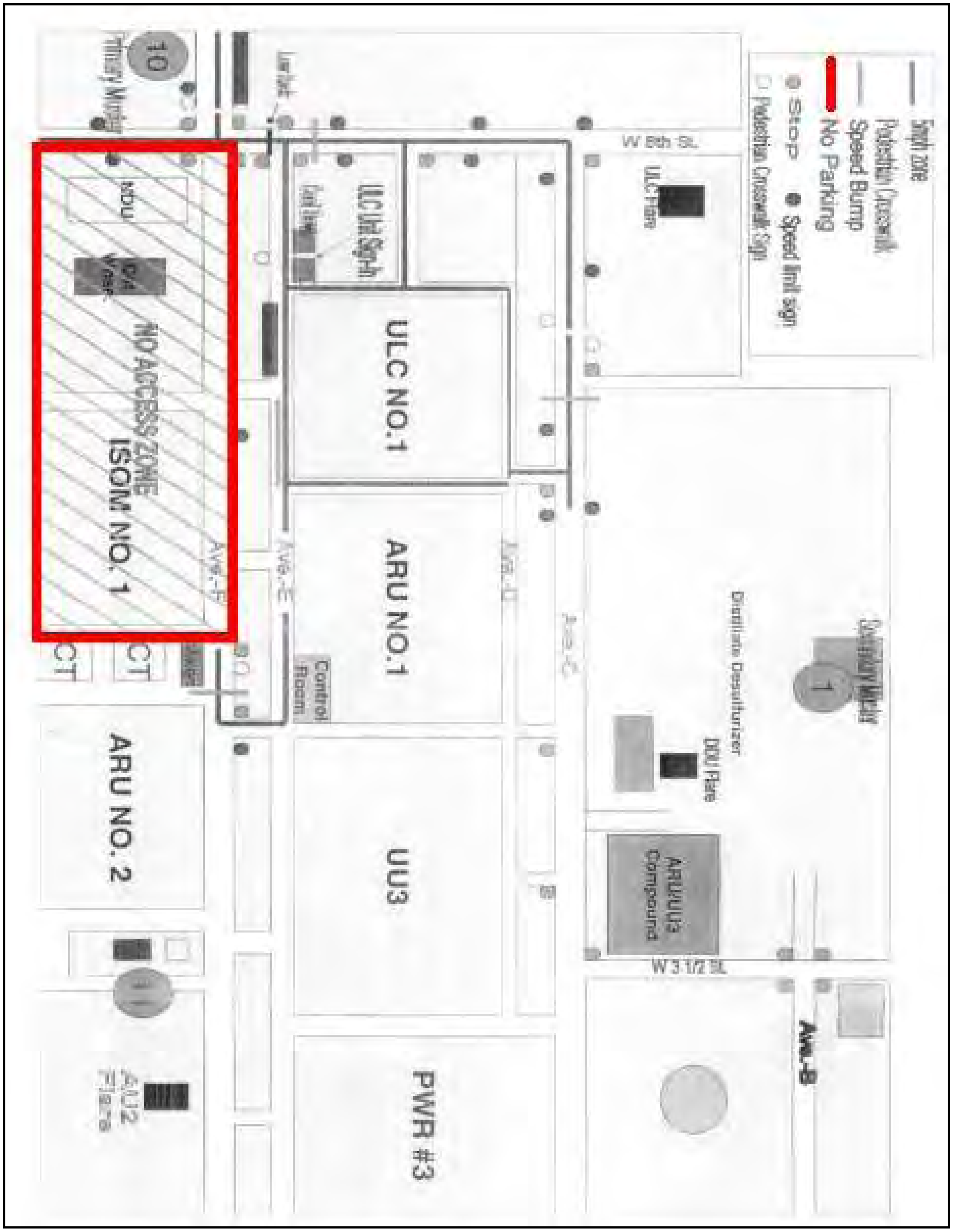
APPENDIX T: BP Management-of-Change (MOC) Policy

While reviewing changes pertaining to the raffinate splitter tower, blowdown drum and stack, and mobile trailers, the CSB noted a number of misapplications of the refinery MOC policy. As discussed in section 2.5.2.2, a pressure control valve was non-operable, but the raffinate splitter tower startup proceeded without initiating a MOC. Several changes were also made to the start-up procedures of the raffinate splitter tower without initiating MOCs.

A number of design and equipment changes to the blowdown drum and stack were not evaluated under the MOC policy, even though this equipment was designated by the refinery as "safety critical." In 1997, when the blowdown drum and stack was replaced due to corrosion, the internal diameter of the stack was reduced over three inches, from 36 inches inside diameter to 34 inches outside diameter. Although this change was characterized by the refinery as a "replacement-in-kind" involving no process changes,[1,] the dispersion of flammable vapors into the atmosphere is a function of the stack height and the internal diameter; therefore, the safety and health impacts should have been reviewed under the MOC policy. In 1998, a process hazard analysis (PHA) action item recommended chaining open the discharge valve to the sewer on the blowdown drum to prevent a high liquid level from increasing the backpressure on the relief valve headers. This action item was addressed by chaining open the valve without assessing its potential impacts on health and safety. The CCPS notes, in "Guidelines for Design Solutions for Process Equipment Failures," that locking open a valve is "not merely a common sense decision; rather at an operating facility it is a design change. It is a procedural design solution that requires a documented design basis and a subsequent safety review" (CCPS, 1998, p. 27). As Section 3.2.5 notes, industry safety guidelines recommend against putting volatile, flammable liquids into a sewer. In 2003, the blowdown drum and stack was returned to normal service after ISOM turnaround, even though an external inspection noted heavy corrosion due to hydrogen chloride (HCl) attack, and an internal inspection could not be conducted because of safety concerns that additional baffles might fall. As Section 3.2.5 discusses, the original design of the blowdown drum and stack was to separate liquid and vapor discharges, which the internal baffles helped with. A MOC was not initiated to determine if the blowdown drum and stack could still function as designed, even after some baffles had collapsed in the bottom of the drum and sections of corroded baffles were still attached to the walls. Also, no MOC was initiated to determine if the blowdown drum could function as designed without service water (supplied to the blowdown drum to cool any hot process streams diverted to the drum during an upset or unit shutdown), which had been out of service for a couple of years.

As Section 6 discussed, mobile trailers were not sited in accordance with MOC policy. Insufficient training for PHA leaders in the use of the MOC policy and its various checklists, a lack of identified responsibilities for the refinery’s turnaround organization, trailers being occupied before PHA all action items were resolved, and lack of review of MOCs all prevented the MOC policy from being implemented as was intended.

APPENDIX U: BP turnarounds traffic control map*



*The red outline has been added by CSB to highlight the “No Access/Parking” area.

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