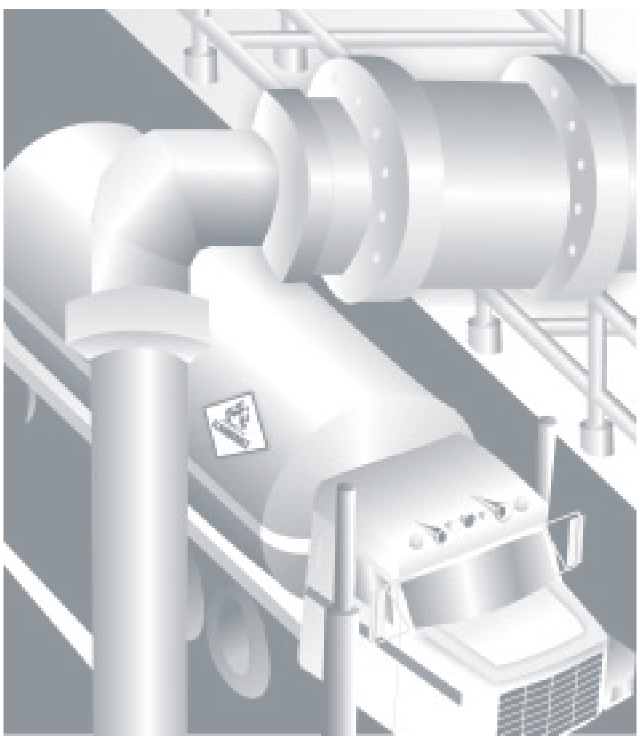
# Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines



## Safety Study

NTSB/SS-05/02

PB2005-917005
Notation 7505A

National
Transportation
Safety Board
Washington, D.C.

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Adopted November 29, 2005

National Transportation Safety Board
490 L'Enfant Plaza, S.W.
Washington, D.C. 20594

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

**Abstract:** In the pipeline industry, Supervisory Control and Data Acquisition (SCADA) systems are used to collect data from pipeline sensors in real time and display these data to humans who monitor the data from remote sites and remotely operate pipeline control equipment. This National Transportation Safety Board study was designed to examine how pipeline companies use SCADA systems to monitor and record operating data and to evaluate the role of SCADA systems in leak detection. The number of hazardous liquid accidents investigated by the Safety Board in which leaks went undetected after indications of a leak on the SCADA interface was the impetus for this study. The Board developed a survey to obtain data about the liquid pipeline industry's use of SCADA systems with input from industry. In addition to obtaining survey data, the Board visited 12 pipeline companies that had operating SCADA systems. Based on information from previous accidents investigated by the Board, survey results, and site visit results, the Board's review of SCADA systems in the hazardous liquid pipeline industry uncovered five areas for potential improvement: display graphics, alarm management, controller training, controller fatigue, and leak detection systems. As a result of this study, the Safety Board issued five recommendations to the Pipeline and Hazardous Materials Safety Administration.

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# Contents

# Acronyms and Abbreviations

| | |
|---|---|
| AGA | American Gas Association |
| API | American Petroleum Institute |
| ASME | American Society of Mechanical Engineers |
| CBT | computer-based training |
| CFR | *Code of Federal Regulations* |
| CPM | computational pipeline monitoring |
| CRT | cathode ray tube |
| HVL | highly volatile liquid |
| ISA | Instrumentation, Systems, and Automation Society |
| LDS | leak detection system |
| OPS | Office of Pipeline Safety |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| psi | pounds per square inch |
| RSPA | Research and Special Programs Administration |
| SCADA | Supervisory Control and Data Acquisition |
| WIGO | What is going on? |

# Executive Summary

SCADA—Supervisory Control and Data Acquisition—systems are a type of industrial control system used to collect data and exercise control from a remote location. In the pipeline industry, SCADA systems are used to collect data from pipeline sensors in real time and display these data to humans (controllers) who monitor the data from remote sites. Controllers, in turn, can use the SCADA system to input commands that remotely operate pipeline control equipment, such as valves and pumps. SCADA systems are widely in use in oil, gas, electricity, and municipal water systems.

For this study, the National Transportation Safety Board examined the role of SCADA systems in the 13 hazardous liquid line accidents that the Safety Board investigated from April 1992 to October 2004. In ten of these accidents, some aspect of the SCADA system contributed to the severity of the accident. The principal issue in the SCADA-related accidents investigated by the Board was the delay between a controller's recognizing a leak and beginning efforts to reduce the effect of the leak. SCADA factors identified in these accidents include alarms, display formats, the accuracy of SCADA screens, the controller's ability to accurately evaluate SCADA data during abnormal operating conditions, the appropriateness of controller actions, the ability of the controller and the supervisor to make appropriate decisions, and the effectiveness of training in preparing controllers to interpret the SCADA system and react to abnormal conditions.

This study was designed to examine how pipeline companies use SCADA systems to monitor and record operating data and to evaluate the role of SCADA systems in leak detection. The number of hazardous liquid accidents investigated by the Safety Board in which leaks went undetected after indications of a leak on the SCADA interface was the impetus for this study. The study describes SCADA systems being used at pipeline companies that transport hazardous liquids and examines the extent to which the SCADA system design helps or hinders controllers in detecting leaks and acting to limit the amount of product released.

The Safety Board developed a survey to obtain data about the liquid pipeline industry's use of SCADA systems with input from industry. The survey covered basic information about the pipeline company and its SCADA system. In total, 87 percent of the control centers targeted by the survey responded. In addition to obtaining survey data, the Board visited 12 pipeline companies that had operating SCADA systems. The Board interviewed personnel who developed and used SCADA systems for the pipeline company. A total of 69 persons were interviewed. Interviewed personnel included controllers, supervisors, and SCADA systems managers. In addition, the Board examined the SCADA system and reviewed its design and development with a company representative who was responsible for the system's operation and maintenance. The Board also reviewed SCADA-related job aids that controllers used during the course of their work. Based on information from previous accidents investigated by the Board, survey results, and site visit results, the Safety Board's review of SCADA systems in the hazardous liquid pipeline industry uncovered five areas for potential improvement:

- display graphics,
- alarm management,
- controller training,
- controller fatigue, and
- leak detection systems.

As a result of this study, the Safety Board issued five recommendations to the Pipeline and Hazardous Materials Safety Administration.

# Chapter 1

# Introduction

## What is SCADA?

SCADA—Supervisory Control and Data Acquisition—systems[1] are a type of industrial control system[2] used to collect data and exercise control from a remote location. In the pipeline industry, SCADA systems are used to collect data from pipeline sensors[3] in real time and display these data to humans (controllers) who monitor the data from remote sites. Controllers, in turn, can use the SCADA system to input commands that remotely operate pipeline control equipment, such as valves and pumps. SCADA systems are widely in use in oil, gas, electricity, and municipal water systems.

Remote sensing of operational status was first used in the power industry in Chicago around 1912 when power companies used telephone lines to communicate power station status to a central office. The monitoring of the power lines was "supervisory" in that controllers monitored electric distribution for the city from a remote site and had station personnel execute changes to optimize electrical delivery.[4]

In the late 1960s, the term "SCADA systems" began to be used in the pipeline industry. For the current study, the National Transportation Safety Board asked pipeline operators when they first began using SCADA systems.[5] Nine control centers (slightly less than 10 percent) reported installing SCADA systems before 1970. These early SCADA systems were developed specifically for each company's needs and in most cases were developed by the company.

For pipeline applications, SCADA systems consist of a main control computer[6] connected via a communications link to field sensors (flow meters, pressure transmitters, temperature transmitters) and pipeline components (valves, pumps, control units). The

[1] As used in the energy sector, the expression "Supervisory Control and Data Acquisition" evolved from planning studies conducted by the Bonneville Power Administration in the 1960s. The Bonneville Power Administration is a Federal agency, under the U.S. Department of Energy, that markets wholesale electrical power and operates and markets transmission services in the Pacific Northwest.

[2] Distributed control is another industrial control system.

[3] The data from sensors are collected by remote computers or programmable logic controls and are then sent to the SCADA master computer.

[4] The history of SCADA was found in an article on "Telemetry" in *Encyclopedia Britannica*. Retrieved January 4, 2005, from http://www.britannica.com.

[5] More details about the Safety Board survey will be presented in later sections.

[6] Some systems have a distributed control system so that if the main control system fails, remote sites can control the whole system.

communications link can be made using leased telephone lines, satellite, microwave, radio circuits, or a variety of other methods.

The controller monitors data and controls the pipeline from a SCADA workstation. The interface between pipeline controller and the SCADA system consists of displays on computer monitors and input devices, such as keyboards and mice. Figure 1.1 shows a current interface for pipeline controllers using multiple computer screens arranged around the controller. The controller uses this interface to assess conditions on the pipeline and to operate the pipeline. The SCADA interface provides feedback to the controller of actions that happen at remote sites to ensure the controller remains aware of all conditions along the pipeline. Alarms are generated and displayed when field conditions are outside acceptable preset levels, when status changes occur, or when functions within the SCADA system generate an alarm.

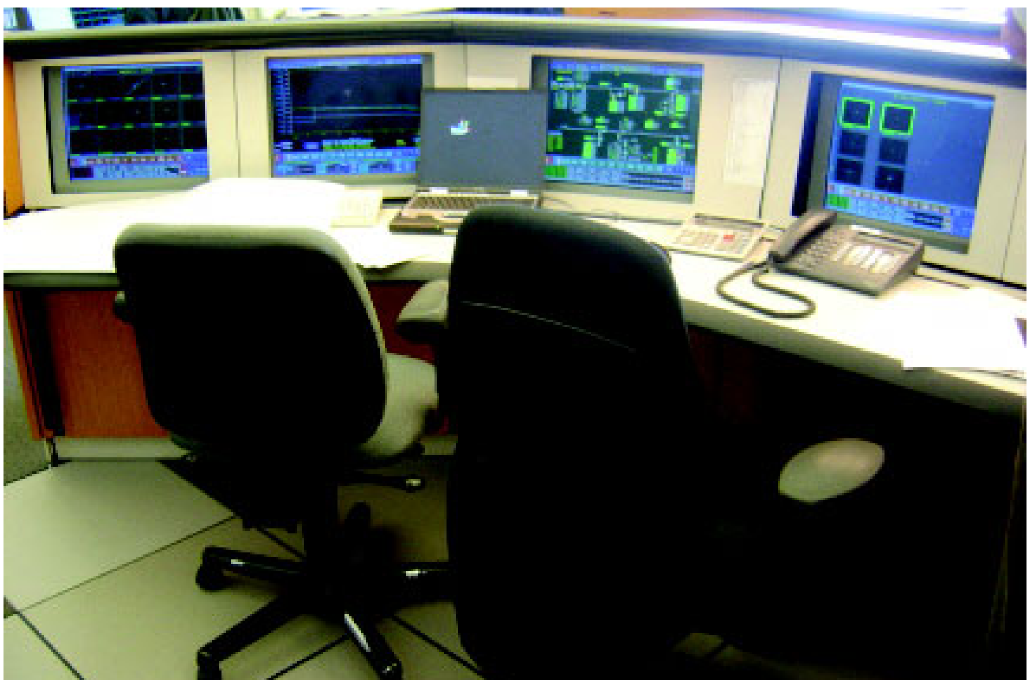

**Figure 1.1.** View of a SCADA workstation showing arrangement of screens and input keyboard.

Field data for a limited time frame (as long as 24 hours, depending on the company) are stored in an operationally active database. For most systems, selected portions of the historical data are archived to another medium, typically an optical disk or tape drive. Many systems also provide a supervisory/development computer platform for supervisor viewing of pipeline displays, training, and testing new software routines before implementing them in the SCADA computer.

Advances in technology have reduced the cost of SCADA systems, facilitating widespread SCADA implementation for pipeline control. Further, technological advances have increased the functionality of SCADA systems. Most systems, for example, have evolved from monochromatic tabular displays to multicolored graphical displays. SCADA developers are also adding more analytic tools to assist controllers in detecting possible leaks, monitoring specific products in the pipeline, and monitoring trends on the pipeline across time. Much of this development has occurred company-by-company due to the unique characteristics of each company's operating practices and other computer systems. For example, one company may use red to show an operating pump while another may use green. In 1993, recognizing the need for overall SCADA guidelines, the American Petroleum Institute[7] (API) developed a set of general guidelines for companies to consider in control room development.[8] These guidelines covered a wide range of topics, including general SCADA architecture, reliability, recovery, control room design, SCADA interface design, and data recording and training. A variety of trade publications and books also provides guidance to developers in configuring their SCADA systems. In addition, the SCADA vendor can also be a valuable source in the design of the system, having acquired knowledge from previous applications with other installations.

## Purpose and Methodology of the SCADA Study

In 2004, there were 141 accidents reported by hazardous liquid pipeline operators. These accidents resulted in 5 fatalities, 13 injuries, and over 130 million dollars in property damage. This study was designed to examine how pipeline companies use SCADA systems to monitor and record operating data and to evaluate the role of SCADA systems in leak detection. The number of hazardous liquid accidents investigated by the Safety Board in which leaks went undetected after indications of a leak on the SCADA interface was the impetus for this study. The study describes SCADA systems being used at pipeline companies that transport hazardous liquids and examines the extent to which the SCADA system design helps or hinders controllers in detecting leaks and acting to limit the amount of product released.

The Safety Board examined SCADA system information from companies varying in size and with SCADA systems varying in age. The use and design of SCADA display screens and SCADA alarms were examined in this study. The Board also examined the controllers' SCADA training and any decision aids that had been developed to assist controllers in handling abnormal operating conditions.

The study also considered the following: hazardous liquid pipeline accidents that the Safety Board has investigated since 1992, accidents that have appeared in the Office of Pipeline Safety's (OPS)[9] hazardous liquid pipeline accident database since 2002 (when

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[7] The American Petroleum Institute is a trade organization for oil companies and is involved in education, lobbying, and standards creation.

[8] *Developing a Pipeline Supervisory Control Center,* API Publication 1113 (2000).

[9] The Office of Pipeline Safety is an agency that resided within the old Research and Special Programs Administration. In 2005, the Office of Pipeline and Hazardous Materials Safety Administration was created to include the Office of Pipeline Safety.

that agency began collecting SCADA information on the hazardous liquid pipeline accident report form), information presented at the Board's Pipeline Safety Hearing in 2000,[10] and DOT Pipeline Safety Regulations. This background information is discussed in chapter 2. In addition, the Safety Board developed a survey to obtain general information on SCADA systems from hazardous liquid pipeline operators. The survey and survey responses are discussed in chapter 3. The Safety Board also visited 12 of the companies that responded to the survey to obtain more detailed information, as discussed in chapter 4. Finally, chapter 5 discusses the safety issues that were uncovered during the course of the study.

[10] The Safety Board held a Pipeline Safety Public Hearing on November 16-17, 2000, in Washington, DC.

# Chapter 2

# Background

## Accidents Involving SCADA

Pipelines represent a safe and economical way to transport petroleum, petroleum products, and other hazardous liquids. However, when pipeline accidents do occur, the human, economic, and environmental costs can be huge. Over the years, the Safety Board has investigated a number of accidents involving SCADA systems and issued its first related recommendation in the early 1970s.[11]

For this study, the Safety Board examined the role of SCADA systems in the 13 hazardous liquid line accidents that the Safety Board investigated from April 1992 to October 2004. In ten of these accidents, some aspect of the SCADA system contributed to the severity of the accident. In the other three, the SCADA system was not discussed as an issue in the Board's investigation.[12]

The Safety Board also considered a variety of related information that is discussed in this chapter, including OPS accident reports, testimony from the Board's 2002 Pipeline Safety Hearing, and regulatory information.

### *Brenham, Texas (April 7, 1992)*[13]

A controller was remotely controlling a pipeline that transported highly volatile liquid (HVL) into a salt-dome storage cavern. The cavern had overfilled and the escaping product ignited, resulting in 3 fatalities, 21 injuries, and $9 million damage. The Safety Board noted that the controller did not recognize the changing pressures in the storage station piping as an emergency because his training did not include recognizing emergencies in station piping. In addition, the Safety Board noted that, had the SCADA system provided a graphic display of historical operating data (which would have allowed the controller to see pressure and flow trends), the controller could have more easily recognized that the flow of HVL into the cavern was abnormal. The Safety Board concluded that the SCADA system did not display data from the storage station in a format that was easy for controllers to interpret, and recommended that the American Gas

[11] Over the past 30 years, the Safety Board has issued approximately 30 recommendations either directly or indirectly related to SCADA systems. Of these, 9 have been issued to OPS, 17 to specific companies, 3 to organizations representing pipeline companies, and 1 to the Federal Railroad Administration. A list of these recommendations is located in Appendix A.

[12] Brief narratives of these three accidents are found in Appendix B.

[13] National Transportation Safety Board, *Highly Volatile Release from Underground Storage Cavern and Explosion, Mapco Natural Gas Liquids, Inc. Brenham, Texas, April 7, 1992,* Pipeline Accident Report NTSB/PAR-93/01 (Washington, DC: NTSB, 1993).

Association (AGA) and API develop standards and guidelines for the design and use of graphic information display systems used by controllers to control pipeline systems.[14]

### *Gramercy, Louisiana (May 23, 1996)*[15]

While using a SCADA system to operate a 20-inch refined products pipeline, the controller received an alarm for high pump-case pressure at a refinery that supplied product to the pipeline. Almost immediately, two more SCADA alarms were received, one for the shutdown of pumping units at the refinery due to low suction pressure and the other for line imbalance.[16] The controller erroneously determined that the initial pump shutdown was caused by activity at the refinery, and that the withdrawal of product from the pipeline to river barges had previously caused the pressure to drop to the point that pumps shut down and the SCADA system alarmed. (Actually, the shutdown occurred about 2 minutes after the pipeline ruptured where an excavator had damaged it.) The controller continued to receive SCADA alarms and simultaneously acknowledged all of them without attending to the nature of each, based on his belief that the cause was the loading of barges. While reading the text of the line balance alarm, he did not notice that the line balance was negative, which potentially indicated a leak.

After discussing the automatic pump shutdowns with field personnel and confirming that barges were being loaded, and regardless of the report from refinery personnel that they were delivering insufficient product to cause the SCADA system to alarm, the controller concluded that the loading of barges had caused the alarms. With the concurrence of field personnel, the controller attempted to restart pumps, but they shut off again. About an hour after the rupture, the line balance software again alarmed, showing a negative line balance differential. This time, the controller saw the negative line balance alarm and immediately initiated emergency action. As a result of the controller's delay in recognizing the leak, pipeline valves were not closed, the ruptured section was not isolated until about 4.5 hours after the rupture, and the pipeline released 475,000 gallons of gasoline into nearby waterways.

The Safety Board determined that the operator's delay in recognizing the rupture, which delayed shutting down the pipeline and isolating the rupture, contributed to the severity of the accident. The Board recommended that the operator use recurrent training to emphasize the importance of evaluating all alarms and increase proficiency in interpreting alarms that might indicate a leak. The Board also recommended that the operator review alarm formats and frequencies.[17]

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[14] Safety Recommendations P-93-20 and P-93-22 are classified "Open—Acceptable Response."

[15] National Transportation Safety Board, *Release of Hazardous Liquid Near Gramercy, Louisiana, May 23, 1996*, Pipeline Accident Brief NTSB/PAB-98/01 (Washington, DC: NTSB, 1998).

[16] A line imbalance occurs when the measured amount of product being pumped into a pipeline does not equal the measured amount of product exiting the pipeline.

[17] Safety Recommendations P-98-22 and P-98-23 were classified "Closed—Acceptable Action" on April 28, 1999.

### *Fork Shoals, South Carolina (Reedy River: June 26, 1996)*[18]

A 36-inch fuel oil pipeline under a company-ordered pressure restriction due to known corrosion on the pipeline was being operated with a SCADA system. On the night of the accident, after several deliveries from the pipeline had ended, the controller was adjusting pumps on the line to reduce pressure when improper pump operation caused a pressure surge and the pipeline ruptured. The controller improperly started and stopped the pumps, and when he contacted the shift supervisor for assistance, the supervisor incorrectly determined that the loss of pump operation at a station was due to an electrical failure. The supervisor also concluded incorrectly that negative pressure readings from the SCADA system at that station were not valid because of the power failure. After the controller began shutting down the pipeline by stopping pumps, the supervisor told the controller to start additional pumps to reduce pipeline pressure, thereby pumping additional fuel oil from the ruptured pipeline.

The Safety Board noted in its report that the controller was not using the optimum SCADA screen for viewing short-term pressure changes, and that the supervisor incorrectly determined that the abnormal pressure data were due to a power outage at one of the pump stations. Neither the controller nor the supervisor followed written company procedures for shutting down a pipeline after a pump failure. The Board determined that although the controller had enough information both to prevent the rupture and to limit the release after the rupture, he had not been adequately trained. In addition, the Board noted that a change in the controller's schedule might have contributed to his decreased alertness or responsiveness. The Board recommended that the Research and Special Programs Administration (RSPA) and the pipeline operator assess the potential safety risks associated with rotating controller shifts, and that, to reduce the likelihood of accidents attributable to controller fatigue, RSPA establish industry guidelines for controller work schedules.[19]

### *Murfreesboro, Tennessee (November 5, 1996)*[20]

An 8-inch diesel pipeline was being operated using a SCADA system. After a block valve[21] was closed in preparation for a pigging operation, the pigging team decided to restart delivery of diesel before running the pig.[22] The controller did not reopen the block valve before resuming pumping and, contrary to company procedures, started pumps at three stations while the pipeline was blocked. Overpressure shutdown set points at one pump station were incorrectly set and therefore allowed the blocked pipeline to be

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[18] National Transportation Safety Board, *Pipeline Rupture and Release of Fuel Oil in the Reedy River at Fork Shoals, South Carolina,* Pipeline Accident Report NTSB/PAR-98/01 (Washington, DC: NTSB, 1998).

[19] Safety Recommendation P-98-32 is classified "Closed—Acceptable Action." It will be discussed in chapter 5.

[20] National Transportation Safety Board, *Hazardous Liquid Petroleum Products Overpressure Rupture, Murfreesboro, Tennessee, November 5, 1996*, Pipeline Accident Brief NTSB/PAB-99/03 (Washington, DC: NTSB, 1999).

[21] A block valve is used to isolate a section of the pipeline, preventing flow through the valves.

[22] A "pig" is a mechanical device inserted into the pipeline to clean the line, ensure that there are no line blockages, or test the integrity of the pipeline.

over-pressured before the pumps shut down. Because the pressure transmitter at the block valve was incorrectly illustrated on the SCADA schematic, the controller was not aware that the pipeline pressure was increasing upstream of the closed valve. Within about 16 minutes of starting the pumps, the controller tried to open the block valve, but high differential pressure across the valve prevented it from opening.

Although company procedures required controllers to shut down blocked pipelines immediately, the controller instead tried two more times to open the valve. He then shut down pumps at two stations and increased a delivery from the pipeline in an attempt to lower the pressure. The valve finally opened on the controller's fourth attempt (20 minutes after originally starting up the pipeline), but unknown to the controller, the pipeline had ruptured minutes earlier. The controller then restarted pumps at two stations and pumped diesel out of the failed pipeline for about an hour after the rupture. When pipeline pressure did not increase as expected, the controller shut the pipeline down. Although the SCADA system registered a sudden pressure drop of 416 pounds per square inch (psi) at the time of the rupture, no SCADA alarm was generated.

After the accident, the operator purchased a SCADA simulator and revised its training program to better prepare controllers to respond to abnormal and emergency conditions. The pressure transmitter location was changed, overpressure protection set points were corrected, and SCADA schematic displays were reviewed and updated.

The Safety Board determined that the probable cause of the accident was the controller's failure to follow company procedures for operating the pipeline, and the inability of the SCADA system to inform the operator of the unsafe conditions prior to the pipeline rupture. Contributing to the severity of the accident was the controller's delay in recognizing that a leak had occurred, which delayed shutting down the pipeline and isolating the rupture.

### *Knoxville, Tennessee (February 9, 1999)*[23]

An operator was using a SCADA system to operate a 10-inch diesel pipeline. After completing a diesel delivery, the controller closed the valves and the pipeline was isolated and remained pressurized at 91 psi. Pressure strip charts were displayed for the previous hour across the top of the operating console of the SCADA display. The SCADA system recorded but did not alarm a sudden drop in pipeline pressure of 19 psi. The controller did not notice the pressure drop, which occurred when the pipeline ruptured and released approximately 53,550 gallons of diesel. The controller started another delivery using the same pipeline, and noticed that a meter indicated a no-flow rate and that pressures did not rise as expected. He consulted with a senior controller who decided to terminate the delivery. The controller calculated an abnormally high product shortage in the pipeline. According to the operator's procedures, a sudden loss of pressure and/or a

[23] National Transportation Safety Board, *Hazardous Liquid Petroleum Products Pipeline Rupture, Colonial Pipeline Company, Knoxville, Tennessee, February 9, 1999,* Pipeline Accident Brief NTSB/PAB-01/01 (Washington, DC: NTSB, 2001).

change in flow rate were to be interpreted as conclusive evidence of a leak, and controllers were to immediately investigate and correct any shortage calculation.

After reports from the field that no product leaks were observed, the controller (without consulting the senior controller) restarted the pipeline while the field employee observed at the terminal delivery point. Pipeline pressure did not rise as it normally would and lower flows than expected were observed at the delivery point. After a fire department reported a leak to the operator, the senior controller again ordered the pipeline shut down. This occurred about 4.5 hours after the rupture.

The Safety Board determined that contributing to the severity of the accident was the controller's failure to determine from the SCADA system that a leak had occurred, with the result that the controller started and restarted the pipeline, thereby increasing the amount of diesel that was released. The operator, on its own initiative, added this scenario to its SCADA simulator program and instituted a procedure for controllers to seek approval before restarting a pipeline that had been shut down for abnormal conditions.

### *Bellingham, Washington (June 10, 1999)*[24]

A controller was operating a 16-inch gasoline pipeline using a SCADA system with two SCADA computers: a primary and a backup. As the system administrator added historical records to the on-line primary computer, the computer system began to generate errors that seriously affected the performance of the SCADA system, causing it to be unresponsive to commands from the controller. As a result, when the controller attempted to adjust pumps on the pipeline to reduce pressure buildup associated with a change in delivery locations, the controller did not have full control of the pipeline. (The pressure buildup was occurring in a section of pipeline that had been damaged by an excavator). After switching control between the primary and backup computer several times, the controller shut down the pipeline, unaware that it had ruptured. Once the system was operational, the controller then restarted the pipeline and operated it until receiving an alert from the computational pipeline monitoring software (CPM).[25] At about the same time, he received a report about a gasoline smell. The controller then shut down the pipeline. As a result, block valves were not closed until 1 hour 5 minutes after the rupture, and 237,000 gallons of gasoline were released and ignited. The fire caused three fatalities and eight injuries.

The Safety Board concluded that, had the SCADA system computers remained responsive to the commands of the controllers, the controller could have initiated actions that would have prevented the pressure increase that ruptured the pipeline. The Board concluded further that the degraded SCADA performance experienced by the controllers likely resulted from database development work being performed on the online SCADA

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[24] National Transportation Safety Board, *Pipeline Rupture and Release of Gasoline, Olympic Pipeline Company, Bellingham, Washington, June 10, 1999*, Pipeline Accident Report PAR-02/02 (Washington, DC: NTSB, 2002).

[25] Computational pipeline monitoring is a software-based monitoring tool that alerts a pipeline controller of a possible anomaly that may indicate a commodity release.

system. The Safety Board recommended that RSPA issue an advisory bulletin regarding the need to use an off-line system to perform SCADA database development work, modifications, and testing.[26]

### *Winchester, Kentucky (January 27, 2000)*[27]

An operator was using a SCADA system to operate a 24-inch crude oil pipeline. The pipeline had been out of service for maintenance work at a nearby terminal. About 16 minutes after the controller opened valves to begin operating the pipeline, a CPM alarm displayed. The controller started additional pumping units, and the system indicated that the alarm had cleared and the flow rates were in balance. About 30 minutes after the first CPM alarm, another CPM alarm indicated a flow imbalance, but the controller attributed the cause of this alarm to conditions associated with the startup of the pipeline. Twelve minutes after this alarm (immediately after the pipeline had ruptured at a dent in the pipe), another CPM alarm displayed. Within 25 minutes, the controller started to shut the pipeline system down, but after discussing the situation with a shift supervisor and field supervisor, agreed to continue pumping product and monitor the pressure.

The pipeline pressure did not increase as expected and more CPM alarms were received. After again conferring with field personnel, the controller's supervisor told the controller to shut down the pipeline. This was accomplished about 1.75 hours after receipt of the first CPM alarm associated with the rupture. Within about 15 minutes of this shutdown, remotely operated valves were closed, and within about 1.5 hours of the shutdown, manual valves were closed. In the meantime, about 489,000 gallons of oil were released in a golf course and creek.

The Safety Board determined that the failure of the controller and supervisor to recognize the rupture in a timely fashion, shut down the pipeline, and isolate the ruptured section contributed to the severity of the accident. After the accident, the operator hired a training supervisor and began training controllers using a SCADA simulator to improve their ability to recognize and react to problems.

### *Greenville, Texas (March 9, 2000)*[28]

A controller was using a SCADA system to operate a 28-inch gasoline pipeline when the pipe ruptured at a crack. Shortly after the rupture, a pump station upstream of the failure location automatically shut down. The controller started a different pump at the same station to keep the pipeline operating while field personnel investigated the initial shutdown of pumps. Within 2 minutes of being started, the second pump automatically shut down. The controller then shut down the entire pipeline. Believing the cause of the

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[26] This recommendation (P-02-5) was classified "Closed—Acceptable Action" on March 3, 2004.

[27] National Transportation Safety Board, *Hazardous Liquid Pipe Failure and Leak, Marathon Ashland Pipe Line, LLC Winchester, Kentucky, January 27, 2000,* Pipeline Accident Brief NTSB/PAB-01/02 (Washington, DC: NTSB, 2001).

[28] National Transportation Safety Board, *Hazardous Liquid Pipe Failure and Leak, Explorer Pipeline Company, Greenville, Texas, March 9, 2000*, Pipeline Accident Brief NTSB/PAB-01/03 (Washington, DC: NTSB, 2001).

initial shutdown had been a control valve problem, the controller restarted the pipeline at a reduced flow rate several minutes later and operated it for about 13 minutes before again shutting it down for evaluation. The controller shut down the pipeline about 29 minutes after the failure, and within 39 minutes of the rupture, closed the remotely operated valves to isolate the ruptured section. The pipeline released about 564,000 gallons of gasoline. After the accident, RSPA required the operator to submit a plan before returning the line to operation. The operator's plan for restarting the pipeline called for an incident review that addressed controller training and SCADA design improvements, including simulator training for controllers.

### *Chalk Point, Maryland (April 7, 2000)*[29]

A 12-inch fuel oil pipeline was being cleaned with no. 2 oil to propel cleaning and sizing pigs through the pipeline in preparation for an in-line inspection. The cleaning procedure used a reverse flow operation. The existing pipeline monitoring system was not capable of monitoring pipeline operating conditions because of the locations of meters and sensing points. To account for the oil volume, determine the flow rate, and estimate the time the pigs would arrive, field personnel at both ends of the pipeline made periodic storage tank level measurements and manually converted these measurements to volumes. Only after the pigs did not arrive as expected and a pump began cavitating[30] did operators suspect a problem. During the pigging operation, the pipeline ruptured at a buckle in the pipe but remained in operation for about 7 hours after the rupture occurred.

Approximately 140,400 gallons of fuel oil were released and the environmental response and cleanup cost was $71 million. The Safety Board concluded that lack of adequate pipeline monitoring practices and procedures delayed discovery of the leak. After the accident, OPS required the pipeline owner to install an improved SCADA system with software-based leak detection and radar tank gauges.

### *Kingman, Kansas (October 27, 2004)*[31]

A controller was using a SCADA system to operate an 8-inch anhydrous ammonia pipeline when the pipe ruptured in a section weakened by previous excavation damage. The controller received numerous low-pressure, pressure rate-of-change, and pump shutdown alarms within 5 minutes of the rupture. The controller erroneously determined that these alarms were caused by excessive delivery of ammonia from the pipeline, and waited for the pressures to return to normal. When they did not, approximately 12 minutes after the rupture had occurred, the controller operated a control valve to increase the rate of ammonia flowing into the pipeline. About 33 minutes after the rupture, and before the controller had taken any action to shut down the pipeline, the control center

[29] National Transportation Safety Board, *Pipeline Accident Report: Rupture of Piney Point Oil Pipeline and Release of Fuel Oil Near Chalk Point, Maryland, April 7, 2000*, Pipeline Accident Report NTSB/PAR-02/01 (Washington, DC: NTSB, 2002).

[30] Cavitation means that bubbles are forming in the liquid being pumped. Cavitation can damage pumps and reduce efficiency.

[31] The Safety Board is currently investigating this accident and has not released the report.

received a phone call reporting the leak, prompting the controller to shut down the line. The pipeline released about 204,000 gallons of anhydrous ammonia. The controller did not use available SCADA trend screens to review and evaluate the alarms and abnormal conditions.

### *Accidents Summary*

The principle issue in the SCADA-related accidents investigated by the Safety Board was the delay in a controller's recognizing a leak and beginning efforts to reduce the effect of the leak. SCADA factors identified in these accidents include alarms, display formats, the accuracy of SCADA screens, the controller's ability to accurately evaluate SCADA data during abnormal operating conditions, the appropriateness of controller actions, the ability of the controller and the supervisor to make appropriate decisions, and the effectiveness of training in preparing controllers to interpret the SCADA system and react to abnormal conditions.

Most the issues just listed are the result of controllers not understanding information presented by the SCADA system. Table 2.1 summarizes the accidents discussed above. In the four systems for which leak detection software was in place, the systems detected the leaks. Two cases involved members of the public notifying the operator of the leak. The controllers who detected the leaks responded to pumps shutting down or a failure of pressure to increase when pumps were started. The SCADA issue identified most often in these accident reports was training. In six of the accidents, controllers sought assistance from other controllers, supervisors, and/or field personnel to make decisions about shutting down the line. Finally, in six of the accidents, the pipeline was stopped and then restarted after the leak occurred.

**Table 2.1. Summary of liquid pipeline accidents with SCADA issues.**

| Accident Site | Initial Method of Detection | SCADA Issues Involved in Accident | Team Decision on Leak | Did Controller Restart Pipeline? |
|---|---|---|---|---|
| **Brenham** | LDS (vapor sensor) | Graphics, training | No | No |
| **Gramercy** | LDS | Alarms, training | Yes | Yes |
| **Fork Shoals** | Controller | Training, fatigue, alarms | Yes | Yes |
| **Murfreesboro** | Controller | Schematic accuracy, training | No | No |
| **Knoxville** | Public | Training | Yes | Yes |
| **Bellingham** | LDS, company field personnel | SCADA system failure | Yes | Yes |
| **Winchester** | LDS | Training | Yes | Yes |
| **Greenville** | Controller | Training | No | Yes |
| **Chalk Point** | Company operating personnel | Procedures | Yes | No |
| **Kingman** | Public | Alarms, training | No | No |

## Pipeline Accidents Since 2002

In 2002, OPS redesigned its accident report form and, for the first time, requested information on the use of LDS and the methods initially used to detect pipeline leaks.[32] OPS changed the accident form in response to a Safety Board recommendation made in its Special Investigative Report, *Evaluation of Accident Data and Federal Oversight of Petroleum Product Pipelines.*[33] The recommendation asked RSPA (and therefore, OPS) to improve its data collection by obtaining data that could assist in accident trend analyses and evaluations of pipeline operator performance using normalized accident data.[34] The revised accident report form includes two items that relate to SCADA systems. It asks the reporting pipeline company about the presence of computer-based leak detection capability on the affected pipeline and how the leak was initially detected. See table 2.2.

For the 3-year period from January 1, 2002, through December 31, 2004, OPS received 1,172 hazardous liquid pipeline accident reports on the new form. Of these, 339 met the OPS criteria that required inclusion of information about leak detection, which included SCADA information.[35] These accidents resulted in company-reported property losses of over $57 million and the loss of over 7 million gallons of hazardous liquids. The primary company-reported causes of spills were corrosion (96), excavation damage (38), malfunction of control/relief equipment (33), and incorrect operation (23).

Of the 339 accidents meeting the criteria, 45 percent were detected by local operating personnel, procedures, or equipment, and 27 percent were detected by a third party (for example, an excavator or homeowner). CPM/SCADA leak detection detected 8 percent of the leaks and remote-operating personnel, including controllers, detected 9 percent of the leaks. Table 2.2 lists all the detection methods identified in the accident reports.

[32] A copy of the revised accident report form is shown in appendix C.

[33] National Transportation Safety Board, *Evaluation of Accident Data and Federal Oversight of Petroleum Product Pipelines,* Pipeline Special Investigation Report NTSB/SIR-96/02 (Washington, DC: NTSB, 1996).

[34] Safety Recommendation P-96-1 was classified "Closed—Acceptable Action," as a result of the new data form. The Safety Board issued the recommendation based on the difficulty the Safety Board encountered in interpreting data collected on the old accident reporting form. From 1986-1994, the second-leading cause for pipeline accidents was "other." Even for the number-one cause, "external damage," there was no way to determine if the external damage was excavation without reading the narrative of the accident. Finally, for external corrosion accidents, no data were collected about types of coatings or cathodic protection systems, damage to coatings, or exposure conditions that would enable RSPA to analyze the causes for external corrosion failures.

[35] The remaining 833 accident reports addressed small spills of at least 5 gallons but less than 5 barrels and thus contained no information about leak detection. (A barrel is 42 U.S. gallons.) The accident reporting form that was introduced in 2002 required operators to report spills of less than 5 barrels, but only limited information was required.

| Table 2.2. Methods of initial detection of leak (from OPS accident report form). | |
|---|---|
| Local operating personnel, procedures, or equipment | 152 |
| A third party (for example, excavator or homeowner) | 91 |
| Remote operating personnel, including controllers | 29 |
| CPM/SCADA-based system with leak detection | 26 |
| Air patrol or ground surveillance | 25 |
| Other | 9 |
| Blank (not answered by company) | 5 |
| Static shut-in-test or other pressure or leak test | 2 |
| Total | 339 |

Although the detection of leaks by remote operating personnel (including controllers) or SCADA systems with LDS accounted for only 17 percent of all leaks detected, these leaks accounted for company-reported product losses exceeding 4 million gallons and nearly 60 percent of the losses for all spills over 5 barrels.[36] (See figure 2.1.) It is worth noting that the average reported product loss in spills initially detected by CPM/SCADA was 72,600 gallons in contrast to the mean leak initially detected by controllers, which was 82,800 gallons.

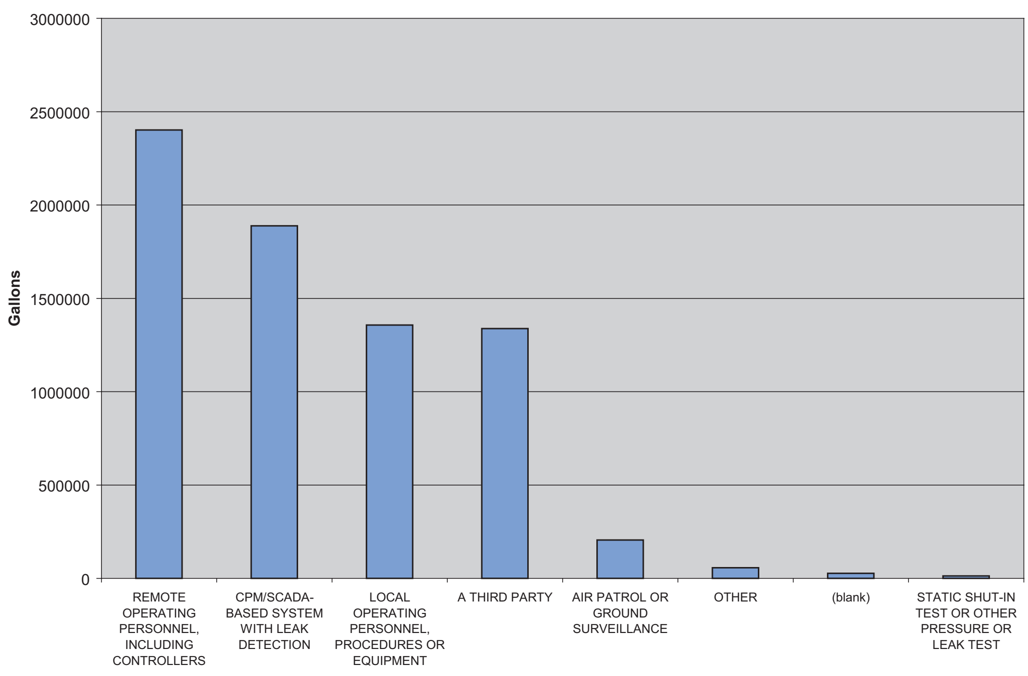


**Figure 2.1.** Total product lost in gallons by method of initial leak detection.

[36] Over 7 million gallons of hazardous liquids were released over the 3-year period in spills over 42 gallons.

In addition, spills detected by a CPM/SCADA-based leak detection system or remote operating personnel including controllers had a longer duration than spills detected by other detection methods. The average duration of pipeline leaks over 5 barrels was 30 hours, whatever the method. Spills detected with CPM/SCADA had a duration that averaged 19 hours and spills detected by controllers averaged 10 hours (figure 2.2). Slightly over half of the accidents reported occurred in systems with CPM monitoring.

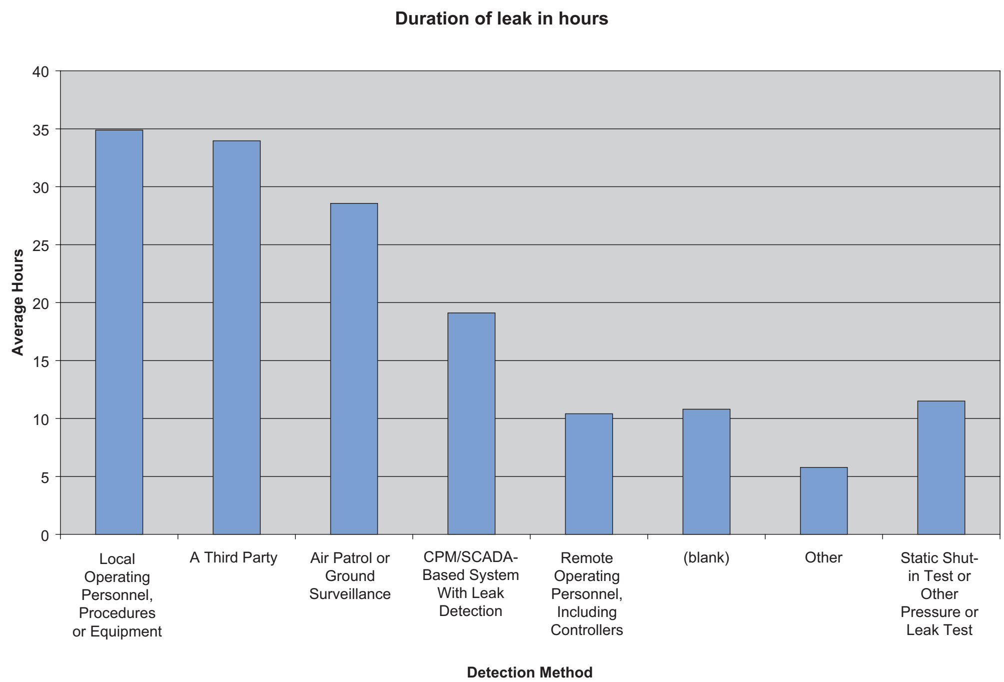


**Figure 2.2.** Average duration of leaks by method of leak detection from OPS accident dataset.

In addition to compiling the data described above, the Safety Board examined the role of SCADA systems in either mitigating or exacerbating leaks that had occurred. The Board reviewed the narrative portion of the OPS accident reporting form for 604 accidents and found 10 that mentioned SCADA. In seven of these cases, the SCADA system had displayed indications of abnormal operating conditions, and the line was shut down. In two cases, the SCADA system was used to investigate the release, and in the last case, a SCADA sump alarm failed to activate; thus, there was no indication of a sump failure on the controller's SCADA screens. In another report, which mentioned CPM alarms but did not mention SCADA, the CPM alarms sounded and the pipeline was shut down. The lack of information about SCADA systems in the narratives prevents any conclusions about the role of SCADA in leak occurrences based on this database.

## Pipeline Safety Hearing

On November 15 and 16, 2000,[37] the Safety Board held a 2-day hearing on pipeline safety. This hearing was prompted by Board investigations of numerous pipeline accidents in which pipe with time-dependent defects had failed, as well as numerous accidents investigated in the late 1990s that involved the lack of timely recognition of pipeline ruptures and associated timely action to reduce the consequences of the spill.

The hearing examined technologies available to assess the integrity of pipelines, including internal inspection tools and the pipeline operating systems that identify leaks and prompt controllers to take timely response actions. Representatives from selected manufacturers, operators, and OPS testified on the integrity management of pipelines, leak detection systems, and operator response. Specific testimony addressed SCADA systems, alarms, and simulator systems, as summarized below.[38]

### *SCADA Systems*

Speakers emphasized the controllers' central role in the development of any SCADA system. According to the OPS representative, "a well-trained and vigilant controller will always play a critical role in leak avoidance and leak detection," and noted that pipeline control should start with the controller and a SCADA system that is designed to fit the controller's needs.

Even in SCADA systems with leak detection capabilities, the leak detection task still falls to the controller who must assess the credibility of a leak alarm. In several of the Safety Board accident examples discussed at the hearing, controllers had not understood leak information presented by SCADA systems. These cases resulted in delayed response to leaks and, as a result, greater product loss.

Another point covered by speakers was the lack of specific standards for implementing SCADA systems. The OPS representative reported that although they do not mention SCADA systems, the regulations are written for operational safety. He stated further that, if the SCADA system is being used to comply with these safety requirements, OPS has the authority to inspect the SCADA system, even though the term "SCADA" does not appear anywhere in the Federal Pipeline Safety Standards.

### *Alarms*

The alarms discussion focused primarily on the effects of false alarms on controllers. "When [alarms] occur, and the operators see them day after day after day, they tend to get desensitized to certain kinds of alarms." One speaker noted the following:

[37] For more information, see http://www.ntsb.gov/events/2000/pipeline_hearing/.

[38] Presentations were made by Office of Pipeline Safety, Neles Automation, Stoner Associates, Simulutions, EFA Technologies, Inc., Tyco International, UTSI International Corporation, Senftleber and Associates, Alyeska Pipeline Service Company, Marathon Ashland Pipe Line LLC, and the American Petroleum Institute Cybernetics Subcommittee.

> It's not to say that in some cases, those frequent alarms aren't meaningful and shouldn't be acted upon, but I think when you combine the fatigue, familiarity with the system, and maybe … desensitization, things tend to get missed, and they tend not to believe them when they see them until they are seeing them repetitively.

Alarms indicating a potential leak present controllers with a dangerous dilemma: stop the line for what may be a false alarm or continue operating with a possible leak. One speaker noted that false alarms or nuisance alarms are perhaps a bigger problem than everyone admits.

Discussion also focused on the use of SCADA-recorded alarms in the historical database as a possible way to remedy the problem of false alarms. Several companies reported examining alarms in their historical data and adjusting alarm parameters in an effort to limit the number of alarms that occur but add little to controllers' information needs.

### *Simulators*

Many speakers emphasized the value of training simulators in preparing controllers to use SCADA systems effectively. For example, testimony indicated that full-scale training simulators, which use current modeling technology coupled with a virtual control system, allow companies to introduce controllers to scenarios that extend beyond those of day-to-day pipeline operations. Further, according to witnesses, the scenarios created with simulators can be tested and retested to ensure that they are accurate.

Both manufacturers and pipeline companies noted the improved quality of current simulators. They noted that, since the first simulators came into use about two decades ago, their fidelity has improved so much that controllers might have difficultly differentiating simulated data from actual data. Speakers stated that the complexity of simulators can vary from small, partial-task simulators on a single computer[39] to full replicas of the SCADA console with simulated data. Partial simulators can be useful in teaching controllers one aspect of the job, such as hydraulics or leak detection, and full simulators can be helpful in teaching how to recognize and respond to leaks. However, to be successful in helping controllers recognize leaks, speakers indicated that simulators must be used regularly due to the rarity of possible leaks. One company reported that, to pass its training, controllers were required to exhibit adequate performance on the simulator.

Another company reported using its simulator as part of its WIGO process of evaluating alarms. WIGO ("what is going on?") is a tool that controllers can use to accurately evaluate the cause of the alarm and take action. In its training on the use of the WIGO decision-making tool, this company introduced problem-solving techniques and tools, emphasized the importance of effective teamwork in decision-making, and communicated company expectations relating to abnormal situations presented on the simulator.

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[39] A partial-task simulator does not attempt to simulate all the functions of the SCADA system but focuses instead on subsystems or parts.

## SCADA and the DOT Pipeline Safety Regulations

### *Safety Regulations*

The safety regulations for hazardous liquid pipelines [49 *Code of Federal Regulations* (CFR) 195] do not directly require the use of SCADA technology for any aspect of pipeline operations. However, most pipeline operators have installed SCADA technology and use it not only to improve the efficiency and safety of their pipeline operations but also to comply with certain safety regulation requirements, such as communications; maintenance of safety devices, maps, and records; and Computational Pipeline Monitoring (CPM)[40] methods of leak detection. To the extent that an operator uses a SCADA system to comply with a regulatory requirement, the system is subject to regulations and OPS jurisdiction.

To assist in enforcing the regulations related to an operator's SCADA system, OPS developed *SCADA Worksheets* as attachments to its inspection forms: *Standard Inspection Report of a Liquid Pipeline Carrier* and *Standard Inspection Report of a Gas Transmission Pipeline*. The forms advise that a more thorough SCADA evaluation may be warranted based on the results of the worksheet or other events (such as an accident). The forms also identify sections of the regulations associated with the operator's SCADA system for use by OPS inspectors.

For example, the safety regulations require that operators maintain records of pump station discharge pressures, which may be derived from the SCADA system. The *SCADA Liquid Worksheet* attachment to the *Standard Inspection Report of a Liquid Pipeline Carrier* identifies the code section for this requirement and suggests several areas for the inspector to question the operator. Pipeline operators are required to maintain current maps and records of their pipeline systems, and because this requirement includes pipeline and equipment configurations illustrated on various SCADA screens, the *SCADA Liquid Worksheet* identifies the code section for the maps and records requirements and suggests several areas for the inspector to question the operator. Likewise, pipeline operators are required to have a communication system that transmits the information needed to operate the pipeline system safely.

On July 6, 1998, OPS promulgated regulations regarding leak detection on hazardous liquid pipelines that became effective July 6, 1999 (49 CFR 195.134 and .444). The regulations do not require the use of any particular system for any aspect of pipeline operations, or that CPM[41] leak detection systems be installed on hazardous liquid pipelines. However, these regulations do require that existing CPM leak detection systems on hazardous liquid pipelines transporting liquid in a single phase[42] comply with

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[40] If a CPM system is installed, it must follow the OPS regulations regarding CPM systems (49 CFR Part 195.3 (c)(2)(ii)).

[41] The CPM system may be embedded in the SCADA system or the CPM system may be a standalone program that gathers data from the SCADA system and sends computed data or alarms to the controller interface.

[42] Single-phase products do not contain gaseous product with the liquid product.

the operating, maintenance, testing, record-keeping, and dispatcher training requirements of API 1130 (*Computational Pipeline Monitoring for Liquid Pipelines*).[43] In addition, the design of each new CPM leak detection system and each replaced component of an existing CPM leak detection system are required to comply with section 4.2 of API 1130 and with any other design criteria addressed in API 1130 for components of the CPM leak detection system. API 1130 advises operators about the installation and operation of CPM leak detection systems. Compliance with API 1130 is established during an OPS inspection.

In 2001 and 2002, OPS promulgated regulations for pipeline integrity management for hazardous liquid pipelines (49 CFR 195.452). These regulations apply only to hazardous liquid pipelines that are either located in a high consequence area or could affect a high consequence area.[44] The regulations do not require the use of SCADA technology for any aspect of pipeline operations. However, operators are required to conduct a risk analysis to identify the need for additional measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area, and are required to have a means to detect leaks in their pipeline systems. The leak detection capability must be evaluated using the results of the risk analysis and other factors listed in the regulations, and operators are required to determine if modifications to their leak detection capabilities are needed to improve their ability to respond to a pipeline failure and protect high consequence areas. Operators can implement a CPM leak detection system to upgrade their leak detection capabilities.

### *Advisory Bulletins*

On July 16, 1999, Advisory Bulletin ADB 99-03 was published in the *Federal Register*. Developed as a result of the initial OPS investigation of the Bellingham, Washington, pipeline accident, OPS used ADB 99-03 to inform pipeline system owners and operators of potential operational limitations associated with SCADA systems and the possibility that those limitations could lead to or aggravate pipeline releases. The bulletin recommended that pipeline operators accomplish the following: review the capacity of their SCADA systems to ensure that the systems had resources to accommodate normal and abnormal operations; review SCADA configuration and operating parameters to ensure that SCADA computers were functioning as intended; and ensure that system modifications did not adversely affect overall performance of the SCADA system.

On December 23, 2003, Advisory Bulletin ADB 03-09 was published in the *Federal Register*, in response to Safety Recommendation P-02-5, which was issued as a result of the Bellingham, Washington, pipeline accident. This recommendation asked RSPA to inform pipeline owners and operators of the potential for service disruptions in SCADA systems caused by maintenance or enhancements of SCADA systems and other critical databases and the possibility of those disruptions leading to or aggravating pipeline

[43] *Computational Pipeline Monitoring for Liquid Pipelines* (Second Edition), API Standard 1130 (American Petroleum Institute, 2002).

[44] High consequence areas are defined as urban areas and other populated places as designated by the U.S. Census Bureau, commercially navigable waterways, or drinking water and ecological resources that are unusually sensitive to a pipeline failure.

releases. As a result of RSPA actions, the Safety Board classified the recommendation "Closed—Acceptable Action." The bulletin also advised pipeline owners and operators to review their procedures for upgrading, configuring, maintaining, and enhancing their SCADA systems. The bulletin also stated that a good practice for pipeline owners and operators was to periodically review their SCADA system configurations, operating procedures, and performance measurements to ensure that SCADA computer servers functioned as intended. Pipeline owners and operators were advised to consider using offline or development workstations/servers to help ensure that impending changes are tested as thoroughly as possible before moving the changes into production.

The *SCADA Worksheet* attachments to the OPS inspection forms instruct the inspector to review ADB 99-03 and ADB 03-09 with the pipeline operator. However, these documents are advisory only and not part of the regulations.

### *Operator Qualification*

On August 27, 1999, in response to mandates in the *Accountable Pipeline Safety and Partnership Act of 1996,* and recommendations from the Safety Board,[45] OPS promulgated regulations, effective October 26, 1999, regarding qualification of pipeline operators (49 CFR 192 Subpart N and 49 CFR 195 Subpart G). The regulations require pipeline operators to prepare a written qualification program and establish qualification requirements for controllers in performing covered tasks[46] and in recognizing and reacting to abnormal operating conditions that might occur while performing covered tasks.

Because some of the tasks performed by pipeline controllers meet the definition of a covered task, these regulations apply to pipeline controllers. An example of a covered task performed by a controller is remote operation of a hazardous liquid pipeline, including monitoring operating parameters, making notifications, monitoring for pipeline leaks, remotely adjusting and maintaining pressure and flow, remotely starting and stopping pumps, and recognizing and reacting to abnormal conditions.

On March 3, 2005, in response to mandates in the *Pipeline Safety Improvement Act of 2002,* OPS promulgated additional regulations regarding qualification of pipeline operators that became effective July 1, 2005. These regulations restrict operators from using observation of on-the-job performance as the sole method of evaluation, and require operators to provide training, as appropriate, to ensure that individuals performing covered tasks have the knowledge and skills necessary to perform those tasks.

[45] Safety Recommendation P-87-2 asked RSPA to require that operators of pipelines develop and conduct selection, training, and testing programs to qualify controllers annually. The recommendation was closed, unacceptable action on July 27, 1998. Safety Recommendation P-97-7 asked RSPA to complete a final rule on employee qualification training and testing standards within 1 year, to require operators to test employees on the safety procedures they are expected to follow, and to require employees to demonstrate that they can correctly perform the work. This recommendation was also closed, unacceptable action, on April 18, 2001.

[46] Defined in the OPS regulations as an activity, identified by the operator, that is performed on a pipeline facility; is an operations or maintenance task; is performed as a requirement of this part; and affects the operation or integrity of the pipeline.

### *Controller Certification Pilot Program*

In compliance with the *Pipeline Safety Improvement Act of 2002*, which directed the Secretary of Transportation to develop tests and other requirements for certifying individuals who operate computer-based systems for controlling the operation of pipelines, OPS initiated a study of controller certification in 2004. In this regard, OPS is conducting a pilot program to determine the best combination of prescriptive and performance-based requirements for certifying pipeline controllers. OPS plans to submit a report to Congress by December 2006, as required by Congress, on the results of the pilot program, including recommendations on the possible certification of pipeline controllers.

As part of this effort, an OPS project team is evaluating current operator personnel qualification practices for pipeline controllers. OPS's experience, supplemented by consultation with a specifically assembled focus group, and a variety of operator interviews conducted at the beginning of this project, all showed that qualification practices for controllers among pipeline operators vary greatly.

A notice was published in the April 15, 2005, *Federal Register* regarding the Controller Certification Pilot Program, to be conducted from the second quarter of 2005 through the first quarter of 2006. The notice solicited three participants for the pilot program and provided information about the certification study project. During the pilot program period, OPS will monitor and evaluate programs of the selected pilot operators to determine the value that specific practices add to an adequate qualification program, and possibly a certification process. OPS determined that the pilot program will emphasize gas transmission and hazardous liquid pipelines and noted that additional operators of all types will be contacted informally to provide supplemental information on practices, processes, procedures, and standards that are used, or could be used, to demonstrate controller expertise. The project will identify actions OPS should recommend for additional assurance that individuals who operate computer-based systems for controlling pipeline operations are adequately qualified and, if deemed necessary, certified to perform their job responsibilities. The project will determine whether current regulations are sufficient to address the findings resulting from a review of Safety Board accident reports[47] and other project development activities, or whether regulations must be enhanced to provide additional controller qualification requirements. The project will also determine whether a certification process for controllers is warranted.

[47] OPS reviewed recent Safety Board pipeline accident reports and determined that in 10 of the 18 investigations reviewed, controller actions or reactions, or the computer systems they used, were identified as significant factors in detecting or contributing to the initial event, influencing reaction time, or affecting the magnitude of an event.

# Chapter 3

# SCADA Survey and Results

## Survey Development

The first phase of this study was the survey, which was used to obtain data about the liquid pipeline industry's use of SCADA systems. The Safety Board developed the survey with input from industry. The survey[48] covered basic information about the pipeline company and its SCADA system. Pipeline questions addressed the size of the pipeline system and the commodities it carried. SCADA questions addressed the history of SCADA in that control center, the basic architecture of the current SCADA system and its capabilities, changes made or planned to the system, methods of leak detection used on the pipeline, and communications, training, and oversight. Before distribution, the draft survey was circulated for comment to members of the API's Cybernetics Committee and the Office of Pipeline Safety.

The survey was mailed in July of 2003 to 96 liquid pipeline control centers using the selection criteria described in the next section. The survey was voluntary, and individual company responses were confidential. The seven companies that reported not having a SCADA system were asked to complete only the first 8 items of the 67-item survey.

### *Company Selection Method*

The Safety Board selected liquid pipeline companies that were required to pay user fees to OPS. At the time of the selection, RSPA/OPS was collecting user fees from 169 pipeline companies. The Board called each company to identify the control center that operated the pipeline and identified 96.[49] The survey was mailed or e-mailed to these control centers, beginning July 14, 2003. Companies that did not return the survey were called about every 6 weeks for follow-up.

## Survey Results[50]

Of the 96 companies that initially received the Safety Board's letter about the survey, one indicated that it was not regulated by RSPA/OPS, one indicated that it no longer had a pipeline, and three indicated that their operations were handled by another control center on the mailing list. Of the remaining 91 companies, 79 returned the survey

[48] See appendix D for a copy of the survey.

[49] Some control centers managed multiple pipelines.

[50] Appendix E contains tabulations for each of the 67 questionnaire items.

and 12 chose not to participate. In total, 87 percent of the control centers targeted by the survey responded. In addition, several companies returned multiple surveys to reflect the use of multiple SCADA systems at their sites.[51]

The vast majority of companies controlled their pipelines with SCADA systems or the equivalent (such as distributed control systems). Of the 91 responding control centers, only 7 reported no use of SCADA. Of the companies not using SCADA, 2 operated pipelines under 500 miles in length and 5 operated pipelines under 100 miles. The size of all companies that responded to the survey is shown in figure 3.1. The median size was 500-999 miles; 11 survey responses did not record a size.[52]

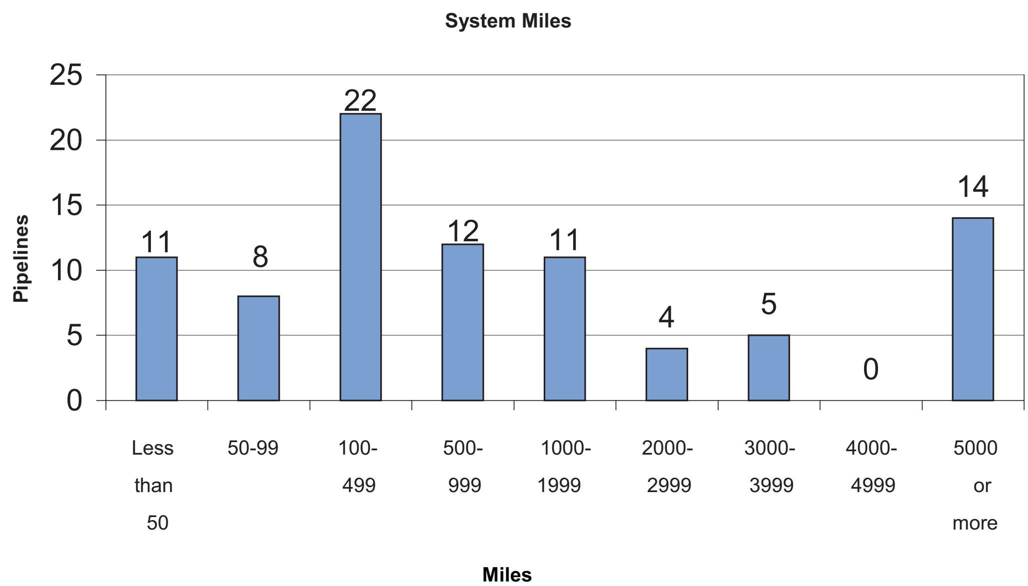


**Figure 3.1.** Number of miles reported for each control center.

The date of a company's first use of a SCADA system is shown in figure 3.2. Six of the nine companies that had SCADA in the 1960s operated pipelines more than 1,000 miles in length. Of all the companies reporting a SCADA system, 28 percent reported having a SCADA simulator.

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[51] In total, the Board received 98 responses.

[52] The missing category represents surveys in which no data were entered for the question. In many cases, the missing data are from a survey that reported on a second or third SCADA system at a control center.

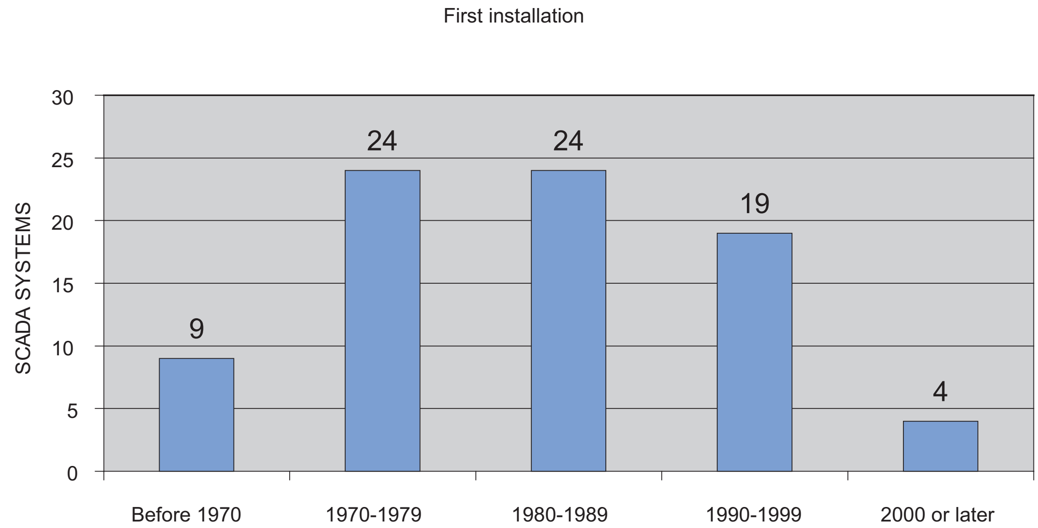


**Figure 3.2.** Date of first installation of SCADA systems.

The most prominent commodities carried by the pipeline companies surveyed were crude oil, gasoline, and diesel fuel. The "other" category of liquids (consisting of carbon dioxide and anhydrous ammonia) carried the least; these companies tended to be smaller, with pipelines of less than 1,000 miles. The distribution of pipeline commodities is shown in figure 3.3.[53] The 7 companies not using SCADA systems transported a variety of commodities: crude oil (3), gasoline (2), diesel (2), highly volatile liquids (3), natural gas liquids (3), chemicals (1), and jet fuel (1).[54]

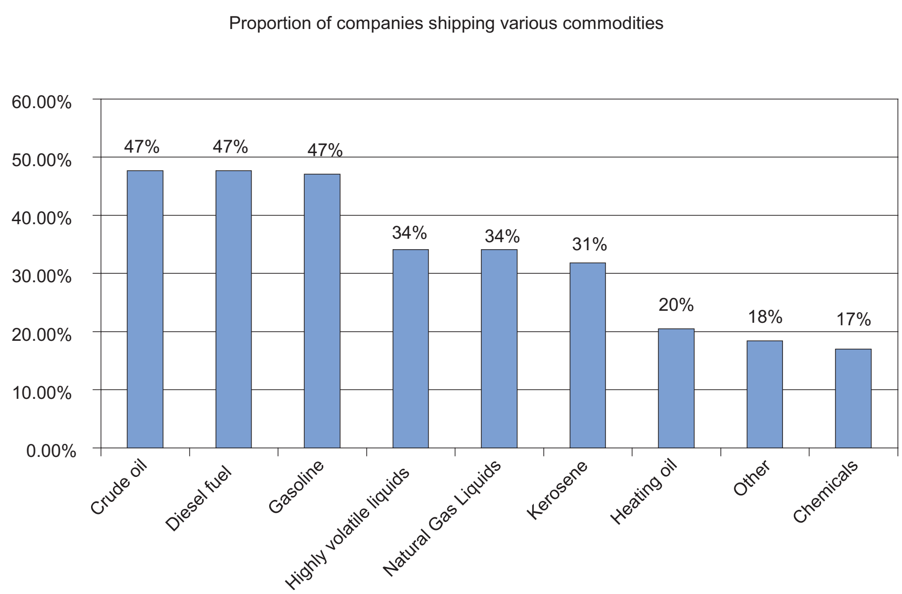


**Figure 3.3.** Commodities carried by surveyed pipeline companies.

[53] More than one commodity was carried by several pipelines.

[54] Four companies not using SCADA systems reported transporting multiple products.

### *Leak Detection*

Slightly more than 58 percent of the companies reported using CPM with their SCADA systems to assess the product flow. The most common CPM method was based upon pressure and flow monitoring (63 percent). About 45 percent of the companies used systems based either on line or volume balance, and about 53 percent of the pipeline companies with CPM systems reported detecting a leak first with the CPM on the SCADA system.

### *Alarms*

Most companies (74 percent) reported prioritizing alarms in some fashion. The most common number of alarm levels was 3, reported by 40 percent of the companies. The number of alarm levels reported is shown in figure 3.4. Although most companies reported reviewing these alarms periodically, 33 percent reported that they did not audit alarms periodically.

The Safety Board survey of pipeline operators also asked control centers if the OPS had reviewed their current SCADA systems. One-third of the companies responded that OPS had never examined their SCADA systems. OPS inspected the SCADA system for 53.7 percent of the companies as part of its standard inspection. For another 12.2 percent, OPS inspected SCADA during a record review and for 11 percent, during an accident investigation.[55]

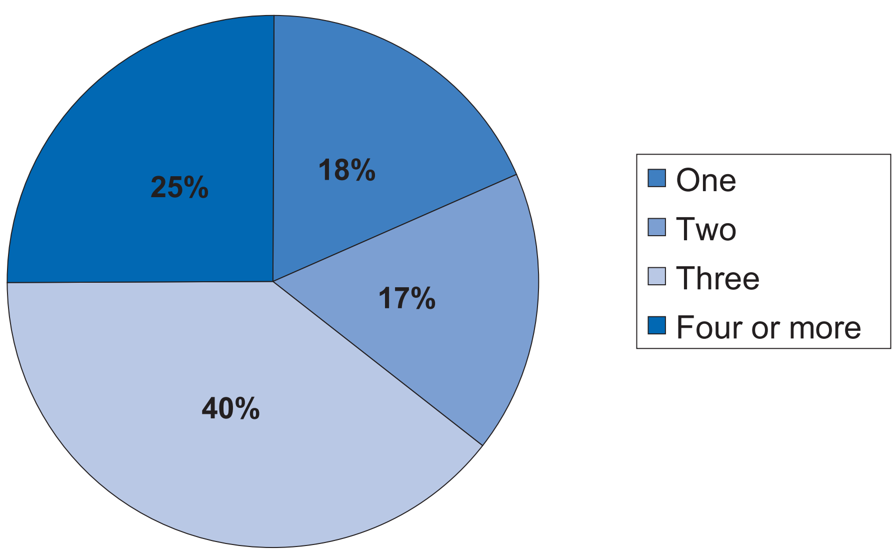


**Figure 3.4.** How many priorities of alarms does your company have?

[55] Some companies listed more than one reason for an OPS inspection.

Most companies surveyed indicated that SCADA systems have made pipeline operations safer (figure 3.5), and none of the companies surveyed disagreed or strongly disagreed with the statement that SCADA systems have allowed safer operations. Further, the companies indicated a belief that SCADA systems also allow for more efficient operations (figure 3.6).

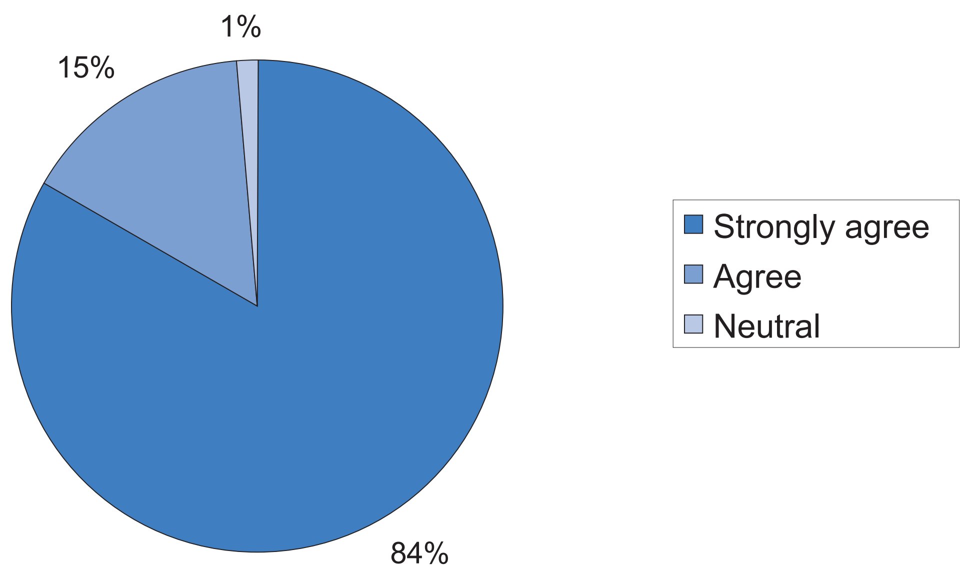


**Figure 3.5.** SCADA systems allow for safer operations.

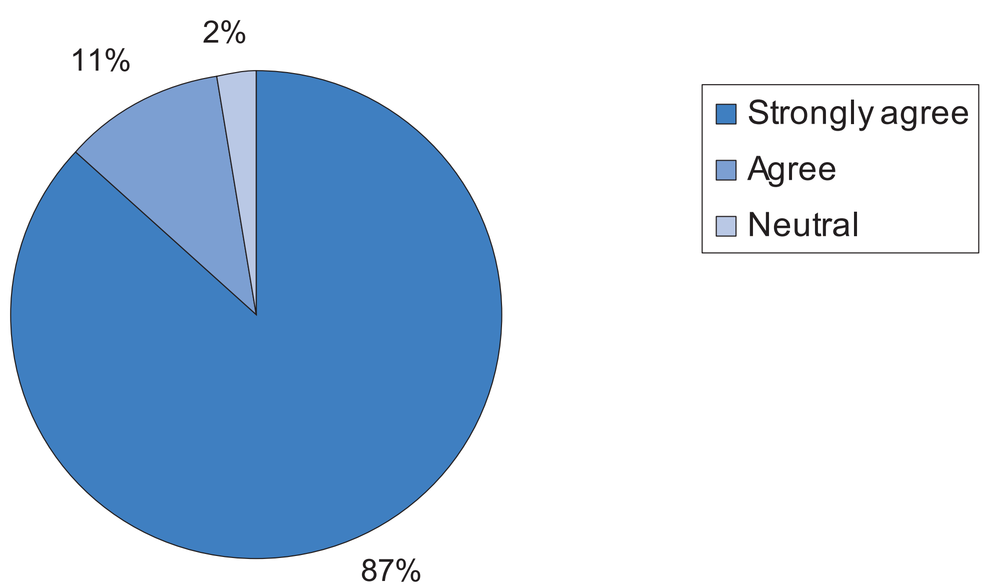


**Figure 3.6.** SCADA systems allow for more efficient operations.

# Chapter 4

# Site Visits

In addition to obtaining survey data, the Safety Board visited 12 pipeline companies that had operating SCADA systems.[56] These companies were selected on the basis of information from the general survey. The Board selected companies to include a balance of both small and large operations, as well as a variety of SCADA systems and commodities transported.

The Safety Board interviewed personnel who developed and used SCADA systems for the pipeline company. A total of 69 persons were interviewed. Each interview covered a standard set of topics to ensure consistency of information among the pipeline companies visited. Interviewed personnel included controllers, supervisors, and SCADA systems managers. In addition, the Board examined the SCADA system and reviewed its design and development with a company representative who was responsible for the system's operation and maintenance. The Board also reviewed SCADA-related job aids that controllers used during the course of their work. Job experience for the persons interviewed varied, as shown in table 4.1. Controllers tended to have the longest tenure, with an average of 7 years on the job.

**Table 4.1. Job experience of individuals interviewed for the SCADA Study.**

| Position | Minimum Experience | Maximum Experience | Average | Personnel Interviewed |
|---|---|---|---|---|
| Controller | 0.5 | 23.5 | 7 | 18 |
| SCADA Manager/Analyst | 0.5 | 13.0 | 4 | 16 |
| Supervisor | 0.13 | 7 | 3 | 12 |
| Training Manager | 0.5 | 9 | 3.5 | 12 |
| Safety Officer | 1.0 | 10 | 5.0 | 11 |

The Safety Board visited the 12 companies from November 2003 through September 2004 for 1 or 2 days. All site visits were voluntary for the companies. Three companies[57] that were initially contacted decided not to participate in the site visit phase of this study and substitutes were identified. Of the sites visited, two companies controlled pipelines under 100 miles in length, three controlled 100-499 miles of pipelines, two controlled 500-999 miles, one had 1,000-2,999 miles, and four had over 3,000 miles. Commodities carried included chemicals, carbon dioxide, refined products, crude oil, natural gas liquids, and anhydrous ammonia. Two of the companies had a primary responsibility involving process control while the other 10 were primarily responsible for pipeline control. Table 4.2 summarizes the 12 site visits.

[56] These 12 companies represent 13 percent of the 91 liquid pipeline operators identified for the study.

[57] All of the companies who declined to participate reported not using SCADA systems for their pipelines.

| Table 4.2 Site visit company characteristics. | | | | |
|---|---|---|---|---|
| Site | Line Miles | Controllers per shift | Shift length | System |
| 1 | 5,000+ | 8 | 12 Hr | Oasys |
| 2 | 3,000-3999 | 5 | 12 Hr | UCOS |
| 3 | 500-999 | 3 | 12 Hr | Oasys |
| 4 | 50-99 | 1 | 12 Hr | Intellutions |
| 5 | 3000-3999 | 2 | 12 Hr | FactorySuite 2000 |
| 6 | 500-999 | 2 | 12 Hr | Fisher Roc Intellutions |
| 7 | 100-499 | 1 | 8 Hr[a] | Plantscape |
| 8 | 50-99 | 1 | 12 Hr | Oasys |
| 9 | 1000-1999 | 2 | 12 Hr | Cimplicity Plant Edition |
| 10 | 100-499 | 1 | 12 Hr | Realflex |
| 11 | 3000-3999 | 4 | 12 Hr | S/3 SCADA |
| 12 | 100-499 | 1 | 12 Hr | FoxSCADA |

a. The SCADA system was monitored on site only during business hours. During non-business hours, when an alarm occurred, the system called the receptionist or an answering service to report the alarm to the on-call controller.

The 12 companies visited used a variety of SCADA systems, as shown in table 4.2. One company did not use a system to control its pipeline; only the output of the plant and the pipeline near the plant were controlled and monitored by SCADA computer systems.

**Figure 4.1.** Control console example for small operations.

Five sites were operated by a single controller. At these small centers, like the one pictured in figure 4.1, the console consisted of one to two monitors placed together. The monitors in this case backed up to a window that allowed the controller to view pipeline equipment outside. Two control centers performed process control tasks and had control consoles that were similar to the smallest centers in that they had only one workstation. However, these workstations could contain more than one monitor for the controller to use. For example, one center was configured with one monitor related to pipeline operations and six related to process control tasks. These monitors were laid horizontally on tables set in a "U" shape. An additional seven screens were associated with a new system coming online. The controller at this site noted that fewer monitors would be "nice." Another single-controller operation had three screens set horizontally for monitoring process control.

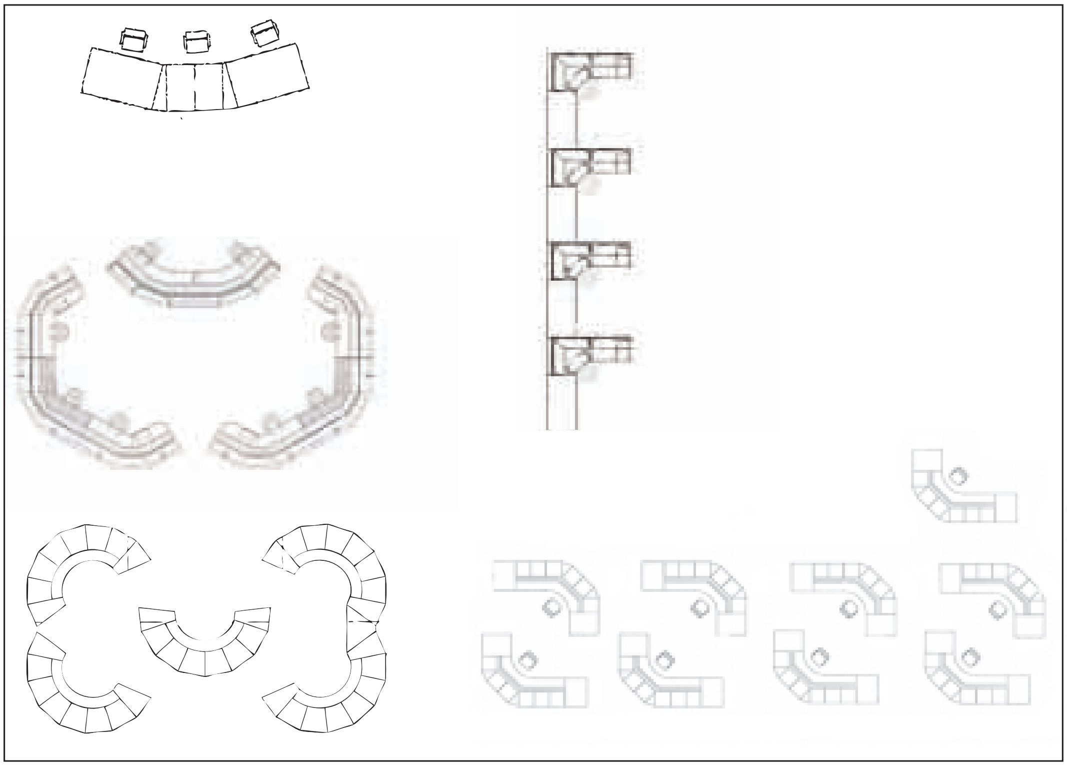

**Figure 4.2.** Console arrangements at larger operations.

The seven systems with more than one controller operating at a time had organized their controllers in a variety of layouts, as shown in figure 4.2. In all centers with multiple controllers operating simultaneously, all consoles were located in the same room, showing the value those companies placed on having all control personnel close together. At one site, supervisors sat at consoles near the controllers so that they could interact with the controllers regularly. Supervisors indicated the importance of being aware of what was happening on the pipelines quickly should a problem occur. However, in some centers, supervisors were located in offices adjacent to the control center but were not in the same room.

Supervisors indicated the following desirable characteristics of control center layouts: providing everything close to the controllers, allowing for room to expand, allowing controllers to interact easily, having an open layout to facilitate communication, and having layouts that limited non-controllers from walking through the room. Areas for improvement in the layout included moving controllers so that they could work more closely together and finding a bigger room.

Most controllers liked their workstation layouts. They indicated that they could reach everything and had a centered view of their screens, that screens were at eye level, and that noise was limited. The controllers identified no problems with the room temperature, lighting, or screen glare, but some complained that their workstations had stacked monitors like those in figure 4.3 that were difficult to monitor or caused neck strain.[58]

**Figure 4.3.** Centers with stacked monitors due to space constraints.

## SCADA Screens and Graphics

During the site visits, the Safety Board was provided with exemplar screens of the company's SCADA system in order to obtain information about the displays and their use of graphics. A wide variety of screen displays were submitted. Controllers indicated that the screens they used most often were the system/overview screen, station/location screens, alarms screens, and CPM or leak detection screens.

The system/overview screen provided information to controllers about data across the line. Most of these displays were schematic representations like the one in figure 4.4, but some companies represented the system in a tabular format (figure 4.5). The schematic format reportedly helped controllers see information by mapping the physical characteristics of the pipeline to the display, allowing controllers to rapidly detect where problems occurred along the physical pipeline. The tabular format was reported to assist controllers by grouping specific information according to operational characteristics, allowing controllers to quickly see certain parameters (for example, pipeline pressure) across the whole pipeline and easily compare the values of that parameter with the parameter at another location on the pipeline.

[58] Three of the five persons interviewed at centers with stacked monitors noted this concern.

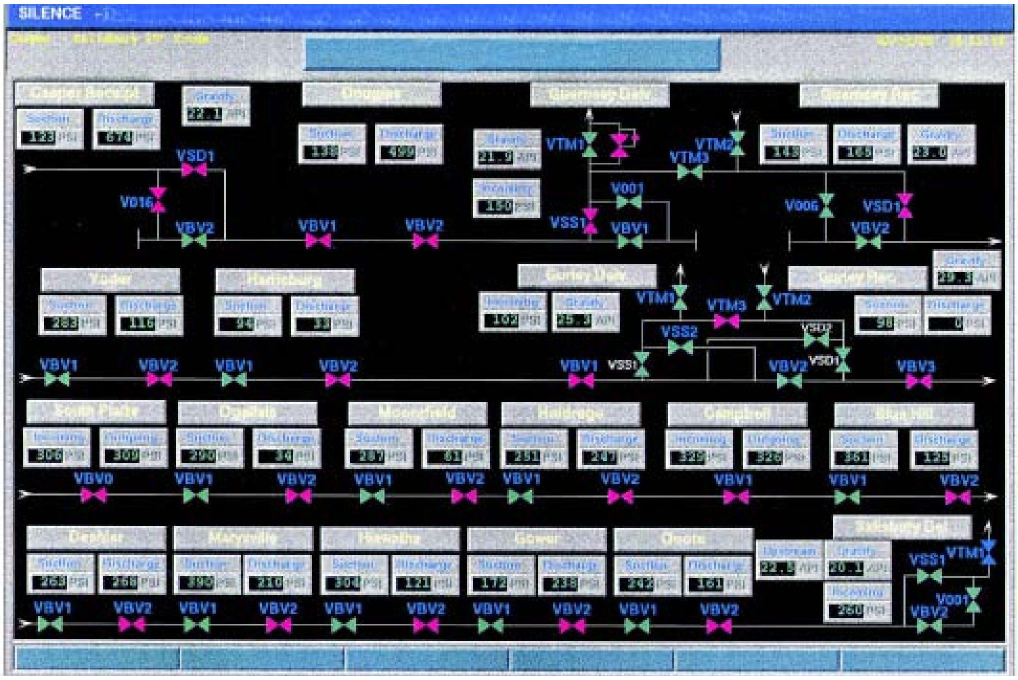


**Figure 4.4.** Schematic representation of pipeline system organizes information in a manner consistent with the physical layout of the pipeline.

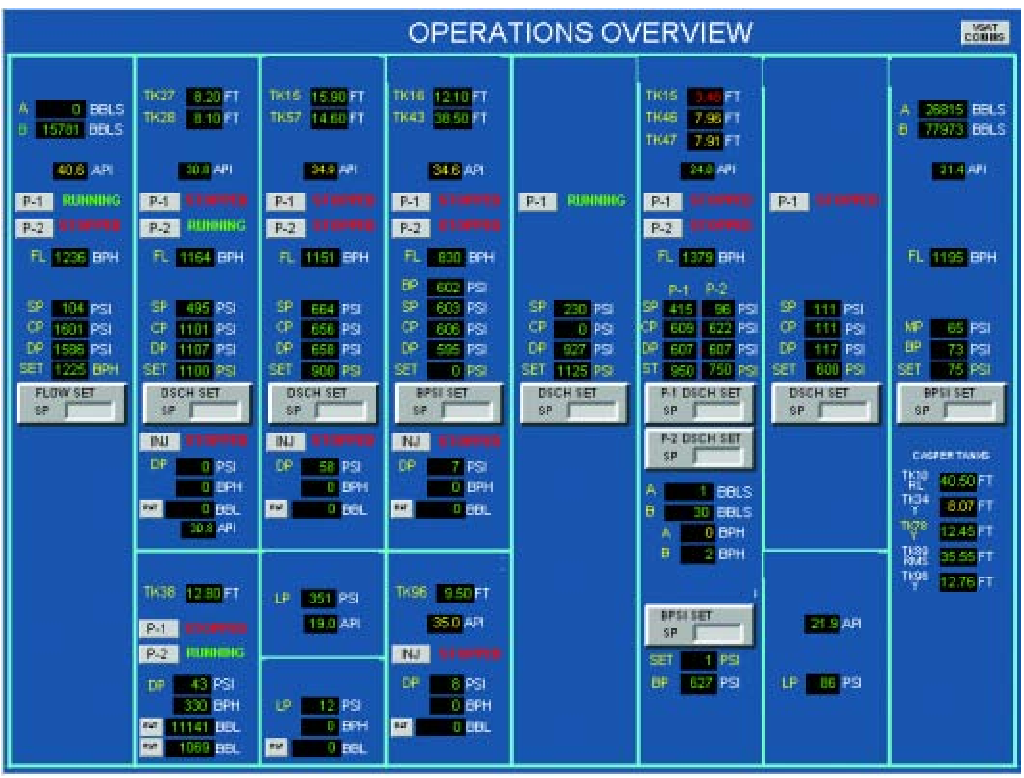


**Figure 4.5.** A tabular representation of a pipeline system organizes information in columns based upon the information content.

The station/location screen allowed controllers to see equipment at different stations along the pipeline. From this screen, controllers could activate/deactivate pumps and open/close valves. Controllers also used this screen to set the parameters for the SCADA system to monitor for values outside the set points. An example of a station screen is shown in figure 4.6. The controller may also be able to initiate emergency shutdown (ESD) routines from the station screen as indicated by the ESD button in the upper right corner of the figure.

At one company, the station/location screen had to be displayed at all times. The alarm screen was mandatory at another company and the CPM screen was mandatory at a third. Otherwise, controllers were free to arrange their SCADA screens to fit their preferences. Alarm and CPM screens are discussed in detail later in this chapter.

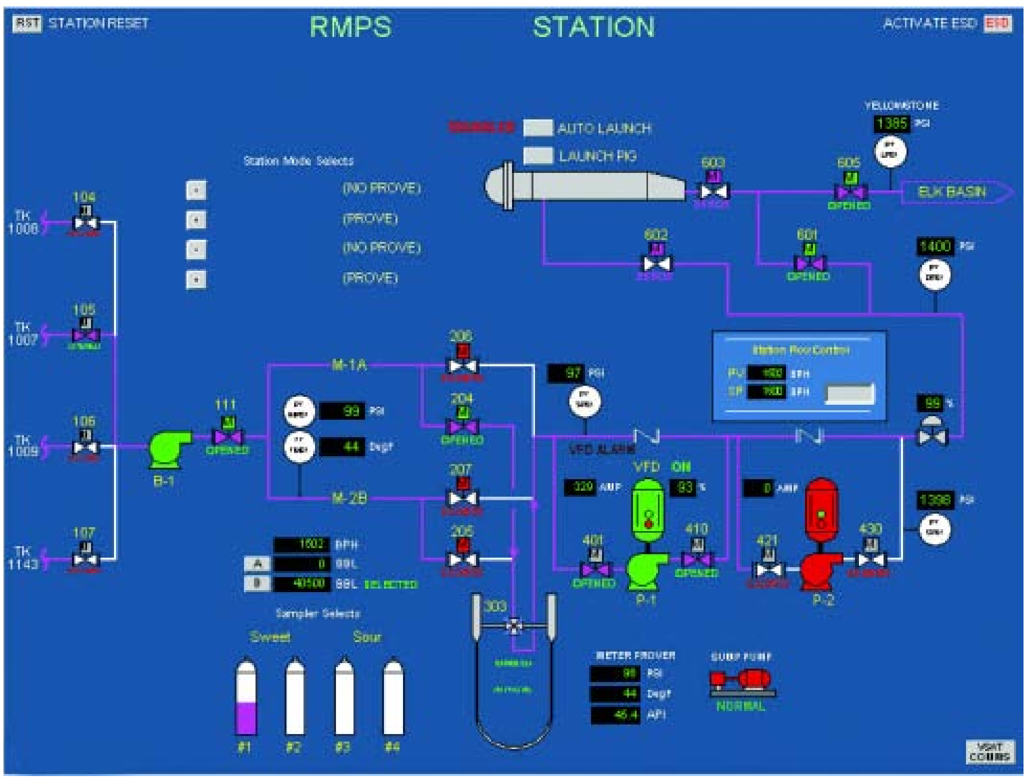


**Figure 4.6.** The figure shows a typical station screen.

In addition to studying what the SCADA screens displayed, the Safety Board considered how that information was displayed, including the choice of colors, the use of graphics and symbols, and the arrangement and amount of information on the screen.

Background colors for the screens ranged from a light gray or light blue to black. In four SCADA display screens, the contrast between the light background and the colors used in the display was too slight to display some of the foreground elements clearly. However, most displays provided good contrast, using dark backgrounds—black, blue, or gray—with color foregrounds that were clearly visible. Figure 4.7 shows how a light background combined with light foreground colors creates obscurity, and figure 4.8 shows an example of foreground colors on backgrounds being easy to read. The FAA Human Factors Design Standard indicates, "foreground colors [text] should be readily distinguishable from background colors".[59]


**Figure 4.7.** Light background with light colored foreground makes reading yellow text in center of display difficult. The yellow text shows alarms such as a battery alarm in the black rectangle above.

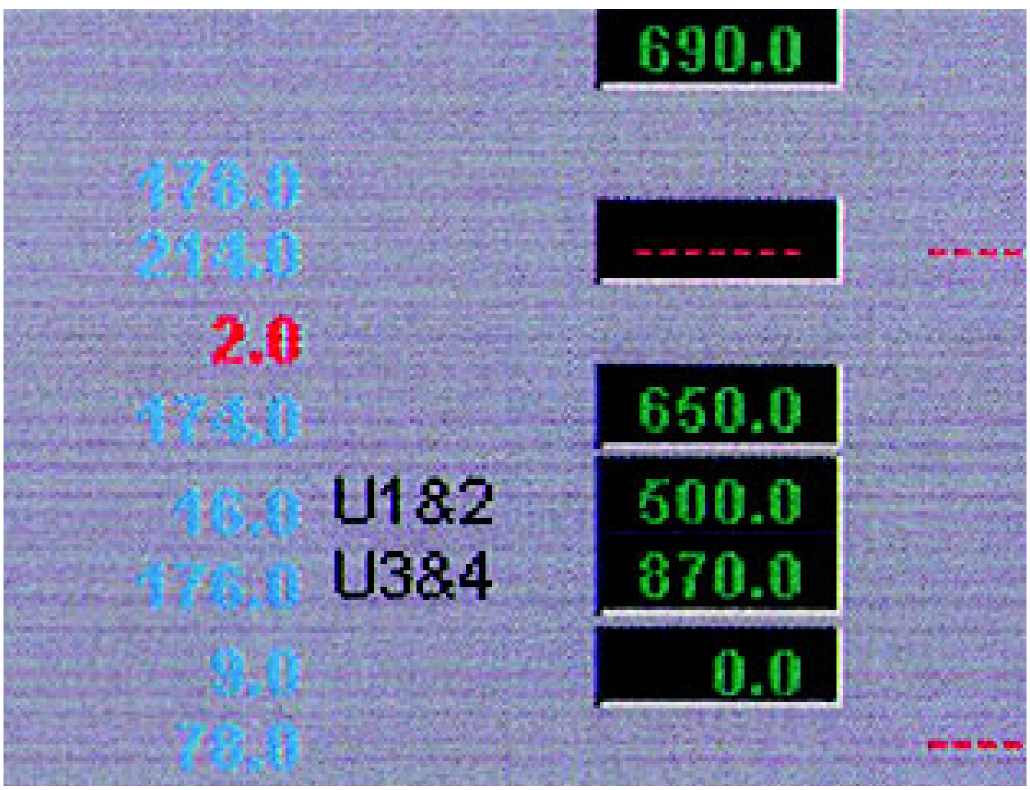


**Figure 4.8.** An example of foreground colors distinguishable from background colors.

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[59] Department of Transportation, Federal Aviation Administration, *Human Factors Design Standard*, DOT/FAA/HF-STD-001 (Atlantic City International Airport, NJ: William J. Hughes Technical Center, 2003).

None of the companies used monochromatic displays. The summary/station screens displayed from 5 to 15 colors, and most colors were assigned a specific meaning. According to the Instrumentation, Systems, and Automation Society (ISA), the optimal number of colors to display is from 5 to 7.[60] Four companies used 8 or more different colors.

The complexity of the system displays also varied from company to company. However, in some cases, both large and small systems were displayed using a cluttered format. According to ISA, the goal for display design is to allow 25 to 40 percent blank space.[61] The FAA uses the goal of 40 percent of blank space on a screen to avoid clutter.[62] However, four display examples collected by the Safety Board had very little blank space. Figure 4.9 gives an example of a cluttered and uncluttered pipeline SCADA screen.

**Figure 4.9.** The screen on the right is cluttered while the screen on the left is uncluttered.

The Safety Board also examined the color-vision implications of the displays and found that five companies used colors without redundant coding that would be difficult for colorblind persons to detect.[63] In the example in figure 4.10, a colorblind operator could not detect the difference between a running pump (green) and a stopped pump (red). Several of the companies visited did not test for colorblindness when selecting controllers, including the company that used the exemplar screen. Also, one company used the color red as both a label and a warning indicator, resulting in an inconsistent message. The dual use of color under emergency settings can be problematic.[64]

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[60] *Fossil Fuel Power Plant-Human Machine Interface-CRT Displays*, 1996, ISA-TR77.60.04-1996.

[61] ISA-TR77.60.04.

[62] DOT/FAA/HF-STD-001.

[63] About 8 percent of males and 1 percent of females in the population are red-green colorblind.

[64] J. Gluckman, *Human System Integration in Pipeline Control*, Integrated Dynamics, Inc. (1996).

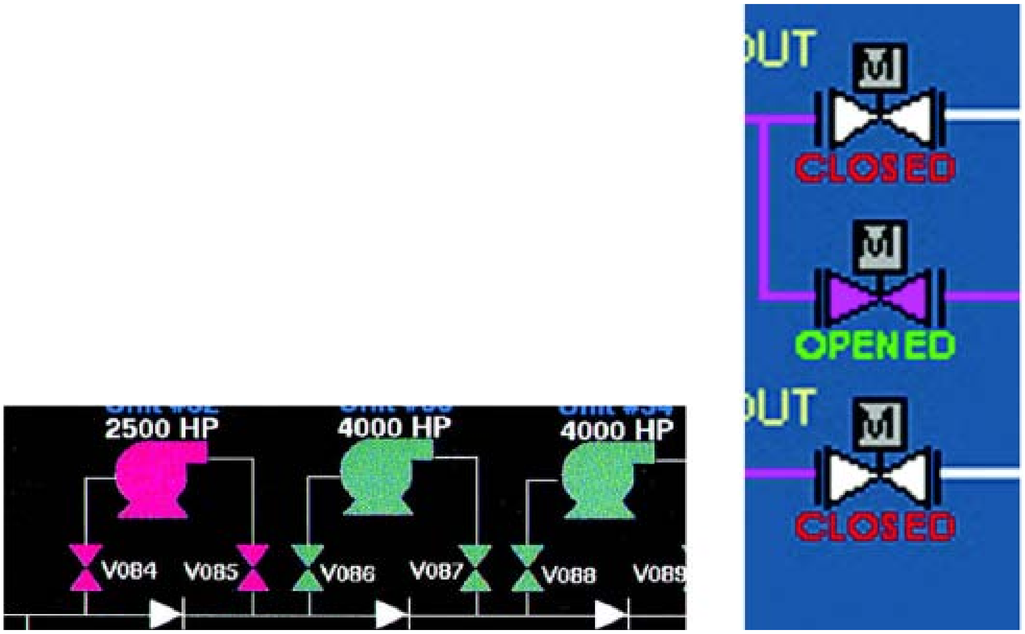


**Figure 4.10.** The display on the right uses only one attribute to show the status of a pump (color) while the screen on the left uses two attributes: color and text.

Controllers described several other issues meriting mention. On one system, the mouse cursor was difficult to see due to the low contrast of the pointer with the background. Both the SCADA manager and the controller at this site commented on this as an area that needed improvement. The Nuclear Regulatory Commission's interface design guidelines[65] indicate that "cursors should have distinctive visual features" that allow a controller to readily detect the cursor position. On another system, the lines used to show the flow path were too narrow to follow the product path easily.

Each graphics system that the Safety Board examined was developed by individual pipeline companies, often in conjunction with the SCADA systems developer. As such, no two system designs were exactly alike. One thing that was observed among all the systems visited was a limited use of standards in designing the system screens. When asked what standards were used in the design of the screens, no SCADA manager reported using standards for screen design; at most, SCADA managers used internal guidelines to ensure that one system at a company was consistent with another.

### *Alarm Philosophy*

Controllers were asked how SCADA systems had helped prevent incidents from occurring. Eleven of the eighteen controllers indicated that alarms were the most important safety feature of the SCADA system. All supervisors saw SCADA as an asset during abnormal operations and three supervisors specifically cited alarms as the feature that most benefits safety.

[65] Nuclear Regulatory Commission, *Human-System Interface Design Review Guideline,* NUREG-0700, Rev. 1, Vol. 1 (Washington, DC, 1981).

Although a SCADA system can produce many types of alarms, the Safety Board focused on the alarms that are most likely to indicate a leak on a pipeline. Based on the review of Safety Board investigated accidents, controllers can receive an alarm indicating a leak has occurred and fail to take the appropriate response to the alarm. The alarms from these accidents that indicated leaks include leak alarms from a CPM algorithm, unexplained pump shutdowns, and sudden changes in flow rate or pressure on the line. The types of alarms that can indicate a leak need to be easy to identify and interpret. The Safety Board, therefore, discussed with pipeline companies their procedures to ensure clear indication of alarms that could indicate leaks.

Controllers can receive up to 100 alarms an hour as two pipeline controllers reported. These alarms are presented on an alarm page. An example of an alarm page can be seen in figure 4.11. The upper half displays alarms that the controller has not yet acknowledged, and the lower half displays the alarms that the controller has acknowledged previously. Controllers who need to review the alarm history can scroll through the alarms at the bottom of the page. The first column names the alarm, the second indicates an alarm's priority, the third describes the alarms, and the last gives the time the alarm occurred.

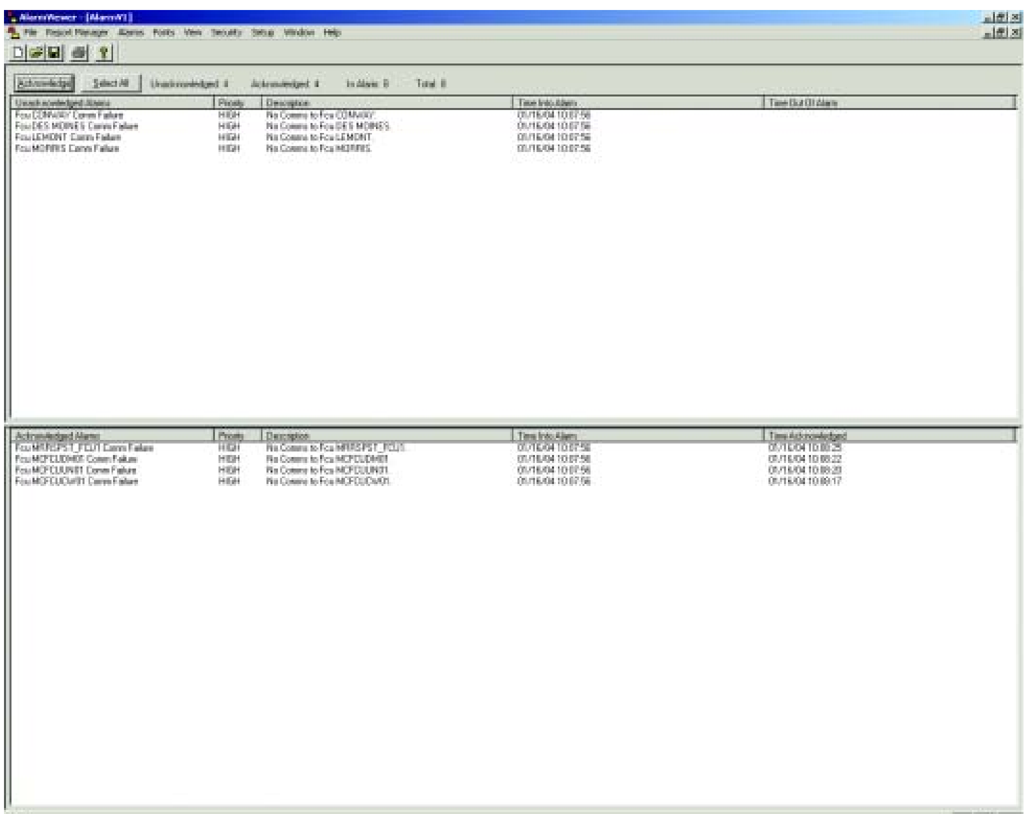

**Figure 4.11.** Alarm summary page.

Alarm information is often color-coded to show a level of priority and may also be displayed with an auditory code. In figure 4.12, the text in red indicates critical alarms, and the text in yellow indicates warnings. Green alarms, not shown on the screen, provide general information. In this example, the alarms are arranged by priority and then by time so that the most important alarms are on top. To acknowledge the alarm, a controller can either click on the alarm text or press the “page acknowledge” button to acknowledge all visible alarms.

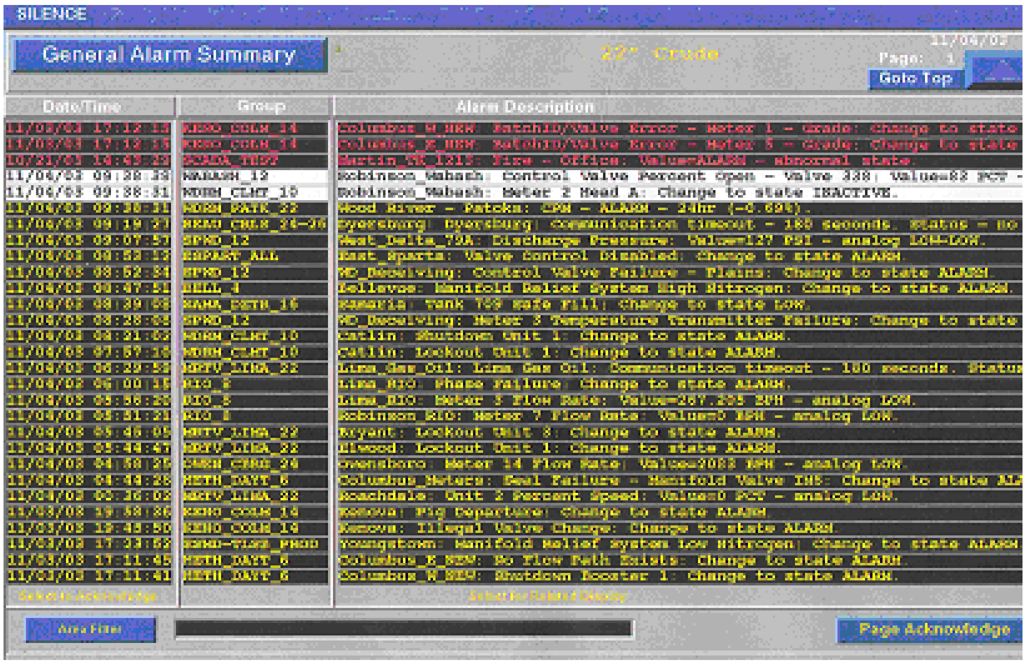


**Figure 4.12.** Alarm summary page with color-coded priority.

SCADA managers reported that their alarms were both visual and auditory. Eight SCADA managers indicated that their companies had a policy of prioritizing alarms. One of these companies reported that priorities were added because “alarms were slipping through the cracks.” A ninth company did not prioritize alarms but had begun planning for prioritized alarms. In most systems, alarms were presented both on an alarm page and the station page. Alarms appearing on the station page are illustrated in figure 4.13. The alarms in this figure appear in red and yellow. By selecting the alarm text displayed on the system page, controllers would be taken to the alarm page.

Seven companies reported that they reviewed alarms regularly: either the SCADA manager examined alarm logs periodically (daily or monthly), or the controllers conducted alarm reviews (monthly). One company was conducting a study on alarms. Three other companies provided little detail on the review process other than that it involved working with the controllers and that there was no formal process. One manager noted a reduction of 5,000 alarms a day in the control center to 1,000 by working with controllers to develop guidelines for more realistic alarm set points.

Controllers reported getting from 5 to about 20 alarms an hour. However, as stated before, two controllers reported at times receiving more than 100 per hour. Although most controllers indicated that they received the right number of alarms, four indicated that they received too many. Three of these controllers worked at sites with no alarm review policy and the fourth worked at the site that was conducting the alarm study.

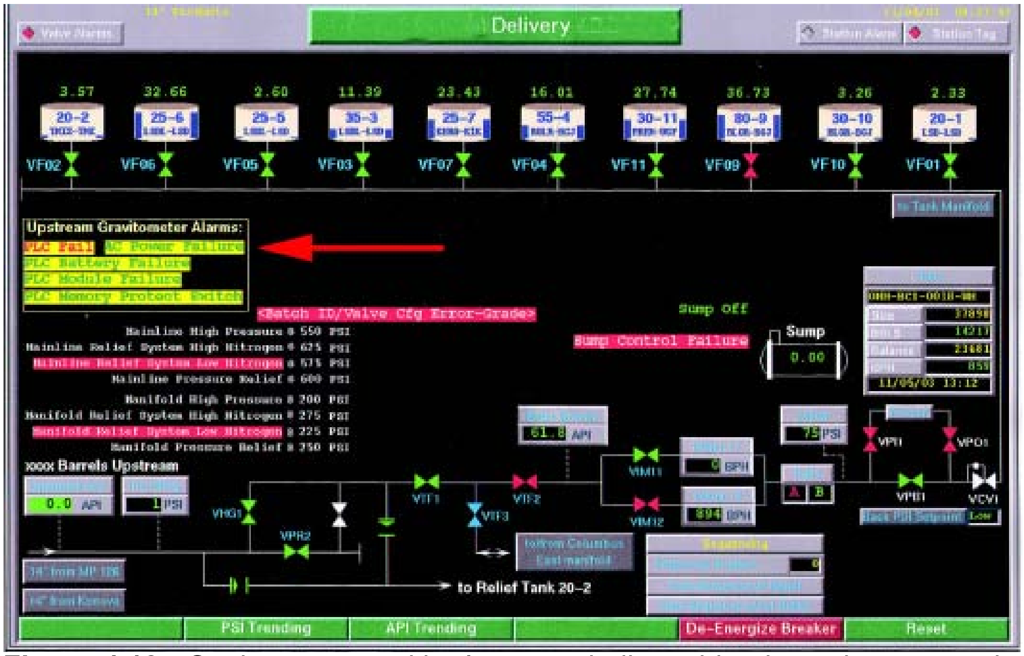


**Figure 4.13.** Station screen with alarms as indicated by the red arrow on the screen. Indicating alarms on screens that controllers use regularly increases the likelihood of detection of the alarms by controllers.

## Training and Selection

Site visits showed that almost every controller who began a training course finished it. Only one company reported that people had dropped out of the training (2 out of 20 did not complete training). Most trainees had previous pipeline experience, although half the companies reported hiring from outside the industry on occasion. The length of training averaged about 6 months and ranged from 3 months to several years.

The primary method of evaluating potential controllers during the selection process was through interviews. Three companies supplemented the interview process with testing, personality inventories, or company-developed selection tools. Supplemental tools included psychological stress testing, a targeted selection process based on 13 dimensions, testing for motivational fit, stress tolerance testing, and math-based pattern recognition (that is, testing the ability to recognize patterns quickly). The companies were not asked about visual acuity or color perception tests, but three companies volunteered that no color vision testing was conducted.

The training at each site consisted primarily of on-the-job training and a review of company operating manuals. Most companies (10 of 12) reported using some form of computer-based training (CBT), seven companies reported using classroom training, and six reported using a simulator. The proportion of time spent in various training situations is shown in table 4.3. On-the-job training and review of manuals accounted for over 70 percent of controller training.

| Table 4.3. Percent of initial training using different methods.[a] | | | | | | |
|---|---|---|---|---|---|---|
| Site | OJT | Classroom | CBT | Simulator | Manuals | Other[b] |
| 1 | 27 | 23 | 1 | 11 | 4 | 24 |
| 2 | 50 | 5 | 15 | 5 | 20 | 5 |
| 4 | 100 | 0 | 0 | 0 | 0 | 0 |
| 5 | 50 | 0 | 10 | 0 | 30 | 10 |
| 6 | 60 | 16 | 8 | 12 | 2 | 1 |
| 7 | 90 | 5 | 5 | 0 | 0 | 0 |
| 8 | 50 | 5 | 20 | 25 | 0 | 0 |
| 9 | 80 | 0 | 0 | 0 | 20 | 0 |
| 11 | 60 | 0 | 10 | 5 | 10 | 15 |

a. Three companies did not indicate a breakdown of their training methods.

b. This category includes bulletins, handbooks, workbooks, and other materials.

Although 10 companies reported using CBT, CBT accounted for only about 5 percent of controller training. At some sites, CBT focused on company policies, but several training coordinators reported using CBT for teaching hydraulics and pump operation. Two training coordinators planned to increase the use of CBT for training.

Six companies used simulators and reported them as useful for training, although at three of the sites, the simulator was not yet a formal part of training. Each company reported being able to simulate abnormal conditions like leaks and equipment failure. Most emphasized the simulator's usefulness in simulating leaks—that is, "breaking the pipeline without actually breaking the pipeline." Four of the six companies had simulators that reflected their operational configuration of screens and hydraulics. The simulator itself did not have to reflect the consoles that the employees typically used. For example, figure 4.14 represents a console at one site and the simulator used at that company.

**Figure 4.14.** A SCADA console is shown on the left with a simulator on the right indicating that simulators need not be exactly the same as the SCADA console.

In general, all sites with simulators were still developing simulator training. One company did report using the simulator to train new controllers using previous accident data. A second company reported using the simulator to test controllers to determine if they could perform required operation qualification tasks, such as leak detection. Another tested its controllers using actual line data. The scenarios that were tested included start-up, start-up with communication failure, running with a leak, running with a power failure, running with a small leak, and running with a blocked valve. Only 6 of the 18 controllers had ever trained on a simulator, but all 6 of the training managers interviewed planned to increase the use of simulator training at their sites.

One company reported developing a chart as a decision aid to help controllers when operations were not normal. The chart helped controllers to establish the facts about any deviation from normal and to identify appropriate actions to take in response to those facts. Three companies reported developing or beginning to develop tools to help controllers when certain alarms appear. These aids included flowcharts or, in one case, a decision matrix.

## Fatigue Management

All but one control center worked 12-hour shifts, but the cycle of shifts differed. One center scheduled its controllers on a month of days followed by a month of nights. One center manned the control center only during business hours. The remaining centers alternated days and nights on a variety of 4-day, 3-day, or 2-day work shifts. Schedules for sites with 12-hour shifts are shown in table 4.4.[66]

**Table 4.4. Controller schedule rotations. D indicates a day shift for a controller while N indicates a night shift. Blank spaces indicate days off for the controller.**

| | Day of the Week | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Site** | **M** | **T** | **W** | **T** | **F** | **S** | **S** | **M** | **T** | **W** | **T** | **F** | **S** | **S** |
| **10 (2 weeks)** | | D | D | D | D | | | | | N | N | N | N | |
| **(2 weeks)** | | | | N | N | N | N | | | | | N | N | N |
| **6** | | N | N | | | N | N | N | | | N | N | | |
| | D | D | | | D | D | D | | | D | D | | | |
| **2** | | | N | N | N | N | | | | D | D | D | | |
| | N | N | N | | | D | D | D | D | | | | | |
| **8** | D | D | | N | N | N | | | | D | D | | | |
| | N | N | | | D | D | D | | N | N | | | | |
| **11** | N | N | | | | D | D | D | | N | N | | | |
| | | D | D | | N | N | N | | | | D | D | | |
| **1** | N | N | | | N | N | | | | N | N | | | N |
| | N | N | | | N | N | N | | | D | D | | | D |
| **9** | D | D | D | D | | | N | N | N | | | D | D | D |
| | | | N | N | | | | | | | | | D | D |
| **5** | N | N | N | N | | | | D | D | D | | N | N | N |
| | | | D | D | D | D | | | | | | | | N |
| **3** | D | D | | | N | N | N | | | D | D | | | |
| | N | N | | | D | D | D | | | N | N | | | |
| **4** | D | D | | | D | D | D | | | D | D | | | |
| | D | D | | | D | D | D | | | D | D | | | |

[66] One center with 12-hour shifts did not report the rotation shifts while the other center did not work a rotating 12-hour shift.

The aspect of the job least liked by the 18 controllers interviewed was the 12-hour shift (8 of 18 respondents).[67] Controllers reported problems with working nights (2 responses), not getting enough sleep (3 responses), "swings" to dayshift (4 responses), and covering for someone else (2 responses). One controller commented that when another controller called in sick, the outgoing controller would work an extra 6 hours and the next controller would arrive 6 hours early, resulting in 18-hour shifts. Conversely, most controllers enjoyed the extra time off afforded by the 12-hour shift. Three controllers commended their companies for providing informational handouts about how to manage a 12-hour shift.

Controllers at all companies noted that break time was very limited. Most companies allowed for very short breaks. During breaks, controllers usually coordinated with a co-controller to monitor the pipeline. In smaller operations, controllers asked supervisors to monitor that station. In one case, SCADA system alarms were linked to a telephone system that called the reception desk or an answering service to report the alarm to the controller.

Shift change requirements can add up to a half an hour to the length of a controller's day. At the end of a shift, controllers reported that they met with the next controller coming on duty to discuss the current pipeline situation. The information exchange ranged from a standardized discussion with a developed list of topics to a general discussion of what should transpire during the next shift. Five controllers mentioned using a relief or turnover sheet for shift changes. Controllers at two of the smaller companies had to inspect local pipeline equipment before starting their shifts.

## Computational Pipeline Monitoring

Seven SCADA managers reported using computerized leak detection systems. Line balance[68] was used in five centers, volume balance[69] in two, compensated mass balance[70] in three, and real time transient modeling[71] in three. Each of these leak detection systems was integrated with the SCADA system and used alarms standardized with the SCADA system. Less than half the managers reported that their systems were effective during transient conditions while all reported that their leak detection worked at steady state.[72] Managers reported getting false leak alarms routinely during startup. Of the seven centers that reported using leak detection, four

[67] One respondent worked a regular 8-hour day.

[68] Line balance accounts for the volume of liquid placed into a line relative to liquid leaving the line.

[69] Line balance that accounts for compression of liquid and temperature.

[70] Line balance that models for pipeline conditions between two measured points.

[71] The pipeline simulates the flow of liquid through the line and compares this simulation with the actual data to determine a leak.

[72] Transient conditions include startup or shutdown of a pipeline while steady state means the product is running through the pipeline at an unchanging rate.

controllers mentioned the leak detection system when asked how SCADA systems helped prevent incidents from occurring.

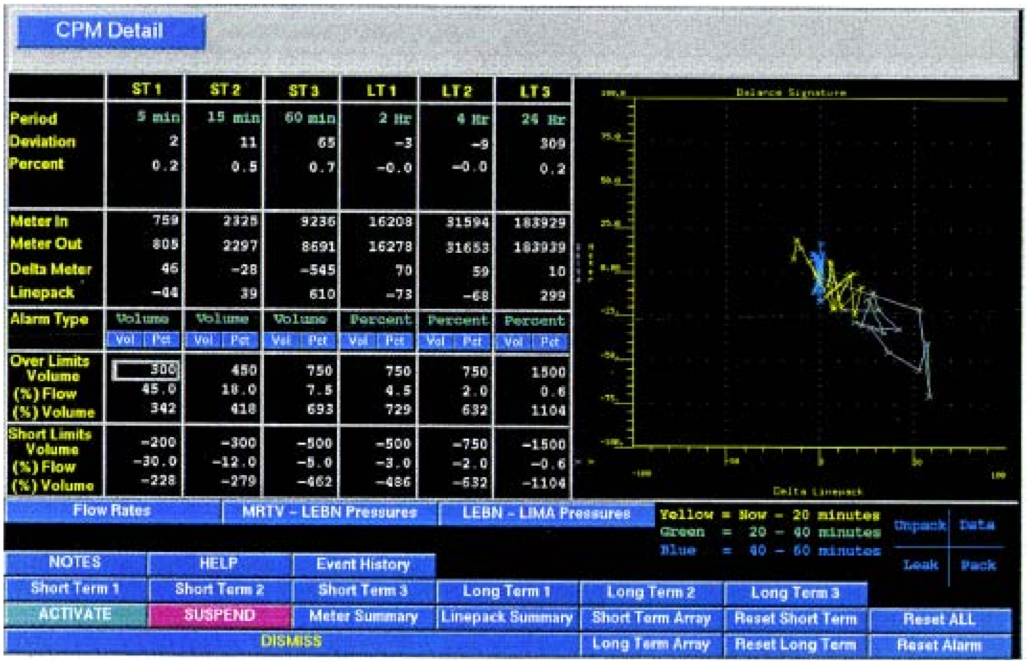


**Figure 4.15.** CPM Screen with values on the left of the screen to indicate over six time periods (three short term indicated by ST and three long term indicated by LT). On the right of the screen are three lines graphically depicting possible leaks over three time periods.

The CPM screen shown in figure 4.15 provides information about potential line imbalances over various time periods. This screen shows the time periods of 5 minutes, 15 minutes, 1 hour, 2 hours, 4 hours, and 24 hours. The graphic on the right of the screen compares the amount of line pack[73] on the x-axis with the difference between product entering the pipeline and product exiting the pipeline on the y-axis. When the line in the center of the grid tracks to the lower-right quadrant, as in the figure, the controller knows that the line is packing (the different color lines represent different time periods). Conversely, when the line tracks to the lower-left quadrant, the CPM screen indicates a potential leak in the line.

One center required controllers to use CPM screens as the primary monitoring screens for clear indications of leaks on their line (figure 4.16). On this screen, each segment of the line had a CPM graphic for controllers to monitor. At the bottom of the screen were buttons for additional screens and a list of recent alarms.

[73] "Line pack" refers to the compression of the fluid in the pipeline line fill.

SCADA managers all indicated that their CPM systems were effective at detecting leaks during both steady-state and shut-in conditions.[74] Three of the managers (50 percent) said their CPM systems were effective during transient conditions. On the other hand, four managers indicated that false alarms occurred during the startup of a line, two managers indicated false alarms during the shutdown of a line, and three managers indicated false alarms during batch changes.

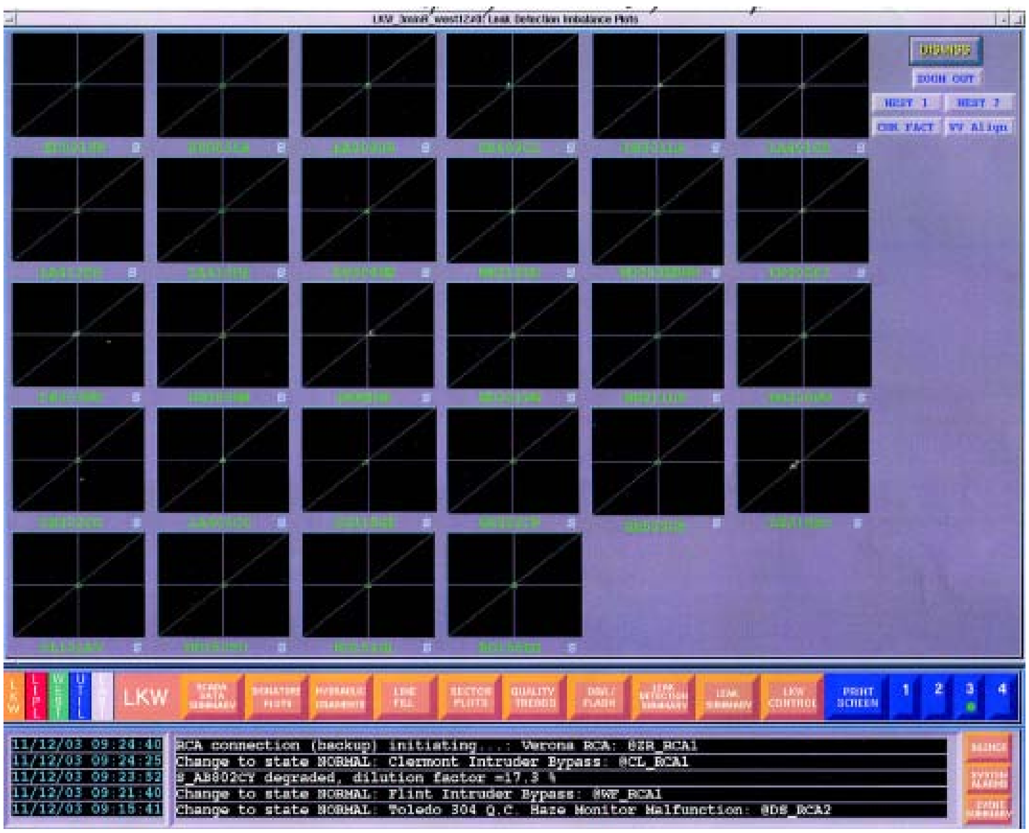


**Figure 4.16.** System screen using 28 CPM screens to allow controllers to monitor for leaks along the entire pipeline.

[74] Shut-in conditions occur when pipelines have product in the line but intake and delivery valves are closed, preventing product movement.

## Chapter 5

# Discussion

## Necessity of SCADA Systems

Most hazardous liquid pipeline operators use SCADA systems to monitor and control their pipelines. These operators reported that SCADA systems enhance both the safety and efficiency of pipeline operations. Controllers and SCADA managers from the companies the Safety Board visited agreed unanimously that their SCADA systems were helpful during potential leak events, enabling controllers to see the big picture and rapidly shut systems down following a leak. For example, the controller in the Cohasset accident[75] was able to detect a pipeline leak in approximately 3 minutes.

Although SCADA systems have been used for the last three decades, SCADA is not specifically mentioned in the pipeline regulations (Title 49 CFR Part 195). However, OPS has developed elements and criteria for inspectors to use while performing SCADA system reviews. In 2003, OPS added a SCADA-specific addendum to its inspection audit form. The addendum includes seven items that are related to the use of SCADA to comply with Part 195 requirements. In addition, pipeline inspectors began to receive special training on SCADA systems in 2001.

Since the Bellingham accident, the OPS has taken a more direct role in the oversight of SCADA systems being used by liquid pipeline companies and has developed an audit process for SCADA systems that perform functions regulated by OPS. OPS has also trained its inspectors on SCADA systems for the last several years and has made several changes in operator training and is examining controller certification. Further, OPS along with the pipeline industry has funded a research program examining human factors in pipeline control systems. These efforts are all welcome steps toward improving pipeline safety related to SCADA control of pipelines.

The Safety Board also recognizes the efforts made by various companies to improve safety on their pipelines. Many companies have included CPM in their SCADA systems to assist controllers in rapidly detecting abnormal situations on their lines.

Although efforts to deploy and update SCADA systems are underway, the Safety Board's review of SCADA systems in the hazardous liquid pipeline industry uncovered five areas for potential improvement: display graphics, alarm management, controller training, controller fatigue, and leak detection systems.

[75] National Transportation Safety Board, *Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota, July 4, 2002*, Pipeline Accident Report PAR-04/01 (Washington, DC: NTSB, 2004). See Appendix B for a summary of the Cohasset accident.

## SCADA Display Graphics

Since its inception in the late 1960s, SCADA has evolved in many areas, but none is as extensive as the use of graphics in the SCADA controller interface. Early displays used monochromatic cathode ray tubes (CRT) with line printers connected to the system. These systems used symbols, such as asterisks, to warn controllers of a potential problem. Early systems represented the pipeline based upon the organization of computing hardware, rather than the configuration of the pipeline itself.

As computer graphics capabilities improved, however, SCADA designs evolved from coded depictions of computer hardware to depictions of pipeline schematics. Current SCADA systems are a mix of tabular and schematic displays. However, one company in the survey presented data in a display that integrated input and output volumes on a pipeline segment into one display, enabling its controllers to identify leaks quickly. The use of such integrated displays has become commonplace in many types of control systems, including those used in the nuclear power and aviation industries.

The Safety Board has advocated graphical standards for computerized control systems since the Brenham storage cavern accident, which occurred in 1992. The Board's recommendation for graphical standards (P-93-22) prompted the API to establish a graphics committee under the cybernetics working group to establish recommended practices for the use of graphics for SCADA interfaces.

The graphics committee began its task in 2001 by reviewing the systems in place at their respective companies. Each company represented on the committee submitted sample SCADA screens. Recognizing the wide diversity among the various systems graphically, the group began looking for acceptable rules for SCADA system graphic design. On July 27, 2005, the committee released a draft of its SCADA Display Recommended Practice 1165 for review.

The use of graphics standards in other industries is widespread. The Nuclear Regulatory Commission published guidelines for the use of human factors in display design in its *Human-System Interface Design Review Guidelines*.[76] The FAA has published human factors guidelines for display design.[77] The power industry has also developed standards in the *Fossil Fuel Power Plant Human-Machine Interface—CRT Displays*.[78] The development of these guidelines has improved the clarity of displays that operators use in control systems. As noted in chapter 4, the Safety Board noted many displays in its review that did not follow widely accepted human factors design guidelines

[76] U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Research, Energy Sciences and Technology Department, Brookhaven National Laboratory, *Human-System Interface Design Review Guidelines* NUREG-0700, Rev.2 (Upton, New York: NRC, 2002).

[77] Department of Transportation, Federal Aviation Administration, *Human Factors Design Guide for Acquisition of Commercial-Off-the-Shelf Subsystems, Non-Developmental Items, and Developmental Systems*, DOT/FAA/CT-96/01 (Atlantic City International Airport, NJ: William J. Hughes Technical Center, 1996).

[78] The Instrumentation, Systems, and Automation Society, *Fossil Fuel Power Plant Human-Machine Interface—CRT Displays,* ISA-TR77.60.04-1996 (Research Triangle Park: NC, 1996).

for various industry applications. The issues identified included poor contrast between foreground colors and background colors; overuse of colors; displays that were not colorblind friendly; and cluttered displays. The API has released draft guidelines that address the display concerns raised above, including the need for coding of color information for colorblind controllers. Absent the presence of good guidelines, some systems are going to be poorly designed, thereby hindering a controller's ability to detect a leak. Accordingly, the Board concludes that implementation of graphical standards developed for pipeline operations will increase the likelihood that leaks will be detected and that resulting damage from the leaks will be minimized. Therefore, the Safety Board recommends that OPS require operators of hazardous liquid pipelines to follow the American Petroleum Institute's Recommended Practice 1165 for the use of graphics on the SCADA screens.

## Alarm Philosophy

A key element of the SCADA system display is the alarms that indicate changes along the pipeline. All of the SCADA systems examined in the study use auditory and visual indications to make the alarms more noticeable. During site visits, controllers were asked what they believed to be the most important aspect of the SCADA system for preventing incidents. Most—9 of 12—included alarms in their responses. Nearly all controllers listed the alarm page as one of the screens they used in diagnosing abnormal operating conditions.

Alarms that indicate abnormal conditions along the pipeline must be designed to convey their meaning clearly to the controller. Poorly designed alarms can be difficult to interpret, leading the controller to take actions inappropriate to the actual situation. The importance of alarms in helping controllers understand leaks cannot be overstated. In the Gramercy accident, the line balance alarm indicated that more liquid was entering the pipeline than was being delivered. This alarm occurred 11 seconds after one alarm and 4 seconds before another. In the midst of this quick succession of alarms, the controller failed to read the text of the line balance alarm completely and misinterpreted the alarm. When another line balance alarm occurred 1 hour later, its isolation from other alarms allowed the controller to detect and react to the alarm. In several other accidents, controllers also misunderstood alarms or no alarms were available. In the Winchester accident, for example, the leak detection alarm first alerted the controllers almost 2 hours before they shut down the line. In the Chalk Point accident, controllers were unable to monitor the pipeline through the SCADA system because the system was not designed to monitor the pipeline during cleaning operations. Had a SCADA system been available, the Chalk Point controllers might have detected the leak more quickly.

Alarms are important for directing a controller's attention; however, alarming potential leak events too often can be distracting. The system designer sets the threshold for an alarm so that virtually no true alarm conditions will fail to set off an alarm. The result is that occasional alarms occur when no true alarm exists (a false alarm). Although SCADA system designers may not view a single false alarm as a problem, multiple false alarms may be. If a controller responds to a false leak alarm, the economic cost of shutting down the line is small compared with the possibility of spilling a large amount of product. However, as the number of false alarms increases, so does the cost of responding to all of them. Controllers may try to differentiate false alarms from true alarms and respond only to the latter. As a result, they may miss a true alarm, increasing the severity of a product leak. In the Gramercy accident, the controller commented that he always saw certain leak alarms when he adjusted the line segment he was working on. In the Kingman accident, the controller stated that, after seeing the rate of change alarm for pipeline pressure, he was waiting for pressure to return to normal as it had in the past.

One way to ensure controller attention to critical alarms is to prioritize them. The Human Factors Design Standard (HFDS)[79] produced by the Federal Aviation Administration states that "alarms should be automatically organized and presented to the users in a prioritized manner." Alarms that would indicate an immediate action, such as indicators of potential product loss, should override all alarms and require immediate action by a controller. Prioritized alarms would help controllers recognize which alarms can wait and which require immediate attention and action. More than 25 percent of the companies surveyed currently do not prioritize alarms. As a result, controllers may be receiving unnecessary alarms that result in lower vigilance to all alarms.

In addition to being prioritized, alarms can be suppressed when a controller knows the information that the alarm provides, such as an alarm that indicates an increase in flow following a pipeline startup. Controllers then have fewer alarms to read but can later check for alarms that were suppressed in the alarm log. Alarms that could be suppressed include repetitive alarms and alarms that signal situations of which the controller is aware, alarms that are the result of equipment being out of service, or multiple alarms that are related to one fault.[80]

An oil company presented its strategy for alarm management at the *2002 Pipeline and Cybernetics Conference* sponsored by the API.[81] The company reported performing periodic reviews to remove unnecessary alarms and properly define all alarm settings. They also reported training controllers to deal with a burst of alarms that can occur with a system leak. The company reported dividing its alarms into three categories: priority three alarms, which signify notices of normal operations that may not require any action on the part of the controller; priority two alarms, which signify a device in trouble or a significant critical operation alert and for which the response would be based upon the controller's training; and priority one alarms, which protect against product containment or are for regulatory compliance. For priority one alarms, controller action is required as is documentation of the action.

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[79] Department of Transportation, Federal Aviation Administration, *Human Factors Design Standard*, DOT/FAA/HF-STD-001 (Atlantic City International Airport, NJ: William J. Hughes Technical Center, 2003).

[80] D. Bailey and E. Wright, *Practical SCADA for Industry* (London, England: IDC Technologies Inc., 2003).

[81] *2002 Pipeline and Cybernetics Conference*, American Petroleum Institute, Houston, Texas, April 21-23, 2002.

In addition to prioritizing and suppressing alarms, SCADA managers need to work with controllers to ensure that the meaning of each alarm is unambiguous.[82] For example, in one site visit the controller noted that alarms were labeled with codes that were more for the SCADA manager to use in diagnosing SCADA software than for controllers to use to understand a problem on the pipeline. Designing alarms to be more meaningful would assist controllers in making accurate decisions.

Ensuring that alarms do not occur too frequently and are understood by controllers requires the company to have an effective alarms audit system. "It is important to continuously audit, maintain and improve the alarm system through analysis and review with the operators on the performance of the system."[83] Following the Gramercy accident, the Safety Board recommended that the company:

> Evaluate the effectiveness of alternative display formats and frequencies of alarming critical information for your supervisory control and data acquisition system and modify the system as necessary to ensure that controllers are specifically prompted to consider the possibility of leaks during system deviations that are consistent with a loss of product from a pipeline. (P-98-22)

As a result of its review of leak alarms, the company was able to reduce the number of leak alarms from 150 to 200 a day down to 60 per day. The Safety Board classified recommendation P-98-22 as "Closed—Acceptable Action."

In the Safety Board's survey, 26 of the 78 control centers that responded to the survey reported having no plan in place for reviewing/auditing alarms. Each control center should have a review/audit policy with regular review intervals to ensure that controllers are appropriately responsive to each alarm they receive. The Safety Board concludes that an effective alarm review/audit system will increase the likelihood of controllers appropriately responding to alarms associated with pipeline leaks. Therefore, the Safety Board recommends that the Office of Pipeline Safety require pipeline companies to have a policy for the review/audit of alarms.

## Training and Selection

Pipeline controllers are primarily trained on the job. As such, controllers become very proficient at handling the day-to-day operations of a pipeline system. However, the training of infrequent events, such as leak detection and mitigation, must be learned from methods other than on-the-job training. In addition, although it is optimal to have controllers shut down a pipeline as soon as a leak occurs, oftentimes the evidence of a leak is ambiguous. This ambiguity leads controllers to call in others to help decide if a leak has occurred.

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[82] C.E. Billings, *Human-Centered Aviation Automation: Principles and Guidelines*. Moffett Field, California, National Aeronautics and Space Administration, Ames Research Center (1996).

[83] D. Bailey and E. Wright, *Practical SCADA for Industry*, London, England: IDC Technologies Inc. (2003).

The issues of controller training, selection, and qualification have been noted in six of the SCADA-related accidents the Safety Board investigated. For example, in the Fork Shoals accident, the Board noted that the "training provided by the operator to its pipeline controllers and shift supervisors before the accident was inadequate to prepare them to respond properly and in a timely fashion to abnormal conditions and pipeline emergencies." Likewise, in the Gramercy accident, the Board recommended that the operator use recurrent pipeline controller training to increase controller proficiency in interpreting and responding to control system data that may indicate a system leak.[84] In both accidents, controllers misunderstood SCADA indications of a leak and failed to respond quickly.

Following the Winchester, Kentucky, accident, the operator indicated that the company was in the process of incorporating a training simulator into its training program so that controllers could experience simulated leaks on the pipeline. In a similar manner, the pipeline operator in the Knoxville, Tennessee, accident planned to incorporate data from the accident into its simulator to better train controllers in leak recognition and response.

In 1987, following two gas pipeline accidents, the Safety Board issued Safety Recommendation P-87-2, asking RSPA to require that operators of pipelines develop and conduct selection, training, and testing programs to annually qualify employees. In 1998, the Safety Board classified the recommendation "Closed—Unacceptable Action" because RSPA had failed to conduct the required rulemaking. In 1997, following an accident in San Juan, Puerto Rico,[85] the Safety Board issued Safety Recommendation P-97-7, asking RSPA to complete a final rule on employee qualification training and testing standards within 1 year, to require operators to test employees on the safety procedures they are expected to follow, and to demonstrate that employees can correctly perform the work.

RSPA issued a Notice of Proposed Rulemaking in October 1998, and in January 1999, the Safety Board commented on it, noting that the proposed rule failed to adequately address qualification requirements or include requirements for training and testing. The final rule, issued in April 2001, allowed controllers to be evaluated by written or oral examinations, observation during on-the-job performance, or work history. After October 28, 2002, operators were not allowed to use work history as an evaluation measure and were required to use another method at the next evaluation, such as a written test. However, the rule allowed operators to determine the interval between evaluations. It was therefore conceivable that a pipeline employee might indefinitely continue to perform safety-related tasks based solely on work history. Accordingly, the Board closed Safety Recommendation P-97-7, unacceptable action, noting that the rule failed to address the importance of testing the controller at regular intervals.

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[84] The Gramercy recommendation on training, P-98-21, was classified "Closed—Acceptable Action" on April 28, 1999.

[85] National Transportation Safety Board, *San Juan Gas Company, Inc./ENRON Corp., Propane Gas Explosion in San Juan, Puerto Rico, on November 21, 1996,* Pipeline Accident Report NTSB/PAR-97/01 (Washington, DC: NTSB, 1997).

On March 3, 2005, in response to the *Pipeline Safety Improvement Act of 2002,* OPS promulgated additional regulations for qualification of pipeline controllers. These regulations restricted operators from using observation of on-the-job performance as the sole method of evaluation and required operators to provide appropriate training to ensure that individuals performing covered tasks had the necessary knowledge and skills to perform the tasks.

On April 15, 2005, in response to the *Pipeline Safety Improvement Act of 2002*, OPS also published a request for control centers to participate in their pilot program on controller certification. The three centers for the study have been selected and the OPS study team has begun regular meetings with these participants. The team is on schedule to deliver a report to Congress by December 2006.

In addition to the rulemaking actions described above, industry has taken steps to improve controller training and qualification. For example, the American Society of Mechanical Engineers (ASME) is creating a standard for qualifying pipeline personnel. The ASME B31Q committee, which is charged with developing the new pipeline operator qualification standard, is currently reviewing comments on the draft version, which was available for public comment on February 2, 2005. The committee identified nine tasks for ensuring that pipeline controllers are qualified. Training tasks related to leak detection are to "monitor system operation including monitoring for pipeline leaks" and to "recognize and react to abnormal situations."

As of November 30, 2004, RSPA responsibilities regarding the implementation of pipeline controller training were transferred to the Pipeline and Hazardous Materials Safety Administration (PHMSA). Changes currently being implemented by PHMSA and ASME to shape the qualification and training of controllers have been suggested by the Safety Board for 20 years. The Safety Board recognizes that, although overdue, these actions are a positive step toward achieving pipeline safety objectives.

Several training coordinators interviewed during the study also highlighted ongoing activities at their companies to improve controller training, including the use of simulators. Two trainers commented on their efforts to incorporate simulators into their training. At the time of the Safety Board's survey, only 23 of the 91 control centers reported having simulators. Training coordinators also mentioned that using leak detection tools and trend screens are an aspect of training that controllers have the most difficulty understanding.

During the course of the study, the Safety Board found that lessons learned in other industries could be applied to SCADA systems in the pipeline industry, particularly in regard to the development of more realistic training. Following the power outage of August 14, 2003, for example, the North American Electrical Reliability Council[86] found that operators using SCADA systems to monitor the status of the electric grid were not adequately prepared to deal with the abnormal operations that occurred on that day. The

[86] *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, U.S.-Canada Power System Outage Task Force, April 5, 2004.

SCADA controllers on the electric grid were trained on the job, just as pipeline controllers were often trained. The Council concluded that controllers need improved training for abnormal operations, including simulations of abnormal operation either on computer or as tabletop drills.

Pipeline training coordinators who used simulators for training reported that the simulators were invaluable for leak detection training. In contrast, they found on-the-job training for leak detection to be difficult because such events are rare and may not occur during training. Coordinators stated further that oral or written tests might not be the most effective means of training controllers to recognize leak events. The Safety Board concludes that requiring controllers to train for leak detection tasks using simulators or non-computerized simulations will improve the probability of controllers finding and mitigating pipeline leaks. Therefore, the Safety Board recommends that the Office of Pipeline Safety require controller training to include simulator or non-computerized simulations for controller recognition of abnormal operating conditions, in particular, leak events.

Another aspect of training not addressed in controller qualification work to date is an examination of how teamwork affects control center operations. In the Winchester accident, the controller, a supervisor, and a field technician were involved in diagnosing the potential leak. The controller had shut down the line in response to data indications from the SCADA system, which included an alarm indicating a possible leak. After consultation with his supervisor, the controller restarted the line. After several more leak alarms, the supervisor directed the controller to shut down the line. The situation that occurred in the Winchester accident was not unique. In six of the ten accidents discussed as having SCADA issues in chapter one, team decision-making was involved in deciding to shut down a pipeline. In five of these cases, decisions to restart a line that had correctly been shut down by the controller resulted in greater loss of product.

The Safety Board is aware of one company in the pipeline industry that has emphasized the teamwork aspect of decision-making in its training. The company in the Winchester accident has developed a decision aid and training to help its controllers diagnose an abnormal event. The “WIGO” tool that the company described at the Board’s Pipeline Safety Hearing gives the controller training and resources to help diagnose an event and call on others to help diagnose an event if needed.[87] In this training, teams are given a number of scenarios to evaluate to determine if team members are making correct decisions on facts about the event or are coming to conclusions without facts. In addition, controllers are trained that, before restarting the line, they must get concurrence from all team members that they agree that the line is safe to restart. The Board will be interested in monitoring the results of the WIGO program.

[87] Day two: Pipeline Safety Public Hearing

## Fatigue Management

Of the 18 controllers interviewed, 8 reported their work schedules as the general thing they most disliked about their jobs. When all 18 controllers were asked if there was anything they disliked about their work schedules, 10 indicated working the night shift or not getting enough sleep, particularly when their shifts changed from day to night or night to day. Eleven of the twelve companies visited by the Safety Board used rotating 12-hour shifts to control and monitor pipelines. At one company, a controller monitored the pipeline during business hours, and the SCADA system alerted a receptionist or answering service, who informed the on-call controller when an alarm occurred.

Fatigue related to rotating 12-hour shifts has been examined in numerous studies. In a 1999 study,[88] researchers examined workers at a petrochemical plant and measured their alertness at three intervals (second, sixth, and tenth hour). They found that, according to subjective ratings, controllers working the night shifts were less alert in their tenth shift hour than during their second hour (a decrease from 8.1 to 5.1 on a 10-point scale). This decrease in alertness persisted through their three-night schedule. Conversely, their daytime counterparts were able to maintain alertness over their whole shift. In another study,[89] researchers found decreased performance (187 percent more errors) and increased sleepiness (66 percent) for workers of a 12-hour shift during their last 4 hours on shift. Also, workers on the 12-hour work schedule reported reductions in the amount of sleep and its quality. When the same workers were retested 3.5 years later,[90] subjects working the 12-hour shift still showed decreased performance on a number of cognitive tasks and less quality sleep than their 8-hour shift counterparts.

Among the companies visited, the Safety Board found that the rotation between night and day shifts varied widely. One company used a monthly rotation with controllers on day shifts for a month followed by night shifts for a month. Another company used 4 day shifts followed by 4 night shifts.

Rotating controllers from day to night shifts was discussed in the Safety Board's Fork Shoals accident report.[91] That controller had worked during the day on his last shift and had just moved to the night shift. Such inversions of schedule can increase fatigue. In addition, the controller had been awake for 17 hours when the accident occurred. Following the Fork Shoals accident, the Safety Board recommended that RSPA assess the potential safety risks associated with rotating pipeline controller shifts and provide

[88] F.M. Fischer, C.R.C. Moreno, F.N.S. Borges, and F.M. Louzada, "Alertness and Sleep after 12 Hour Shifts: Differences Between Day and Night Shift Work," *Proceedings, XIV International Symposium on Night and Shiftwork*, September 13-17, 1999.

[89] R.R. Rosa, M.J. Colligan, and P. Lewis, "Extended Workdays: Effects of 8-Hour and 12-Hour Rotating Shift Schedules on Performance, Subjective Alertness, Sleep Patterns, and Psychosocial Variables," *Work and Stress* 3(1) (1989) 21-32.

[90] R.R. Rosa, "Performance, Alertness, and Sleep After 3.5 Years of 12 Hour Shifts: A Follow-Up Study," *Work and Stress* 5(2) (1991) 106-116.

[91] NTSB/PAR-98/01.

guidelines for controller work schedules that reduce the likelihood of accidents attributable to controller fatigue (P-98-30).

The Safety Board also issued Safety Recommendation P-99-12 to RSPA as a result of its safety report, *Evaluation of U.S. Department of Transportation Efforts in the 1990s to Address Operator Fatigue*.[92] The recommendation asked RSPA, within 2 years, to establish scientifically based hours-of-service regulations that set limits on hours of service, provided predictable work and rest schedules, and considered circadian rhythms and human sleep and rest requirements. Both pipeline fatigue recommendations are on the Safety Board's Federal Most Wanted List.

In response to both recommendations, RSPA stated in 2000 that it was trying to determine the role of fatigue in pipeline accidents and that it was considering an advisory bulletin on the issue of controller fatigue. RSPA stated that it had also examined its accident database for the prevalence of controller fatigue in pipeline accident reports. After analyzing the database, RSPA stated that fatigue was not a factor in pipeline accidents although it should be noted that items related to fatigue, such as controller work schedules, were not available in the dataset.

PHMSA, which has assumed responsibility for Safety Recommendation P-98-30, has initiated another study on fatigue to address the recommendations.[93] In 2004, Batelle Memorial Institute was awarded a contract to conduct research on human factors in the pipeline control room. The research plan includes an examination of fatigue in the control room and will examine multiple pipeline companies.

OPS developed an advisory bulletin, *Pipeline Safety: Countermeasures to Prevent Human Fatigue in the Control Room* (FR Doc. 05–15956), on rotating schedules for the pipeline industry. The bulletin suggests that companies achieve the following: develop shift rotation practices that minimize fatigue, limit controllers to 12-hour shifts unless extraordinary or emergency situations are involved, document cases where controllers have to work longer than 12 hours in a shift, ensure that controllers get 10 hours of rest between shifts, and develop guidelines for scheduling controllers that consider the effects of fatigue. In addition, the bulletin includes suggestions for training controllers and supervisors about fatigue and ensuring that the control room environment does not induce fatigue. To ensure that companies do not take advantage of extraordinary or emergency situations, the Safety Board expects that OPS will examine documentation of these circumstances to determine if the situations are truly extraordinary. Giving companies information about the risks of fatigue will benefit controllers who already report issues with fatigue. The issuance of this bulletin on August 11, 2005, is a positive step toward reducing fatigue in pipeline controllers. However, the Board is concerned that, despite the issuance of an advisory bulletin, some operators will continue to operate shifts conducive to fatiguing controllers.

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[92] National Transportation Safety Board, *Evaluation of U.S. Department of Transportation Efforts in the 1990s to Address Operator Fatigue,* Safety Report NTSB/SR-99/01 (Washington, DC: NTSB, 1999).

[93] RSPA had previously begun a study with Volpe to address fatigue in pipeline operations; however, the Volpe study was discontinued early in the research.

The Safety Board also found that most controllers interviewed expressed concern about the length and rotation of work schedules including their difficulties in getting enough sleep or the fatigue they felt while working night shifts. Despite the large percentage of controllers expressing fatigue issues related to shift work, the effect of this fatigue cannot be ascertained from currently collected accident data. The Safety Board concludes that because the report form used by the Office of Pipeline Safety for companies to report liquid pipeline accidents (PHMSA F 7000-1) does not require operators to provide information about fatigue, such as controller work schedules, it is not possible to empirically determine the contribution of fatigue to pipeline accidents using the Office of Pipeline Safety accident database. Therefore, the Safety Board recommends that the Office of Pipeline Safety change the liquid accident reporting form (PHMSA F 7000-1) and require operators to provide data related to controller fatigue. Possible items to be added to the accident report form could include the time a controller had been on duty, the time a controller had been awake prior to the accident, the detection time of the accident, the time the leak is estimated to have begun, and whether the controller changed from day to night shift (or night to day) in the previous 2 days.

The collection of data about fatigue on a revised hazardous liquid reporting form combined with the research underway to understand human fatigue in pipeline operations being funded by OPS and industry will provide a good estimate of the effects of the fatigue controllers report on the performance of their duties. The issuance of the fatigue bulletin is a good first step to mitigating the effects of fatigue on controllers. The Safety Board will monitor the outcomes of the OPS-funded fatigue research and the outcome the research produces.

## Computational Pipeline Monitoring

Improving leak detection was a primary focus of the Safety Board's public hearing on pipeline safety. In the regulations for pipeline integrity management, the OPS requires pipeline operators to take steps to prevent and mitigate the consequences of a pipeline failure that can affect a high consequence area. Operators are required to conduct a risk analysis of pipeline segments to identify additional actions that would enhance public safety or environmental protection. Operators are also required to have a means to detect leaks, evaluate the capability of the leak detection system, and modify it as necessary to protect any high consequence areas. However, the regulations stop short of mandating computer-based leak detection systems[94] in high consequence areas. In the *Pipeline Safety Improvement Act of 2002*, Congress required OPS to conduct research on leak detection systems, emphasizing the detection of small leaks.

Twelve of the twenty-eight pipeline systems that had leaks above 50,000 gallons had no computer-based leak detection in place. For the 16 systems that did have leak detection in place, 6 leaks were first detected by the leak detection system. Third parties

[94] Computer-based leak detection systems include CPM systems and systems that detect the presence of a leak using a sensor that detects a product release and then sends an alarm to the operator.

detected two leaks on pipelines with leak detection systems and five leaks on pipelines without leak detection.

In the Safety Board's survey of pipeline control centers, 58.5 percent of the companies reported that their SCADA systems included leak detection functions. Of all companies reporting, 37.2 percent had leak detection software embedded in their SCADA systems and 24.4 percent reported that they used a separate leak detection computer program. More than half of these companies reported that they had in the past detected a leak with their leak detection systems.

Although computer-based leak detection systems are not required for all liquid pipelines in the United States, some regulatory agencies have taken that step. In Washington State, following the Bellingham accident, companies were required by State regulation to be able to locate leaks of 8 percent maximum flow within 15 minutes or less. In addition, Canada requires companies to develop and implement pipeline control systems that include "a leak detection system that, for oil pipelines, meets the requirements of CSA Z662[95] and reflects the level of complexity of the pipeline, the pipeline operation and the products transported." Germany also currently requires computerized leak detection on its hazardous liquids pipelines.

One concern with CPM is that the systems are unable to detect small leaks with great accuracy. However, the technology is improving and the ability of current leak detection systems to detect small leaks is currently being studied in congressionally mandated research funded by OPS. Further, CPM systems can be effective in rapidly detecting major pipeline ruptures that require controllers to act quickly to limit the consequences of these spills. The data from the accidents from 2002–2004 show that leak detection systems can be effective in large spills. The Safety Board has also documented accidents in which CPM systems detected spills quickly: Cohasset (3 minutes), Gramercy (3 minutes), Winchester (1 minute), and Bellingham (13 minutes).[96]

The Safety Board also recognizes that "one size fits all" does not work for all pipelines. However, the many CPM methods that exist each have their strengths and weaknesses. The Safety Board concludes that ensuring constant monitoring of an entire pipeline using a computer-based leak detection technology would enhance the controller's ability to detect large spills, increase the likelihood of spill detection, and reduce the response time to large spills. Therefore, the Safety Board recommends that the Office of Pipeline Safety require operators to install computer-based leak detection systems on all lines unless engineering analysis determines that such a system is not necessary.

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[95] The regulation appears in Onshore Pipeline Regulations 37(c) 1999. The Canadian Standard Association Z662 addresses oil and gas pipeline regulations in Canada.

[96] NTSB-PAR-04-01, NTSB-PAB-01-02, NTSB-PAR-02-02, and NTSB-PAB-98-01.

# Conclusions

1. Most hazardous liquid pipeline operators use SCADA systems to monitor and control their pipelines.

2. Operators reported that SCADA systems enhance both the safety and efficiency of pipeline operations.

3. Implementation of graphical standards developed for pipeline operations will increase the likelihood that leaks will be detected quickly and that resulting damage from the leaks will be minimized.

4. An effective alarm review/audit system will increase the likelihood of controllers appropriately responding to alarms associated with pipeline leaks.

5. Requiring controllers to train for leak detection tasks using simulators or non-computerized simulations will improve the probability of controllers finding and mitigating pipeline leaks.

6. Because the report form used by the Office of Pipeline Safety for companies to report liquid pipeline accidents (PHMSA F 7000-1) does not require operators to provide information about fatigue, such as controller work schedules, it is not possible to empirically determine the contribution of fatigue to pipeline accidents using the Office of Pipeline Safety accident database.

7. Ensuring constant monitoring of an entire pipeline using a computer-based leak detection technology would enhance the controller's ability to detect large spills, increase the likelihood of spill detection, and reduce the response time to large spills.

# Recommendations

As a result of this safety study, the National Transportation Safety Board makes the following safety recommendations to the Pipeline and Hazardous Materials Safety Administration:

> Require operators of hazardous liquid pipelines to follow the American Petroleum Institute's Recommended Practice 1165 for the use of graphics on the Supervisory Control and Data Acquisition screens. (P-05-1)
>
> Require pipeline companies to have a policy for the review/audit of alarms. (P-05-2)
>
> Require controller training to include simulator or non-computerized simulations for controller recognition of abnormal operating conditions, in particular, leak events. (P-05-3)
>
> Change the liquid accident reporting form (PHMSA F 7000-1) and require operators to provide data related to controller fatigue. (P-05-4)
>
> Require operators to install computer-based leak detection systems on all lines unless engineering analysis determines that such a system is not necessary. (P-05-5)

## BY THE NATIONAL TRANSPORTATION SAFETY BOARD

**MARK V. ROSENKER**
Acting Chairman

**ELLEN ENGLEMAN CONNERS**
Member

**DEBORAH A. P. HERSMAN**
Member

**Adopted: November 29, 2005**

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# Appendix A

## SCADA Related Recommendations

**SCADA Related Recommendations**

| | | | | |
|---|---|---|---|---|
| P-71-001 | P-71-001 | P-0005 | THE NTSB RECOMMENDS THAT THE OFFICE OF PIPELINE SAFETY OF THE DEPARTMENT OF TRANSPORTATION: CONDUCT A STUDY TO DEVELOP STANDARDS FOR THE RAPID SHUTDOWN OF FAILED NATURAL GAS PIPELINES AND WORK IN CONJUNCTION WITH THE FEDERAL RAILROAD ADMINISTRATION TO DEVELOP SIMILAR STANDARDS FOR LIQUID PIPELINES. | CAA |
| P-72-002 | P-72-002 | P-0011 | THE NTSB RECOMMENDS THAT: THE FEDERAL RAILROAD ADMINISTRATION UNDERTAKE A STUDY OF THE CURRENT METERING PRACTICES IN THE LIQUID PIPELINE INDUSTRY, WITH THE POSSIBLE ASSISTANCE OF QUALIFIED PIPELINE GROUPS, TO DETERMINE THE EXISTING STATE OF THE ART IN DETECTING SMALL PITHOLE-TYPE LEAKAGE BY METER VARIANCE WITH PARTICULAR REGARD TO LARGE DIAMETER PIPELINES OPERATING AT HIGH VOLUMES. THE STUDY SHOULD INCLUDE THOSE PIPELINES WHOSE PUMPING OPERATIONS ARE REGULATED BY THE USE OF RECORDING METERS WHICH MONITOR THE RECEIPTS AND DELIVERIES AND ARE SET TO SHUT DOWN OR OTHERWISE INFORM THE PIPELINE DISPATCHER UPON THE OCCURRENCE OF A SPECIFIED AMOUNT OF INPUT/OUTPUT VARIANCE. THE STUDY SHOULD INCLUDE METER ACCURACIES WITH THE INTENT TO ESTABLISH CERTAIN MINIMUM STANDARDS REGARDING RECEIPT AND DELIVERY VARIANCES WITHIN WHICH LIQUID PIPELINES SHALL OPERATE. BASED UPON THE RESULTS OF THIS STUDY, THE NUMBER OF BARRELS-PER-HOUR VARIANCE ALLOWABLE BETWEEN THE INPUT AND OUTPUT OF LIQUID PETROLEUM PIPELINES SHOULD BE INCLUDED IN 49 CFR 195. | CR |
| P-72-010 | P-72-010 | P-0012 | THE NTSB RECOMMENDS THAT: THE FEDERAL RAILROAD ADMINISTRATION OF THE DEPARTMENT OF TRANSPORTATION CONDUCT A STUDY, IN COOPERATION WITH SOURCE OF QUALIFIED PIPELINE EXPERTISE, CONCERNING MINIMUM VALVE SPACING STANDARDS AND THE USE OF REMOTELY OPERATED VALVES, AUTOMATICALLY OPERATED VALVES, AND CHECK VALVES ON ALL LIQUEFIED PETROLEUM PIPELINES. AS AN ADJUNCT TO THIS, THE SAFETY BOARD INVITES ATTENTION TO A RECOMMENDATION MADE IN ITS SPECIAL STUDY OF "EFFECTS OF DELAY IN SHUTTING DOWN FAILED PIPELINE SYSTEMS AND METHODS OF PROVIDING RAPID SHUTDOWN. | CAA |
| P-72-012 | P-72-012 | P-0012A | THE NTSB RECOMMENDS THAT THE PHILLIPS PIPE LINE COMPANY: MAINTAIN AS A MAXIMUM, THE REDUCED PUMPING PRESSURES RECOMMENDED BY THE NATIONAL TRANSPORTATION SAFETY BOARD'S SAFETY RECOMMENDATION P-71-6 ISSUED APRIL 27, 1971, WHICH LIMITS TO 900 P.S.I.G. THE MAXIMUM DISCHARGE PRESSURES AT EACH OF THE PUMP STATIONS BETWEEN BORGER AND EAST ST. LOUIS, AS WELL AS PHILLIP'S OWN PRESSURE LIMITATION OF 900 P.S.I.G. ON THE FOUR PUMP STATIONS IN THE AFFECTED AREA; SYRACUSE, JEFFERSON CITY, ROSEBUD, AND VILLA RIDGE. A 24-HOUR HYDROSTATIC PRESSURE TEST EQUAL TO 125 PERCENT OF THE MAXIMUM ANTICIPATED PRESSURE AS SPECIFIED IN THE CFR TITLE 49 PART 195 WOULD BE REQUIRED BEFORE THIS LINE PRESSURE COULD BE AGAIN INCREASED. | CNLA |

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| P-72-013 | | P-72-013 | P-0012A | THE NTSB RECOMMENDS THAT THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS GAS PIPING STANDARDS COMMITTEE: DEVELOP GUIDELINES FOR THE USE OF SYSTEMS ANALYSIS BY GAS DISTRIBUTION AND GAS TRANSMISSION PIPELINE OPERATORS. THESE GUIDELINES SHOULD SERVE A SIMILAR FUNCTION FOR GAS PIPELINE SYSTEMS AS THE MILITARY STANDARD, REQUIREMENTS FOR SYSTEM SAFETY PROGRAM FOR SYSTEMS AND ASSOCIATED SUBSYSTEMS AND EQUIPMENT (MIL-STD-882), DOES FOR MILITARY SYSTEMS. THESE GUIDELINES SHOULD COVER THE FULL LIFE CYCLE OF A GAS PIPELINE SYSTEM AND BE APPLICABLE TO THE DESIGN OF NEW PIPELINES AS WELL AS TO THE OPERATION AND MAINTENANCE OF EXISTING PIPELINES. THIS WORK SHOULD BE UNDERTAKEN WITH THE COOPERATION OF THE AMERICAN GAS ASSOCIATION. | CNLA |
| P-72-043 | ? | P-72-043 | P-0016 | THE NTSB RECOMMENDS THAT: THE OFFICE OF PIPELINE SAFETY AMEND 49 CFR 192 TO REQUIRE THAT EACH PIPELINE OPERATOR HAVE ON DUTY A SUFFICIENT NUMBER OF DISPATCHING PERSONNEL TO EFFECTIVELY COORDINATE EMERGENCY SITUATIONS, A STUDY MAY BE REQUIRED TO DETERMINE THE RELATIONSHIP BETWEEN VARIOUS CONDITIONS AND THE NUMBER OF DISPATCHERS NECESSARY. | CAAA |
| P-72-060 | | P-72-060 | P-0016 | THE NTSB RECOMMENDS THAT: THE WASHINGTON GAS LIGHT COMPANY REALIGN ITS DISPATCHING FACILITIES SO THAT ONE DISPATCHER CAN CONTACT ALL FIELD PERSONNEL CAPABLE OF RESPONDING TO AN EMERGENCY WHEN SUCH A SITUATION IS ENCOUNTERED. | CAAA |
| P-73-030 | | P-73-030 | P-0021 | THE NTSB RECOMMENDS THAT THE OFFICE OF PIPELINE SAFETY OF THE DEPARTMENT OF TRANSPORTATION: AMEND THE 49 CFR 195.408, COMMUNICATIONS, TO DESCRIBE MORE FULLY THE TYPE OF INFORMATION REQUIRED FOR THE SAFE OPERATIN OF PIPELINES AND THE CONDITIONS UNDER WHICH THIS INFORMATION SHOULD BE TRANSMITTED REMOTELY. | CUA |
| P-73-032 | | P-73-032 | P-0021 | THE NTSB RECOMMENDS THAT THE EXXON PIPE LINE COMPANY: INSTALL FACILITIES CAPABLE OF REMOTELY TRANSMITTING THE CONTINUOUS RECORDING PRESSURES FROM THE COMYN AND HEARNE PUMP STATIONS TO THE CENTRAL DISPATCHING OFFICE. | CNLA |
| P-73-033 | | P-73-033 | P-0021 | THE NTSB RECOMMENDS THAT THE EXXON PIPE LINE COMPANY: INSTRUCT THE DISPATCHERS TO MONITOR CAREFULLY THOSE LINES WHICH ARE CLOSED-IN AND INOPERATIVE TO PRECLUDE THE POSSIBILITY OF OVERPRESSURE. | CNLA |
| P-74-016 | | P-74-016 | P-0026 | THE NTSB RECOMMENDS THAT THE OFFICE OF PIPELINE SAFETY OF THE DEPARTMENT OF TRANSPORTATION: REVISE 49,CFR 192.741 TO REQUIRE PIPELINE OPERATORS TO TELEMETER GAS PRESSURE OR FLOW DATA IN SUCH A WAY AS TO INSURE PROMPT WARNINGS OF SIGNIFICANT SYSTEM FAILUR | CNLA |
| P-74-019 | | P-74-019 | P-0026 | THE NTSB RECOMMENDS THAT THE AMERICAN SOCIETY OF MECHANICAL ENGINEERS GAS PIPING STANDARDS COMMITTEE: DEVELOP GUIDELINES FOR THE USE OF TELEMETERING ON GAS DISTRIBUTION SYSTEMS SO THAT SYSTEM FAILURES CAN BE PROMPTLY DETECTED. | CAA |
| P-74-022 | | P-74-022 | P-0026 | THE NTSB RECOMMENDS THAT THE MISSOURI PUBLIC SERVICE COMPANY: INSTALL TELEMETERING EQUIPMENT AT THE CLINTON AND OTHER TOWN BORDER STATIONS, SO THAT SYSTEM FAILURES CAN BE PROMPTLY DETECTED. | CAA |
| P-74-050 | | P-74-050 | P-0030 | THE NTSB RECOMMENDS THAT THE OFFICE OF PIPELINE SAFETY OF THE DEPARTMENT OF TRANSPORTATION: IN ITS UPCOMING RULEMAKING ACTION FOR THE TRANSPORTATION OF HIGHLY VOLATILE, TOXIC, OR CORROSIVE LIQUIDS, INCLUDE ANHYDROUS AMMONIA PIPELINE SYSTEMS. PARTICULAR EMPHASIS SHOULD BE PLACED ON A REDUCTION OF THE MAXIMUM ALLOWABLE PRESSURES FOR NH3 SYSTEMS, MORE CLOSELY SPACED VALVES, AND MORE REMOTELY OR AUTOMATICALLY OPERATED VALVES. | CUA |

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| P-74-054 | | P-74-054 | P-0030 | THE NTSB RECOMMENDS THAT THE OFFICE OF PIPELINE SAFETY OF THE DEPARTMENT OF TRANSPORTATION REQUIRE THE MID AMERICA PIPE LINE COMPANY TO: INPROVE ITS CURRENT WRITTEN PROCEDURES UNDER 49 CFR SECTION 195.402, GENERAL REQUIREMENTS, TO REQUIRE THAT DISPATCHERS PERFORM DETAILED MONITORING OF ALL POINTS ON A PIPELINE SYSTEM DURING STARTUP UNTIL CONDITIONS HAVE STABILIZED. | CAA |
| P-75-008 | | P-75-008 | P-0033 | REVIEW THE USE, MAINTENANCE, AND TESTING OF FAILURE ALARMS ON GAS TRANSMISSION SYSTEMS AND AMEND 49 CFR 192 TO PROVIDE FOR IMPROVED WARNING OF PIPELINE FAILURES. | CUA |
| P-75-010 | ? | P-75-010 | P-0033 | REQUIRE TRANSCO TO: IF NECESSARY, REEVALUATE, AND REDESIGN THEIR COMPRESSOR STATION FAILURE ALARMS ON THE ENTIRE TRANSMISSION SYSTEM TO PREVENT A RECURRENCE OF THE EQUIPMENT FAILURE. | CAA |
| P-75-011 | ? | P-75-011 | P-0033 | REQUIRE TRANSCO TO: EXAMINE THE NECESSITY OF INSTALLING ADDITIONAL PIPELINE FAILURE ALARMS ON THE STATION RECORDING SUCTION AND DISCHARGE PRESSURE GAUGE, THE STATION RECORDING FUEL PRESSURE GAUGE, THE STATION FUEL FLOW GAUGE, OR THER OTHER PRESSURE-SENSITIVE POINTS. | CAA |
| P-76-039 | | P-76-039 | P-0052 | INITIATE NECESSARY EQUIPMENT CHANGES TO PROVIDE DATA NECESSARY FOR THE SAFE OPERATION OF THE PIPELINE CONTINUOUSLY TO THE DISPATCH CENTERS. | CNLA |
| P-77-030 | report end | P-77-030 | P-0088 | INCLUDE, IN EMERGENCY SHUTDOWN SYSTEMS, A SEPARATE CONTROL TO REMOTELY OPERATE VALVES THAT CAN INDEPENDENTLY BLOW DOWN THE STATION PIPING. | CNLA |
| P-78-005 | | P-78-005 | P-0093 | INVESTIGATE THE FEASIBILITY OF DETECTING PIPELINE LEAKS BY THE USE OF ELECTRONIC IN/OUT FLOW MONITORS OR OTHER LEAK DETECTION DEVICES, AND INSTALL ONE CAPABLE OF DETECTING BOTH SMALL AND LARGE LEAKS. | CAA |
| P-78-006 | | P-78-006 | P-0093 | ESTABLISH A CONTROL CENTER FOR THE LIQUID PROPANE PIPELINE AND TELEMETER ALL PRESSURE, FLOW, AND OTHER PERTINENT DATA NECESSARY FOR THE SAFE OPERATION OF THIS PIPELINE TO THIS CENTRAL LOCATION. | CNLA |
| P-78-043 | | P-78-043 | P-0092 | DEVELOP GUIDELINES FOR THE INSTALLATION AND OPERATION OF PIPELINE MONITORING ALARMS ON APPLICABLE SINGLE-FEED SYSTEMS, SUCH AS CHEROKEE, WHICH WILL PROMPTLY ALERT OPERATORS TO EMERGENCY CONDITIONS SUCH AS LINEBREAKS WHICH ARE EVIDENCED BY ABNORMALLY HIGH PRESSURE REDUCTIONS. | CAA |
| P-78-044 | | P-78-044 | P-0092A | AMEND 49 CFR 192.741 TO REQUIRE THAT PIPELINE MONITORING EQUIPMENT BE INSTALLED ON SINGLE-GATE PRESSURE REGULATING DISTRIBUTION SYSTEMS AND THE INFORMATION BE TRANSMITTED TO A CONTINUOUSLY MANNED LOCATION. | CUA |
| p-80-068 | | P-80-068 | P-0154 | THE NTSB RECOMMENDS THAT THE TEXAS PIPELINE COMPANY: EVALUATE EXISTING PROCEDURES FOR LEAK DETECTION AND TAKE STEPS TO MAKE THESE PROCEDURES MORE EFFECTIVE. | CAA |
| p-80-070 | | P-80-070 | P-0154B | THE NTSB RECOMMENDS THAT THE AMERICAN PETROLEUM INSTITUTE: NOTIFY MEMBER COMPANIES OF THE CIRCUMSTANCES OF THIS ACCIDENT AND URGE THEM TO EVALUATE THEIR LEAK DETECTION SYSTEMS AND PROCEDURES AND TO PROVIDE FOR PERIODIC EXAMINATION OF THE AREA AROUND FILLET-WELDED SLEEVES FOR SIGNS OF LEAKAGE. | CNLA |
| p-81-022 | | P-81-022 | P-0169 | THE NTSB RECOMMENDS THAT THE MISSOURI POWER & LIGHT COMPANY: INSTALL ALARMS ON THE EXISTING GAS PRESSURE AND GAS FLOW TELEMETERING EQUIPMENT TO PROMPTLY ALERT OPERATORS TO EMERGENCY CONDITIONS SUCH AS LINEBREAKS WHICH ARE EVIDENCED BY ABNORMALLY HIGH GAS FLOW RATES OR PRESSURE REDUCTIONS. | CAA |
| p-82-036 | | P-82-036 | P-0201 | THE NTSB RECOMMENDS THAT THE MISSOURI POWER AND LIGHT COMPANY: INSTALL EQUIPMENT TO TRANSMIT GAS PRESSURE OR GAS FLOW DATA FROM DISTRICT REGULATOR STATIONS IN CENTRALIA TO THE DISPATCHER AT MOBERLY, MISSOURI, WITH ALARMS TO ALERT THE DISPATCHERS IN THE EVENT OF ABNORMAL GAS FLOW RATES OR PRESSURES. | CAA |

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| p-84-020 | P-84-020 | P-0256 | THE NTSB RECOMMENDS THAT THE MID-AMERICA PIPELINE SYSTEM: PROVIDE TO THE TULSA DISPATCH CONTROL CENTER SUFFICIENT INFORMATION ON OPERATING CONDITIONS ALONG THE PIPELINE SYSTEM TO ENABLE DISPATCHERS TO IDENTIFY THE REASON FOR ANY ACTUATION OF AN OPERATING CONSOLE ALARM. | CUA |
| p-84-025 | P-84-025 | P-0256 | THE NTSB RECOMMENDS THAT THE MID-AMERICA PIPELINE SYSTEM: PROVIDE, BY REMOTELY OPERABLE VALVES OR OTHER MEANS, A CAPABILITY TO RAPIDLY ISOLATE FAILED SECTIONS, AND EVALUATE THE NEED FOR REDUCING THE SEPARATION OF REMOTELY OPERABLE VALVES OR OTHER CLOSURE DEVICES. | CUA |
| p-84-043 | P-84-043 | P-0262 | THE NTSB RECOMMENDS THAT THE BOSTON GAS COMPANY: TEST FOR DEPENDABILITY THE TELEMETER FACILITIES USED TO TRANSMIT PRESSURE INFORMATION AND OTHER CRITICAL INFORMATION FROM DISTRIBUTION SYSTEM OPERATING LOCATIONS TO THE COMMERCIAL POINT STATION, AND REPAIR OR REPLACE THE EQUIPMENT AS NECESSARY. | CAA |
| p-85-026 | P-85-026 | P-0274 | THE NTSB RECOMMENDS THAT THE NATIONAL FUEL GAS COMPANY: INSTALL PRESSURE TRANSMISSION OR ALARM EQUIPMENT AT STRATEGIC PRESSURE-RECORDING POINTS TO ALERT DISPATCHERS PROMPTLY TO EMERGENCY CONDITIONS AS EVIDENCED BY ABNORMAL PRESSURES. | CAA |
| p-87-002 | P-87-002 | P-0286A | THE NTSB RECOMMENDS THAT THE RESEARCH AND SPECIAL PROGRAM ADMINISTRATION, U.S. DEPARTMENT OF TRANSPORATION: AMEND 49 CFR PARTS 192 AND 195 TO REQUIRE THAT OPERATORS OF PIPELINES DEVELOP AND CONDUCT SELECTION, TRAINING, AND TESTING PROGRAMS TO ANNUALLY QUALIFY EMPLOYEES FOR CORRECTLY CARRYING OUT EACH ASSIGNED RESPONSIBILITY WHICH IS NECESSARY FOR COMPLYING WITH 49 CFR PARTS 192 OR 195 AS APPROPRIATE. | CUA |
| p-87-022 | P-87-022 | P-0288B | THE NTSB RECOMMENDS THAT THE OFFICE OF PIPELINE SAFETY: REQUIRE THE INSTALLATION OF REMOTE-OPERATED VALVES ON PIPELINE THAT TRANSPORT HAZARDOUS LIQUIDS, AND BASE THEIR SPACING ON THE POPULATION AT RISK. | CUAS |
| P-90-022 | P-90-022 | P-0297 | THE NTSB RECOMMENDS THAT THE CALNEV PIPE LINE COMPANY: EN HANCE THE COMPUTERIZED OPERATING SYSTEM BY REQUIRING THE DISPATCHER ON DUTY TO ACKNOWLEDGE INDIVIDUALLY EACH ALARM RECEIVED OR BY ADDING A SECOND DISSIMILAR SOUNDING ALARM DENOTING MULTIPLE ALARM CONDITIONS. | CUAN |
| P-91-001 | P-91-001 | P-0299A | THE NTSB RECOMMENDS THAT THE RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION: DEFINE THE OPERATING PARAMETERS THAT MUST BE MONITORED BY PIPELINE OPERATORS TO DETECT ABNORMAL OPERATIONS AND ESTABLISH PERFORMANCE STANDARDS THAT MUST BE MET BY PIPELINE MONITORING SYSTEMS INSTALLED TO DETECT AND LOCATE LEAKS. | OUA |
| P-93-020 | P-93-020 | P-0307D | THE NTSB RECOMMENDS THAT THE AMERICAN PETROLEUM INSTITUTE: IN COOPERATION WITH THE AMERICAN GAS ASSOCIATION, DEVELOP STANDARDS AND GUIDELINES FOR THE DESIGN AND USE OF GRAPHIC INFORMATION DISPLAY SYSTEMS USED BY DISPATCHERS TO CONTROL PIPELINE SYSTEMS. | OAR |
| P-93-022 | P-93-022 | P-0307E | THE NTSB RECOMMENDS THAT THE AMERICAN GAS ASSOCIATION: IN COOPERATION WITH THE AMERICAN PETROLEUM INSTITUTE, DEVELOP STANDARDS AND GUIDELINES FOR THE DESIGN AND USE OF GRAPHIC INFORMATION DISPLAY SYSTEMS USED BY DISPATCHERS TO CONTROL PIPELINE SYSTEMS. | OUR |
| P-95-001 | P-95-001 | P-0309 | THE NTSB RECOMMENDS THAT THE RSPA: EXPEDITE REQUIREMENTS FOR INSTALLING AUTOMATIC- OR REMOTE-OPERATED MAINLINE VALVES ON HIGH-PRESSURE PIPELINES IN URBAN & ENVIRONMENTALLY SENSITIVE AREAS TO PROVIDE FOR RAPID SHUTDOWN OF FAILED PIPELINE SEGMENTS. | CAA |
| P-95-005 | P-95-005 | P-0309A | THE NTSB RECOMMENDS THAT THE TEXAS EASTERN TRANSMISSION CORPORATION: INSTALL AUTOMATIC- OR REMOTE-OPERATED EQUIPMENT ON MAINLINE VALVES IN URBAN AREAS TO PROVIDE FOR RAPID SHUTDOWN OF FAILED PIPELINE SEGMENTS. | CAA |

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| p-95-011 | P-95-011 | P-0309C | THE NTSB RECOMMENDS THAT THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA: ENCOURAGE YOUR MEMBERS TO DEVELOP PROGRAMS, WHICH INCLUDE THE MODIFICATION OF EXISITING VALVES FOR REMOTE OR AUTOMATIC OPERATION, THAT WILL REDUCE TO A MINIMUM THE TIME REQUIRED TO STOP THE FLOW OF NATURAL GAS OR HAZARDOUS LIQUIDS TO FAILED PIPELINE SEGMENTS, ESPECIALLY THOSE SEGMENTS IN URBAN OR ENVIRONMENTALLY SENSITIVE LOCATIONS. | CUA |
| p-95-013 | P-95-013 | P-0309D | THE NTSB RECOMMENDS THAT THE ASSOCIATION OF OIL PIPELINES: ENCOURAGE YOUR MEMBERS TO DEVELOP PROGRAMS, WHICH INCLUDE THE MODIFICATION OF EXISTING VALVES FOR REMOTE OR AUTOMATIC OPERATION, THAT WILL REDUCE TO A MINIMUM THE TIME REQUIRED TO STOP THE FLOW O | CAA |
| p-95-017 | P-95-017 | P-0309F | THE NTSB RECOMMENDS THAT THE AMERICAN GAS ASSOCIATION: ENCOURAGE YOUR MEMBERS TO DEVELOP PROGRAMS, WHICH INCLUDE THE MODIFICATION OF EXISITING VALVES FOR REMOTE OR AUTOMATIC OPERATION, THAT WILL REDUCE TO A MINIMUM THE TIME REQUIRED TO STOP THE FLOW OF NATURAL GAS OR HAZARDOUS LIQUIDS TO FAILED PIPELINE SEGMENTS, ESPECIALLY THOSE SEGMENTS IN URBAN OR ENVIRONMENTALLY SENSITIVE LOCATIONS. | CAA |
| P-98-021 | P-98-021 | P-0318 | THE NTSB RECOMMENDS THAT THE MARATHON ASHLAND PIPE LINE LLC: USE RECURRENT PIPELINE CONTROLLER TRAINING TO (1) EMPHASIZE THE IMPORTANCE OF CAREFULLY & COMPLETELY READING THE TEXT OF & EVALUATING ALL ALARM MESSAGES, & (2) INCREASE CONTROLLER PROFICIENCY IN INTERPRETING & RESPONDING TO CONTROL SYSTEM DATA THAT MAY INDICATE A SYSTEM LEAK. | CAA |
| P-98-022 | P-98-022 | P-0318 | THE NTSB RECOMMENDS THAT THE MARATHON ASHLAND PIPE LINE LLC: EVALUATE THE EFFECTIVENESS OF ALTERNATIVE DISPLAY FORMATS & FREQUENCIES OF ALARMING CRITICAL INFO FOR YOUR SUPERVISORY CONTROL & DATA ACQUISITION SYSTEM & MODIFY THE SYSTEM AS NECESSARY TO ENSURE THAT CONTROLLERS ARE SPECIFICALLY PROMPTED TO CONSIDER THE POSSIBILITY OF LEAKS DURING SYSTEM DEVIATIONS THAT ARE CONSISTENT WITH A LOSS OF PRODUCT FROM A PIPELINE. | CAA |
| P-98-023 | P-98-023 | P-0318 | THE NTSB RECOMMENDS THAT THE MARATHON ASHLAND PIPE LINE LLC: EVALUATE REMOTE & AUTOMATIC VALVE CONTROL TECHNOLOGY TO FACILITATE THE RAPID ISOLATION OF DAMAGED OR LEAKING PIPELINES, & INCORORATE THE APPROPRIATE VALVE CONTROL TECHNOLOGY IN YOUR PIPELINE SY | CAA |
| P-98-027 | P-98-027 | P-0319A | THE NTSB RECOMMENDS THAT THE TENNESSEE GAS PIPELINE COMPANY: REVIEW YOUR SUPERVISORY CONTROL & DATA ACQUISITION SYSTEM & MAKE THE MODIFICATIONS NECESSARY TO INCREASE THE LIKELIHOOD THAT ANY CRITICAL EVENT INVOLVING THE COMPANY'S PIPELINES IS QUICKLY & ACCURATELY REPORTED TO PIPELINE CONTROLLERS, ALLOWING THEM TO TAKE TIMELY ACTION TO CORRECT OR LIMIT THE EFFECTS OF ANY FAILURE IN THE PIPELINE SYSTEM. | CAA |
| P-98-030 | P-98-030 | P-0320 | THE NTSB RECOMMENDS THAT THE PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (ORIGINALLY ISSUED TO RSPA): ASSESS THE POTENTIAL SAFETY RISKS ASSOCIATED WITH ROTATING PIPELINE CONTROLLER SHIFTS AND ESTABLISH INDUSTRY GUIDELINES FOR THE DEVELOPMENT AND IMPLEMENTATION OF PIPELINE CONTROLLER WORK SCHEDULES THAT REDUCE THE LIKELIHOOD OF ACCIDENTS ATTRIBUTABLE TO CONTROLLER FATIGUE. | OAR |
| P-98-032 | P-98-032 | P-0320A | THE NTSB RECOMMENDS THAT THE COLONIAL PIPELINE COMPANY: ASSESS THE POTENTIAL SAFETY RISKS ASSOCIATED WITH YOUR CONTROLLER REST/WORK SCHEDULES & MODIFY, AS NECESSARY, THOSE SCHEDULES TO ENSURE THAT CONTROLLER PERFORMANCE IS NOT COMPROMISED BY FATIGUE. | CAA |

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| P-99-012 | P-99-012 | P-0323 | THE NTSB RECOMMENDS THAT THE PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (ORIGINALLY ISSUED TO RSPA): ESTABLISH WITHIN 2 YEARS SCIENTIFICALLY BASED HOURS-OF-SERVICE REGULATIONS THAT SET LIMITS ON HOURS OF SERVICE, PROVIDE PREDICTABLE WORK AND REST SCHEDULES, AND CONSIDER CIRCADIAN RHYTHMS AND HUMAN SLEEP AND REST REQUIREMENTS. | OAR |
| P-02-005 | P-02-005 | P-0329 | THE NATIONAL TRANSPORTATION SAFETY BOARD THEREFORE MAKES THE FOLLOWING SAFETY RECOMMENDATIONS TO THE RESEARCH AND SPECIAL PROGRAMS ADMINISTRATION: ISSUE AN ADVISORY BULLETIN TO ALL PIPELINE OPERATORS WHO USE SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA) SYSTEMS ADVISING THEM TO IMPLEMENT AN OFF-LINE WORKSTATION THAT CAN BE USED MODIFY THEIR SCADA SYSTEM DATABASE OR TO PERFORM DEVELOPMENTAL AND TESTING WORK INDEPENDENT OF THEIR ON-LINE SYSTEMS. ADVISE OPERATORS TO USE THE OFF-LINE SYSTEM BEFORE ANY MODIFICATIONS ARE IMPLEMENTED TO ENSURE THAT THOSE MODIFICATIONS ARE ERROR-FREE AND THAT THEY CREATE NO ANCILLARY PROBLEMS FOR CONTROLLERS RESPONSIBLE FOR OPERATING THE PIPELINE. | CAA |

# Appendix B

## Additional Liquid Pipeline Accidents Investigated by the Safety Board

### Lively, Texas (August 24, 1996)[1]

A butane pipeline ruptured in a section of pipe weakened by corrosion, and the escaping butane ignited in a residential area, resulting in two fatalities. Before the rupture, automatic safety shutdown of pump stations along the pipeline had created a pressure surge in the pipeline that traveled upstream to the site where the rupture occurred. About 3 minutes and 10 minutes after the pipeline ruptured, the controller received pressure change alarms from the upstream pump station, and after the second alarm, shut down the upstream pump station. Several minutes later, after receiving notification from a resident of a pipeline leak, the operator shut down all pump stations and closed manual valves to isolate the ruptured section of pipe. In the accident, the controller was able to quickly identify the leak using data from the SCADA system, which facilitated the rapid shutdown of the line.

### Sandy Springs, Georgia (March 30, 1998)[2]

A recycling company employee detected an odor of gasoline and later found gasoline flowing up through the ground. He called the owner of a nearby 40-inch pipeline to report a leak. An employee of the pipeline company who eventually received the call called the control center to report the leak and told the control center that he checked out the leak site. Fifteen minutes later, the employee called the control center again to confirm the leak, and a controller shut down the line. No alarms were detected in the control center to indicate that the line had failed; however, the controller was rapidly able to isolate the leak site using the SCADA system.

### Cohasset, Minnesota (July 4, 2002)[3]

A controller using a SCADA system to operate a 34-inch crude oil pipeline noticed a loss of suction and discharge pressure at a pump station. One minute later, the controller received an alarm for decreasing suction pressure at an adjacent pump station. After

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[1] National Transportation Safety Board, *Pipeline Rupture, Liquid Butane Release and Fire Lively, Texas August 24, 1996*, Pipeline Accident Report PAR 98/02 (Washington, DC: NTSB, 1998).

[2] *Pipe Failure and Leak, Morgan Falls Landfill, Sandy Springs, Georgia, March 30, 1998*, Pipeline Accident Report PAR-99/01 (Washington, DC: NTSB, 1999).

[3] National Transportation Safety Board, *Rupture of Enbridge Pipeline and Release of Crude Oil near Cohasset, Minnesota, July 4, 2002*, Pipeline Accident Report PAR-04/01 (Washington, DC: NTSB, 2004).

noticing decreasing discharge pressure at the second pump station, and after conferring with the shift coordinator, the controller and coordinator agreed to shut down the pipeline. Within 3 minutes of the first alarm, the controller began shutting down pumps and closing valves to isolate the suspected leak, and within 9 minutes of the first alarm, remote control valves were closed and the ruptured section of pipeline was isolated. After notifying emergency response and company personnel, controllers began to analyze the SCADA data to locate the leak and estimate the volume released. About 252,000 gallons of crude oil were released, and the cost of the accident was about $5.6 million. The Safety Board concluded that the operator's control center personnel responded in a timely and appropriate manner to indications of the leak. Further, the SCADA system had facilitated the controller's recognition of the leak event.

# Appendix C

## OPS Hazardous Liquid Reporting Form

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $25,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $500,000 as provided in 49 USC 60122

Form Approved
OMB No. 2137-0047

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

**ACCIDENT REPORT – HAZARDOUS LIQUID PIPELINE SYSTEMS**

Report Date ____________
No. ____________
(DOT Use Only)

**INSTRUCTIONS**

**Important:** *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the Office Of Pipeline Safety Web Page at http://ops.dot.gov*

**PART A – GENERAL REPORT INFORMATION** Check: ☐ **Original Report** ☐ **Supplemental Report** ☐ **Final Report**

1. a. Operator's OPS 5-digit Identification Number (if known) /__/__/__/__/__/
   b. If Operator does not own the pipeline, enter Owner's OPS 5-digit Identification Number (if known) /__/__/__/__/__/
   c. Name of Operator ____________
   d. Operator street address ____________
   e. Operator address ____________
   City, County, State and Zip Code

**IMPORTANT: IF THE SPILL IS SMALL, THAT IS, THE AMOUNT IS AT LEAST 5 GALLONS BUT IS LESS THAN 5 BARRELS, COMPLETE THIS PAGE ONLY, UNLESS THE SPILL IS TO WATER AS DESCRIBED IN 49 CFR §195.52(A)(4) OR IS OTHERWISE REPORTABLE UNDER §195.50 AS REVISED IN CY 2001.**

2. Time and date of the accident
   /__/__/__/__/ hr. /__/__/ month /__/__/ day /__/__/ year
3. Location of accident
   *(If offshore, do not complete a through d. See Part C.1)*
   a. Latitude: ________ Longitude: ________
   *(if not available, see instructions for how to provide specific location)*
   b. ____________
   City, and County or Parish
   c. ____________
   State and Zip Code
   d. Mile post/valve station ○ or survey station no. ○
   (whichever gives more accurate location)
   ____________
4. Telephone report
   /__/__/__/__/__/__/ NRC Report Number /__/__/ month /__/__/ day /__/__/ year

5. Losses (Estimated)

**Public/Community Losses reimbursed by operator:**

Public/private property damage $________
Cost of emergency response phase $________
Cost of environmental remediation $________
Other Costs $________
(describe) ____________

**Operator Losses:**

Value of product lost $________
Value of operator property damage $________
Other Costs $________
(describe) ____________
**Total Costs** $________

6. Commodity Spilled ○ Yes ○ No
   (If Yes, complete Parts a through c where applicable)
   a. Name of commodity spilled ____________
   b. Classification of commodity spilled:
      ○ HVLs /other flammable or toxic fluid which is a gas at ambient conditions
      ○ $CO_2$ or other non-flammable, non-toxic fluid which is a gas at ambient conditions
      ○ Gasoline, diesel, fuel oil or other petroleum product which is a liquid at ambient conditions
      ○ Crude oil
   **c. Estimated amount of commodity involved :**
      ○ **Barrels**
      ○ **Gallons (check only if spill is less than one barrel)**
   **Amounts:**
      **Spilled :** ________
      **Recovered:** ________

**CAUSES FOR SMALL SPILLS ONLY (5 gallons to under 5 barrels) :** *(For large spills [5 barrels or greater] see Part H)*

○ **Corrosion** ○ **Natural Forces** ○ **Excavation Damage** ○ **Other Outside Force Damage**
○ **Material and/or Weld Failures** ○ **Equipment** ○ **Incorrect Operation** ○ **Other**

**PART B – PREPARER AND AUTHORIZED SIGNATURE**

____________ (type or print) Preparer's Name and Title ____________ Area Code and Telephone Number

____________ Preparer's E-mail Address ____________ Area Code and Facsimile Number

____________ Authorized Signature ____________ (type or print) Name and Title ________ Date ____________ Area Code and Telephone Number

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**PART C – ORIGIN OF THE ACCIDENT (Check all that apply)**

1. Additional location information
   a. Line segment name or ID ____________________
   b. Accident on Federal land other than Outer Continental Shelf O Yes O No
   c. Is pipeline interstate? O Yes O No

Offshore: O Yes O No *(complete d if offshore)*
d. Area ______________ Block # ___________
State / / or Outer Continental Shelf ☐

2. Location of system involved *(check all that apply)*
   - ☐ Operator's Property
   - ☐ Pipeline Right of Way
   - ☐ High Consequence Area (HCA)? Describe HCA ____________________________

3. Part of system involved in accident
   - O Above Ground Storage Tank
   - O Cavern or other below ground storage facility
   - O Pump/meter station; terminal/tank farm piping and equipment, including sumps
   - O Other Specify: ________________________
   - O Onshore **pipeline**, including valve sites
   - O Offshore **pipeline**, including platforms

*If failure occurred on **Pipeline**, complete items a - g:*

a. Type of leak or rupture
   - O Leak: O Pinhole O Connection Failure *(complete sec. H5)*
     O Puncture, diameter *(inches)* ______________
   - O Rupture: O Circumferential – Separation
     O Longitudinal – Tear/Crack, length *(inches)* _________
     Propagation Length, total, both sides *(feet)* _______
   - O N/A
   - O Other ____________________

b. Type of block valve used for isolation of immediate section:
   Upstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve
   Downstream: ☐ Manual ☐ Automatic ☐ Remote Control ☐ Check Valve

c. Length of segment isolated ______ ft
d. Distance between valves ______ ft
e. Is segment configured for internal inspection tools? O Yes O No
f. Had there been an in-line inspection device run at the point of failure? O Yes O No O Don't Know
   O Not Possible due to physical constraints in the system
g. If Yes, type of device run *(check all that apply)*

| | |
|---|---|
| ☐ High Resolution Magnetic Flux tool | Year run: _______ |
| ☐ Low Resolution Magnetic Flux tool | Year run: _______ |
| ☐ UT tool | Year run: _______ |
| ☐ Geometry tool | Year run: _______ |
| ☐ Caliper tool | Year run: _______ |
| ☐ Crack tool | Year run: _______ |
| ☐ Hard Spot tool | Year run: _______ |
| ☐ Other tool | Year run: _______ |

4. Failure occurred on
   O Body of Pipe O Pipe Seam O Scraper Trap
   O Pump O Sump O Joint
   O Component O Valve O Metering Facility
   O Repair Sleeve O Welded Fitting O Bolted Fitting
   O Girth Weld
   Other *(specify)* __________________

Year the component that failed was installed: / / / / /

5. Maximum operating pressure *(MOP)*
   a. Estimated pressure at point and time of accident: ________ *PSIG*
   b. MOP at time of accident: ________ *PSIG*
   c. Did an overpressurization occur relating to the accident? O Yes O No

**PART D – MATERIAL SPECIFICATION**

1. Nominal pipe size *(NPS)* / / / / / in.
2. Wall thickness / / / / / in.
3. Specification ____________ SMYS / / / / / / /
4. Seam type ______________________________
5. Valve type ______________________________
6. Manufactured by ____________ in year / / / / /

**PART E – ENVIRONMENT**

1. Area of accident
   O Under pavement O In open ditch
   O Underground O Above ground
   O Inside/under building O Under water
   O Other ________________
2. Depth of cover: ______________ inches

**PART F – CONSEQUENCES**

1. **Consequences** *(check and complete all that apply)*

| a. | Fatalities | Injuries |
|---|---|---|
| Number of operator employees: | _____ | _____ |
| Contractor employees working for operator: | _____ | _____ |
| General public: | _____ | _____ |
| **Totals:** | _____ | _____ |

b. Was pipeline/segment shutdown due to leak? O Yes O No
   If Yes, how long? _____ days _____ hours _____ minutes

c. Product ignited O Yes O No d. Explosion O Yes O No
e. ☐ Evacuation *(general public only)* / / / / / people
   Reason for Evacuation:
   O Precautionary by company
   O Evacuation required or initiated by public official
f. Elapsed time until area was made safe:
   / / / hr. / / / min.

2. **Environmental Impact**
   a. Wildlife Impact: Fish/aquatic O Yes O No
      Birds O Yes O No
      Terrestrial O Yes O No
   b. Soil Contamination O Yes O No
      If Yes, estimated number of cubic yards: __________
   c. Long term impact assessment performed: O Yes O No
   d. Anticipated remediation O Yes O No
      If Yes, check all that apply: ☐ Surface water ☐ Groundwater ☐ Soil ☐ Vegetation ☐ Wildlife

   e. Water Contamination: O Yes O No *(If Yes, provide the following)*
      Amount in water ________ barrels
      Ocean/Seawater O No O Yes
      Surface O No O Yes
      Groundwater O No O Yes
      Drinking water O No O Yes *(If Yes, check below.)*
      O Private well O Public water intake

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**PART G – LEAK DETECTION INFORMATION**

1. Computer based leak detection capability in place? O Yes O No
2. Was the release initially detected by? (check one): O CPM/SCADA-based system with leak detection O Static shut-in test or other pressure or leak test O Local operating personnel, procedures or equipment O Remote operating personnel, including controllers O Air patrol or ground surveillance O A third party O Other (specify) ________
3. Estimated leak duration days ____ hours ____

**PART H – APPARENT CAUSE**

*Important: There are 25 numbered causes in this Part H. Check the box corresponding to the primary cause of the accident. Check one circle in each of the supplemental categories corresponding to the cause you indicate. See the instructions for guidance.*

**H1 – CORROSION**

1. ☐ External Corrosion
2. ☐ Internal Corrosion

(Complete items a – e where applicable.)

a. Pipe Coating: O Bare O Coated

b. Visual Examination: O Localized Pitting O General Corrosion O Other ________

c. Cause of Corrosion: O Galvanic O Atmospheric O Stray Current O Microbiological O Cathodic Protection Disrupted O Stress Corrosion Cracking O Selective Seam Corrosion O Other ________

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering accident?
O No O Yes, Year Protection Started: /__/__/__/__/

e. Was pipe previously damaged in the area of corrosion?
O No O Yes ⇒ Estimated time prior to accident: /__/__/ *years* /__/__/ *months* *Unknown* ☐

**H2 – NATURAL FORCES**

3. ☐ Earth Movement ⇒ O Earthquake O Subsidence O Landslide O Other ________
4. ☐ Lightning
5. ☐ Heavy Rains/Floods ⇒ O Washouts O Flotation O Mudslide O Scouring O Other ________
6. ☐ Temperature ⇒ O Thermal stress O Frost heave O Frozen components O Other ________
7. ☐ High Winds

**H3 — EXCAVATION DAMAGE**

8. ☐ Operator Excavation Damage (including their contractors/Not Third Party)
9. ☐ Third Party (*complete a-f*)

a. Excavator group
O General Public O Government O Excavator other than Operator/subcontractor

b. Type: O Road Work O Pipeline O Water O Electric O Sewer O Phone/Cable O Landowner-not farming related O Farming O Railroad O Other liquid or gas transmission pipeline operator or their contractor O Nautical Operations O Other ________

c. Excavation was: O Open Trench O Sub-strata (boring, directional drilling, etc…)

d. Excavation was an ongoing activity (Month or longer) O Yes O No If Yes, Date of last contact /__/__/__/

e. Did operator get prior notification of excavation activity?
O Yes; Date received: /__/__/ mo. /__/__/ day /__/__/__/__/ yr. O No
Notification received from: O One Call System O Excavator O Contractor O Landowner

f. Was pipeline marked as result of location request for excavation? O No O Yes (*If Yes, check applicable items i - iv*)
i. Temporary markings: O Flags O Stakes O Paint
ii. Permanent markings: O
iii. Marks were (check one) : O Accurate O Not Accurate
iv. Were marks made within required time? O Yes O No

**H4 – OTHER OUTSIDE FORCE DAMAGE**

10. ☐ Fire/Explosion as primary cause of failure ⇒ Fire/Explosion cause: O Man made O Natural
11. ☐ Car, truck or other vehicle not relating to excavation activity damaging pipe
12. ☐ Rupture of Previously Damaged Pipe
13. ☐ Vandalism

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**H5 – MATERIAL AND/OR WELD FAILURES**

**Material**

14. ☐ Body of Pipe ⇒ O Dent O Gouge O Bend O Arc Burn O Other ____________
15. ☐ Component ⇒ O Valve O Fitting O Vessel O Extruded Outlet O Other ____________
16. ☐ Joint ⇒ O Gasket O O-Ring O Threads O Other ____________

**Weld**

17. ☐ Butt ⇒ O Pipe O Fabrication O Other ____________
18. ☐ Fillet ⇒ O Branch O Hot Tap O Fitting O Repair Sleeve O Other ____________
19. ☐ Pipe Seam ⇒ O LF ERW O DSAW O Seamless O Flash Weld
O HF ERW O SAW O Spiral O Other ____________

*Complete a-g if you indicate* ***any*** *cause in part H5.*

a. Type of failure:
O Construction Defect ⇒ O Poor Workmanship O Procedure not followed O Poor Construction Procedures
O Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? O Yes O No

c. Was part which leaked pressure tested before accident occurred? O Yes, *complete d-g* O No

d. Date of test: /__/__/__/__/ yr. /__/__/ mo. /__/__/ day

e. Test medium: O Water O Inert Gas O Other ____________________

f. Time held at test pressure: /__/__/ hr.

g. Estimated test pressure at point of accident: ____________________ *PSIG*

**H6 – EQUIPMENT**

20. ☐ Malfunction of Control/Relief Equipment ⇒ O Control valve O Instrumentation O SCADA O Communications
O Block valve O Relief valve O Power failure O Other ____________
21. ☐ Threads Stripped, Broken Pipe Coupling ⇒ O Nipples O Valve Threads O Dresser Couplings O Other ____________
22. ☐ Seal Failure ⇒ O Gasket O O-Ring O Seal/Pump Packing O Other ____________

**H7 – INCORRECT OPERATION**

23. ☐ Incorrect Operation

a. Type: O Inadequate Procedures O Inadequate Safety Practices O Failure to Follow Procedures
O Other ______________________________

b. Number of employees involved who failed a post-accident test: drug test: /__/__/__/ alcohol test /__/__/__/

**H8 – OTHER**

24. ☐ Miscellaneous, *describe:* ________________________________________________
25. ☐ Unknown
O Investigation Complete O Still Under Investigation *(submit a supplemental report when investigation is complete)*

**PART I – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT** *(Attach additional sheets as necessary)*



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# Appendix D

## NTSB SCADA Survey

**NATIONAL TRANSPORTATION SAFETY BOARD**
**Washington D.C. 20594**

# SCADA QUESTIONNAIRE

The mission of the National Transportation Safety Board is to prevent accidents and save lives in transportation. We are tasked with investigating transportation accidents, determining their probable causes, and making recommendations to prevent such accidents from happening again. One of the tools the Board uses to complete its mission is safety studies. Currently, the Safety Board is conducting a study of Supervisory Control And Data Acquisition (SCADA) systems. In this study, the Board is focusing on the factors that can influence the detection of a pipeline leak. It is with this purpose in mind that we are asking you to complete this questionnaire. Information about your SCADA system will help in our effort. The form should require approximately 40 minutes of your time and is voluntary. This form is required to display a currently valid Office of Management and Budget (OMB) control number. Information provided to the Safety Board using this questionnaire will be used for statistical purposes only. Individual questionnaires will be kept confidential, as provided by the Confidential Information and Statistical Efficiency Act of 2002. If you should have any questions about any aspects of this questionnaire or its use, please feel free to contact Robert Molloy (Safety Studies Division, NTSB) at 202-314-6516 or via email at molloyr@ntsb.gov. Thank you for your assistance.

## Pipeline Information

1. How many miles of pipeline (liquid) are in your company's system?
☐ Less than 50 ☐ 50-99 ☐ 100-499 ☐ 500-999 ☐ 1000-1999 ☐ 2000-2999
☐ 3000-3999 ☐ 4000-4999 ☐ 5000 or more

2. What types of commodities do your pipelines carry? (Check all that apply)
☐ Crude oil ☐ Gasoline ☐ Kerosene ☐ Heating oil ☐ Diesel fuel ☐ Natural Gas Liquids ☐ Chemicals
☐ Highly volatile liquids ☐ Other
______________________________________________________________

3. How many trunk lines are operated by your control center?
☐ Less than 4 ☐ 4-6 ☐ 7-9 ☐ 10-15 ☐ 16-20 ☐ more than 20

4. How many miles of trunk lines are in your system?
☐ Less than 50 ☐ 50-99 ☐ 100-499 ☐ 500-999 ☐ 1000-1999 ☐ 2000-2999
☐ 3000-3999 ☐ 4000-4999 ☐ 5000 or more

5. How many pump stations are in your pipeline system?
☐ Less than 50 ☐ 50-99 ☐ 100-199 ☐ 200-299 ☐ 300-399 ☐ 400 or more

6. Approximately how much commodity do your trunk pipelines transport in a day (barrels/day)?
☐ Less than 10,000 ☐ 10,000-49,999 ☐ 50,000-99,999 ☐ 100,000-499,999
☐ 500,000-999,000 ☐ 1,000,000 or more

7. How many separate primary control centers does your company operate?
☐ 1 (Only this one) ☐ 2 ☐ 3 ☐ 4 ☐ more than 4

**Complete the next section for each control center-each center should have received a copy of this questionnaire**

## SCADA Information

8. Does your company currently use computers to remotely monitor and operate a pipeline system. (e.g. SCADA system)?
☐ Yes ☐ No (If no, indicate whether you plan to install a SCADA system in the future and, if so, include an expected installation date.)
______________________________________________________________
______________________________________________________________
______________________________________________________________
______________________________________________________________

**If your company does not have a SCADA system, you are finished with the questionnaire. Thank you.**

OMB Number-3147-0022

9. When did your company first install a computer-based SCADA system?
☐ Before 1970 ☐ 1970-1979 ☐ 1980-1989 ☐ 1990-1999 ☐ 2000 or later

10. What percentage of all of your pipelines is controlled by SCADA systems?
☐ 0-19% ☐ 20-39% ☐ 40-59% ☐ 60-79% ☐ 80-99% ☐ 100%

11. How was your first computer-based SCADA system obtained?
☐ Developed by the company ☐ Company purchased software and integrated it into system ☐ Inherited
☐ Developed by a SCADA integrator ☐ Other (describe)________________________________________________

_______________________________________________________________________________________________

_______________________________________________________________________________________________

12. How many different SCADA systems are in operation in this control center?
☐ 1 ☐ 2 ☐ 3 ☐ 4 or more

**If your control center has multiple SCADA systems please complete questions 13 through 22 for each system. (Extra sheets for those questions are attached to this questionnaire)**

13. When was the initial version of the currently operating base SCADA system installed? (Check all that apply.)
☐ Before 1995 ☐ 1996-1997 ☐ 1998-1999 ☐ 2000-2001 ☐ 2002 or later

14. How was the current SCADA system obtained?
☐ Developed by the company ☐ Company purchased software and integrated it into system
☐ Developed by a SCADA integrator ☐ Other (describe)__________________________________________________

_______________________________________________________________________________________________

_______________________________________________________________________________________________

15. Name of vendor who supplied current SCADA software? (Vendor name at time of purchase)
______________________________________________ ☐ Not applicable

16. Current SCADA software product name and version?
______________________________________________ ☐ Not applicable

17. In the Table below please indicate major changes to the SCADA system since its inception. Reasons for changes might include adding leak detection, replacing controller interface, merger/acquisition, platform upgrade, changing operating system, or any other major reason.

| Replacement/Upgrade | Reason |
|---|---|
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |
| | |

18. Is your company planning to upgrade/replace your SCADA system?
☐ Yes, upgrade ☐ Yes, replace ☐ No **(If no, skip to item 20.)**

19. Why is your company considering an upgrade/replacement? (Check all that apply)
☐ Adding/improving security ☐ Improving controller interface ☐ Merger/acquisition ☐ New pipeline
☐ Hardware/software obsolescence ☐Relocation ☐System performance ☐ Other (describe)_________________

_______________________________________________________________________________________________

20. Is your company currently upgrading/replacing your SCADA system?
☐ Yes, upgrade ☐ Yes, replace ☐ No **(If no skip to item 22.)**

21. Why is your company upgrading/replacing your SCADA system? (Check all that apply)
☐ Adding/improving security ☐ Improving controller interface ☐ Merger/acquisition ☐ New pipeline
☐ Hardware/software obsolescence ☐Relocation ☐System performance ☐Other (describe)__________________
________________________________________________________________________________

22. Which of the following functions does your current SCADA system perform? (Check all that apply)
☐ Basic volume balance ☐ Batch accounting ☐ Batch tracking ☐ Chemical addition control
☐ Trends ☐ Equipment performance modeling ☐ Leak detection/ Computational Pipeline Monitoring systems (CPM)
☐ Meter proving ☐ Operating data acquisition ☐ Pipeline fault isolation ☐ Pipeline modeling
☐ Product level tracking ☐ Remote valve operations
☐ Clear paths monitoring (assuring valves in the intended path are open) ☐ Other (describe)_____________________
________________________________________________________________________________

23. Which of the following methods does your company use for leak detection? (Check all that apply)
☐ Aerial or ground line patrol ☐ Third-party reports ☐ Landowner awareness program ☐ Hydrocarbon sensors
☐ CPM embedded in SCADA system ☐ External/third party independent (CPM) system
☐ Monitoring of pipeline conditions with a SCADA system ☐ Vapor sensors at stations
☐ Other (describe)________________________________________________________________

24. What methods of software-based computational pipeline monitoring (CPM) does your company operate? (Methods from API 1130) (Check all that apply)
☐ Line balance ☐ Volume balance ☐ Compensated mass balance ☐ Real-time transient modeling
☐ Statistical analysis ☐ Pressure/flow monitoring ☐ Acoustic/negative pressure wave ☐ None
☐ Other ___________________________________________________________________________

25. Proportion of lines covered with a CPM system?
☐ 0-19% ☐ 20-39% ☐ 40-59% ☐ 60-79% ☐ 80-99% ☐ 100%

26. How many CPM systems are on your primary SCADA system?
☐ 1 ☐ 2 ☐ 3 ☐ 4 or more
**If more than one CPM system, answer questions 27- 31 for the CPM system that monitors the most miles of pipe.**

27. When was your current CPM system installed?
☐ Before 1995 ☐ 1996-1997 ☐ 1998-1999 ☐ 2000-2001 ☐ 2002 or later ☐ Not applicable

28. How was the CPM system obtained?
☐ Embedded in SCADA system ☐ Developed by company ☐ Not applicable
☐ Developed by a third party provider ☐ Other (describe)________________________________________
________________________________________________________________________________
________________________________________________________________________________

29. Name of vendor who supplied CPM software?
________________________________________ ☐ Not applicable

30. CPM software product name and version?
________________________________________ ☐ Not applicable

31. How is your CPM system(s) integrated with your SCADA system? (Check all that apply)
☐ Embedded in SCADA system ☐ Collects data from SCADA system ☐ Separate displays
☐ Transmits alarms to SCADA system ☐ Other (describe)________________________________________

32. How were your last 5 system leaks (5 gallons or more) first detected? (Place the number of detections by each method in the blank.)

___Controller ___ Third party leak detection system ___Third party ___Field personnel ___Excavator
___Other (describe)________________________________________________________________

33. Has your CPM system ever been the first indication of a leak?
☐ Yes ☐ No ☐ Not applicable

34. Did the CPM system designer identify an expected performance in the leak detection thresholds?
☐ Yes ☐ No ☐ Not applicable

35. What factors have prompted a change in leak detection thresholds? (Check all that apply)
☐ Nuisance alarms ☐ Field instrumentation ☐ Improve detection sensitivity ☐ Other (describe)_____________
_____________________________________________________________________________________________

36. Is the leak detection threshold dynamically tuned (i.e., changing for steady state operation relative to startup operations)?
☐ Yes ☐ No ☐ Not applicable

37. How are pipeline leaks isolated? (Check all that apply)
☐ Check valves ☐ SCADA-operated valves ☐ Manual valves ☐ Other (describe)___________________________

38. How many telemetered data points does your system communicate with?
☐ Less than 50 ☐ 50-99 ☐ 100-499 ☐ 500-999 ☐ 1000-4999 ☐ 5000 or more

39. Approximately how many dumb (non-programmable) remote terminal units are on your pipeline system?
☐ Less than 10 ☐ 10-49 ☐ 50-99 ☐ 100-999 ☐ 1000 or more

40. Approximately how many programmable logic controls (PLC) and flow computers are on your system?
☐ Less than 10 ☐ 10-49 ☐ 50-99 ☐ 100-999 ☐ 1000 or more

41. What happens if the primary SCADA system shuts down unexpectedly? (Check all that apply)
☐ Pipeline shuts down after _______ hours/minutes ☐ Normal pipeline operations continue indefinitely
☐ Backup system becomes operational ☐ Dispatch people to monitor ☐ Pipeline shuts down immediately
☐ Other (describe)__________________________________________________________________________

42. What methods of communication does your system use for data communications between the pipeline (pumping stations, field services) and the control center? (Check all that apply. Circle primary method.)
☐ 1-way radio ☐ 2-way radio ☐ Cellular ☐ Leased lines ☐ Microwave ☐ Satellite ☐ Fiber
☐ Other (describe)__________________________________________________________________________

43. What backup method of data communication does your system use between the pipeline (pumping stations, field services) and the control center? (Check all that apply. Circle primary method.)
☐ 1-way radio ☐ 2-way radio ☐ Cellular ☐ Leased lines ☐ Microwave ☐ Satellite ☐ Fiber ☐ None
☐ Dial-up ☐ Other (describe)______________________________________________________________________

44. What happens when a primary data communication outage occurs (e.g., an entire satellite hub fails, telephone line into building severed)? Check all that apply.
☐ Manual switch to backup communication system ☐ Automated switch to backup communication system
☐ Nothing ☐ Pipeline shuts down immediately ☐ Pipeline shuts down after _______ hours/minutes
☐ Dispatch people to monitor ☐ Other (describe) ____________________________________________________

45. Approximately how often does a major unscheduled communication outage occur?
☐ Daily ☐ Weekly ☐ Monthly ☐ Quarterly ☐ Other (describe)_______________________________________

46. Have your primary and backup communication systems ever failed at the same time?
☐ Yes ☐ No ☐ NA (No backup communications system.)

47. How is a major communication failure indicated to a controller? (Check all that apply)
☐ Audible alarm ☐ Visual alarm ☐ Data no longer changing
☐ Data characteristics change (e.g., reverse video, flashing) ☐ Other (describe)___________________________

48. How is a communication failure with a field device indicated to a controller? (Check all that apply)
☐ Audible alarm ☐ Visual alarm ☐ Data no longer being updated
☐ Data characteristics change (e.g., reverse video, flashing) ☐ Other (describe) ___________________________

49. Approximately how often does a communication outage to a field device occur?
☐ Daily ☐ Weekly ☐ Monthly ☐ Quarterly ☐ Other (describe) _____________________________________

50. What method of communication does your system use between the control center and corporate systems? (Check all that apply. Circle primary method.)
☐ Wide area network (WAN) ☐ Local area network (LAN) ☐ Internet
☐ Other (describe)______________________________________________

51. Approximately what proportion of controller training time is devoted to the following

| **Initial** | | **Refresher** | |
|---|---|---|---|
| Demonstration (OJT) | _______% | Demonstration (OJT) | _______% |
| Classroom | _______% | Classroom | _______% |
| Films | _______% | Films | _______% |
| Computer-based training | _______% | Computer-based training | _______% |
| Simulator | _______% | Simulator | _______% |
| Manuals | _______% | Manuals | _______% |
| Bulletins | _______% | Bulletins | _______% |
| Handbooks | _______% | Handbooks | _______% |
| Workbooks | _______% | Workbooks | _______% |
| Other _____________ | _______% | Other _____________ | _______% |

52. Does your company use a simulator to train controllers?
☐ Yes ☐ No **(If no, skip to question 56)**

53. Name of vendor who supplied the simulator?
_____________________________________________ ☐ Developed in-house

54. What is the simulator product name and version?
_____________________________________________

55. Is your simulator generic or specific to your pipeline?
☐ Generic ☐ Specific ☐ Both

56. Does your company present SCADA alarms in a prioritized fashion?
☐ Yes ☐ No

57. How many priorities of alarms does your company have?
☐ One ☐ Two ☐ Three ☐ Four or more (Describe the priorities below.)
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________

58. How does your SCADA system differentiate different priorities of alarms for controllers (e.g., colors used, flashing, audible, grouping)?
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________

59. How are leak detection alarms indicated on your display (e.g., location, characteristics of alarm, listed with SCADA alarms)?
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________

60. Does your company review SCADA alarm history (i.e., to refine scope or minimize redundant alarms for controller benefit)?
☐ Yes ☐ No (If yes, describe the frequency of these reviews, who performs the reviews, and the review process below.)

61. What processes does your company use to review your SCADA system (i.e., comparing physical pipeline hardware to SCADA representation [point audits], integrity testing [continuity check between SCADA and field point], controller brainstorming)?
Describe the frequency of these reviews, who performs the reviews, and the review process below.

62. Has your SCADA system been reviewed by the Office of Pipeline Safety?
☐ No ☐ Yes, part of a standard inspection ☐ Yes, part of a records review ☐ Yes, part of an accident investigation
☐ Yes, other reason

63. Has your SCADA system controller/human-machine interface been evaluated by an outside consultant?
☐ Yes ☐ No

64. Pipeline SCADA systems have allowed more efficient pipeline operations.
☐ Strongly agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly disagree

65. Pipeline SCADA systems have allowed safer pipeline operations.
☐ Strongly agree ☐ Agree ☐ Neutral ☐ Disagree ☐ Strongly disagree

66. What recommendations do you have to improve SCADA and/or CPM systems?

67. Additional comments regarding safety and SCADA/CPM systems.

**Thank you for your assistance.**

# Appendix E

## SCADA Survey Results

### SCADA Survey Overview Results

**Descriptive Summary of Data by Question Number**

1. How many miles of pipeline (liquid) are in your company's system?

| | |
|---|---|
| 11 | Less than 50 |
| 8 | 50-99 |
| 22 | 100-499 |
| 12 | 500-999 |
| 11 | 1000-1999 |
| 4 | 2000-2999 |
| 5 | 3000-3999 |
| 0 | 4000-4999 |
| 14 | 5000 or more |
| 11 | Missing[1] |
| **98** | **Total** |

2. What types of commodities do your pipelines carry?[2]

| | |
|---|---|
| 47.7% | Crude oil |
| 47.7% | Diesel fuel |
| 47.1% | Gasoline |
| 34.1% | Highly volatile liquids |
| 34.1% | Natural Gas Liquids |
| 31.8% | Kerosene |
| 20.5% | Heating oil |
| 18.4% | Other |
| 17.0% | Chemicals |

3. How many trunk lines are operated by your control center?

| | |
|---|---|
| 51 | Less than 4 |
| 5 | 4-6 |

[1] The missing category represents surveys in which there was no data entered for the question. In many cases the missing data is from a survey that reported on a second or third SCADA system at a control center.

[2] For questions in which more than one response was allowed the results are reported as the percentage of companies that selected each item in the survey.

| | |
|---|---|
| 5 | 7-9 |
| 10 | 10-15 |
| 4 | 16-20 |
| 13 | more than 20 |
| 10 | Missing |
| **98** | **Total** |

4. How many miles of trunk lines are in your system?

| | |
|---|---|
| 27 | Less than 50 |
| 7 | 50-99 |
| 16 | 100-499 |
| 9 | 500-999 |
| 10 | 1000-1999 |
| 4 | 2000-2999 |
| 4 | 3000-3999 |
| 0 | 4000-4999 |
| 11 | 5000 or more |
| 10 | Missing |
| **98** | **Total** |

5. How many pump stations are in your pipeline system?

| | |
|---|---|
| 66 | Less than 50 |
| 9 | 50-99 |
| 4 | 100-199 |
| 8 | 200-299 |
| 1 | 300-399 |
| 0 | 400 or more |
| 10 | Missing |
| **98** | **Total** |

6. Approximately how much commodity do your trunk pipelines transport in a day (barrels/day)?

| | |
|---|---|
| 13 | Less than 10,000 |
| 23 | 10,000-49,999 |
| 13 | 50,000-99,999 |
| 11 | 100,000-499,999 |
| 8 | 500,000-999,000 |
| 16 | 1,000,000 or more |
| 14 | Missing |
| **98** | **Total** |

7. How many separate primary control centers does your company operate?

| | |
|---|---|
| 61 | 1 (Only this one) |
| 15 | 2 |
| 5 | 3 |
| 3 | 4 |
| 3 | more than 4 |
| 11 | Missing |
| **98** | **Total** |

8. Does your company currently use computers to remotely monitor and operate a pipeline system. (e.g. SCADA system)?

| | |
|---|---|
| 84 | Yes |
| 6 | No |
| 8 | Missing |
| **98** | **Total** |

9. When did your company first install a computer-based SCADA system?

| | |
|---|---|
| 9 | Before 1970 |
| 24 | 1970-1979 |
| 24 | 1980-1989 |
| 19 | 1990-1999 |
| 4 | 2000 or later |
| 18 | Missing |
| **98** | **Total** |

10. What percentage of all of your pipelines is controlled by SCADA systems?

| | |
|---|---|
| 2 | 0-19% |
| 1 | 20-39% |
| 1 | 40-59% |
| 10 | 60-79% |
| 28 | 80-99% |
| 40 | 100% |
| 16 | Missing |
| **98** | **Total** |

11. How was your first computer-based SCADA system obtained?

| | |
|---|---|
| 19 | Developed by the company |
| 16 | Company purchased software and integrated it into system |
| 8 | Inherited |
| 35 | Developed by a SCADA integrator |

| | |
|---|---|
| 2 | Other |
| 18 | Missing |
| **98** | **Total** |

12. How many different SCADA systems are in operation in this control center?

| | |
|---|---|
| 70 | 1 |
| 8 | 2 |
| 4 | 3 |
| 1 | 4 or more |
| 15 | Missing |
| **98** | **Total** |

13. When was the initial version of the currently operating base SCADA system installed? (Check all that apply.)

| | |
|---|---|
| 37 | Before 1995 |
| 17 | 1996-1997 |
| 12 | 1998-1999 |
| 8 | 2000-2001 |
| 7 | 2002 or later |
| 17 | Missing |
| **98** | **Total** |

14. How was the current SCADA system obtained?

| | |
|---|---|
| 9 | Developed by the company |
| 29 | Company purchased software and integrated it into system |
| 41 | Developed by a SCADA integrator |
| 4 | Other |
| 15 | Missing |
| **98** | **Total** |

15. Name of vendor who supplied current SCADA software? (Vendor name at time of purchase)

| | |
|---|---|
| 1 | Allen Bradley |
| 1 | American Automation |
| 2 | Aspen Tech |
| 1 | Automation Electronics |
| 1 | Baker |
| 1 | Insight Automation |
| 1 | Bristol Babcock |
| 1 | Collins Communication |
| 2 | Control Applications/Forney Engineering |

| | |
|---|---|
| 1 | CSI |
| 1 | Curry controls |
| 1 | DATAP |
| 1 | Dtar Technologies LTD |
| 1 | Fisher |
| 1 | Foxboro |
| 1 | Ge Fanuc Cimplicity Software |
| 1 | Gse, Valmet |
| 1 | Hinz Automation |
| 3 | Honeywell |
| 1 | Hydril |
| 1 | Linco Electromatic Inc. |
| 1 | McClerkin and Associates |
| 3 | Metso Automation |
| 1 | Neles Automation |
| 1 | Petroeon Systems |
| 1 | Praxis Instruments Inc |
| 1 | Process Controls/Lic Energy |
| 1 | Realflex |
| 1 | Rockwell |
| 2 | SAIC |
| 1 | Sandwell-DATAP |
| 3 | Standard Automation |
| 2 | Scallon Controls |
| 1 | Square D |
| 5 | Teledyne |
| 8 | Telvent |
| 1 | Trans Continental |
| 13 | Valmet Automation |
| 1 | Verano Supplies RTAP |
| 1 | Wheatland Systems |
| 8 | Wonderware |
| 1 | Not applicable |
| 16 | Missing |
| **98** | **Total** |

16. Current SCADA software product name and version?

| | |
|---|---|
| 1 | Accol 5.12 |
| 1 | Cimplicity Plant Edition V6 |
| 1 | DATAP |
| 1 | Evolution Scada Veri 4.1 |
| 1 | FactoryLink 7.0 |
| 1 | FactorySuite 2000 |
| 1 | Fisher ROC |

| | |
|---|---|
| 1 | FoxSCADA Rev 5.6.1.4 |
| 1 | Honeywell |
| 1 | Honeywell Tdc-3000 |
| 1 | Hydril |
| 6 | Intellution Fix Ver. 6.15, 6.1(2) |
| 2 | Intouch 7.11 |
| 1 | Iris 76000 |
| 1 | Lookout |
| 1 | Mini-Mast |
| 1 | Modicon Plc/Plds |
| 1 | MOSCAD Version 6.0 |
| 2 | Not Applicable |
| 19 | Oasys 5.0, 5.2(8), 5.2.2(4), 6.0, 6.2(2) |
| 5 | Open Vector- 3.62, 4.11 (2), 4.1.1, 4.2 |
| 1 | PlantScape |
| 2 | PROCYS |
| 1 | Process Window 2.35 |
| 3 | RealFlex 1.22, 4.2e1 |
| 1 | Rockwell RSView 32 |
| 1 | RS Logix V |
| 2 | S/3 SCADA 4.11 [5.1] |
| 1 | Series VII |
| 2 | SetCom |
| 2 | Telvent 5.2, 6.0.6.3 |
| 1 | TSS SCADA |
| 1 | UCOS Version 3436.3 |
| 1 | US Data FactoryLink Ver3.02a |
| 1 | Vector 3.6-2 |
| 11 | Wonderware (Intouch) 5.1b, 7.0, 7.1, 7.11, 7.2, 8.0(2), 2000 |
| 1 | X-MidSHIPS Version 4.1 |
| 17 | Missing |
| **98** | **Total** |

17. In the Table below please indicate major changes to the SCADA system since its inception. Reasons for changes might include adding leak detection, replacing controller interface, merger/acquisition, platform upgrade, changing operating system, or any other major reason. **"Text"**

| | |
|---|---|
| 22 | Upgrade Hardware/Software- Obsolescence |
| 27 | Upgrade Software- Current Version |
| 13 | Y2K |
| 12 | Merger |
| 15 | Communications |
| 35 | Platform Upgrade |
| 17 | Pipeline Additions |

19 Leak Detection
3 Consolidate Control Centers
14 Performance
4 Human Machine Interface
2 Security
4 Backup Control Center

18. Is your company planning to upgrade/replace your SCADA system?

27 Yes, upgrade
19 Yes, replace
34 No
18 Missing
**98 Total**

19. Why is your company considering an upgrade/replacement?

53.3% Adding/improving security
45.6% Improving controller interface
15.6% Merger/acquisition
4.4% New pipeline
82.2% Hardware/software obsolescence
8.9% Relocation
55.6% System performance
24.4% Other

20. Is your company currently upgrading/replacing your SCADA system?

16 Yes, upgrade
12 Yes, replace
49 No
21 Missing
**98 Total**

21. Why is your company upgrading/replacing your SCADA system? (Check all that apply)

31.0% Adding/improving security
31.0% Improving controller interface
27.6% Merger/acquisition
3.4% New pipeline
75.9% Hardware/software obsolescence
10.3% Relocation
48.3% System performance
13.8% Other

22. Which of the following functions does your current SCADA system perform? (Check all that apply)

65.9% Basic volume balance
29.3% Batch accounting
50% Batch tracking
24.4% Chemical addition control
85.4% Trends
12.2% Equipment performance modeling
58.5% Leak detection/ Computational Pipeline Monitoring systems (CPM)
32.9% Meter proving
87.8% Operating data acquisition
20.7% Pipeline fault isolation
11.0% Pipeline modeling
61.0% Product level tracking
92.7% Remote valve operations
40.2% Clear paths monitoring (assuring valves in the intended path are open)
4.9% Other

23. Which of the following methods does your company use for leak detection? (Check all that apply)

95.3% Aerial or ground line patrol
76.7% Third-party reports
84.9% Landowner awareness program
31.4% Hydrocarbon sensors
37.2% CPM embedded in SCADA system
24.4% External/third party independent (CPM) system
90.7% Monitoring of pipeline conditions with a SCADA system
39.5% Vapor sensors at stations
11.6% Other

24. What methods of software-based computational pipeline monitoring (CPM) does your company operate? (Methods from API 1130)

45.2% Line balance
43.5% Volume balance
36.5% Compensated mass balance
29.4% Real-time transient modeling
8.2% Statistical analysis
62.4% Pressure/flow monitoring
2.4% Acoustic/negative pressure wave
16.5% None
3.5% Other

25. Proportion of lines covered with a CPM system?

| | |
|---|---|
| 20 | 0-19% |
| 3 | 20-39% |
| 2 | 40-59% |
| 5 | 60-79% |
| 25 | 80-99% |
| 24 | 100% |
| 19 | Missing |
| **98** | **Total** |

26. How many CPM systems are on your primary SCADA system?

| | |
|---|---|
| 45 | 1 |
| 4 | 2 |
| 3 | 3 |
| 7 | 4 or more |
| 39 | Missing |
| **98** | **Total** |

27. When was your current CPM system installed?

| | |
|---|---|
| 13 | Before 1995 |
| 7 | 1996-1997 |
| 9 | 1998-1999 |
| 4 | 2000-2001 |
| 13 | 2002 or later |
| 12 | Not applicable |
| 40 | Missing |
| **98** | **Total** |

28. How was the CPM system obtained?

| | |
|---|---|
| 16 | Embedded in SCADA system |
| 11 | Developed by company |
| 12 | Not applicable |
| 15 | Developed by a third party provider |
| 5 | Other |
| 39 | Missing |
| **98** | **Total** |

29. Name of vendor who supplied CPM software?

| | |
|---|---|
| 44 | Missing |
| 16 | Not applicable |

| | |
|---|---|
| 2 | Advantica-Stoner |
| 3 | Ed Farmer (EFA) |
| 4 | Energy Solutions |
| 2 | Enviropipe |
| 1 | Fisher Rosemount |
| 2 | Hinz Automation |
| 1 | Honeywell |
| 1 | Linco Electromatic Inc. |
| 2 | Metso Automation |
| 1 | Modisette Associates |
| 1 | Pipeline Studio |
| 1 | Scientific Software-Intercomp |
| 7 | Simulutions |
| 1 | Teledyne Control Applications |
| 5 | Telvent |
| 3 | Valmet |
| 1 | Virtual Pipeline Systems |
| **98** | **Total** |

30. CPM software product name and version?

| | |
|---|---|
| 51 | Missing |
| 17 | Not applicable |
| 1 | Custom built |
| 2 | Enviropipe CPM 1.4 |
| 1 | ES LDS |
| 1 | IRIS 7600 |
| 3 | Leakfinder |
| 2 | Leaknet V 3.12.19 |
| 3 | Leakwarn Classic Model 2.1 |
| 1 | LMS 5.2.2 |
| 1 | Oasys 5.22 |
| 2 | Pipeworks |
| 4 | PLDS 2.5 |
| 2 | PLM |
| 1 | Promap 2.701 |
| 1 | ROC and Intellution |
| 2 | SimSuite Pipeline |
| 1 | SPS 9.10 9.31 |
| 1 | Telvent PLM 6.0.6.3 |
| 1 | Transient Volume Balance |
| 1 | Vector 4.2 PLDS |
| **98** | **Total** |

31. How is your CPM system(s) integrated with your SCADA system? (Check all that apply)

33.8 Embedded in SCADA system
36.8 Collects data from SCADA system
20.6 Separate displays
35.3 Transmits alarms to SCADA system
8.8 Other

32. How were your last 5 system leaks (5 gallons or more) first detected? (Place the number of detections by each method in the blank.)

54 Controller
14 Third party leak detection system
49 Third party
67 Field personnel
12 Excavator
12 Other (describe)

33. Has your CPM system ever been the first indication of a leak?

23 Yes
20 No
33 Not applicable
22 Missing
**98 Total**

34. Did the CPM system designer identify an expected performance in the leak detection thresholds?

25 Yes
14 No
38 Not applicable
21 Missing
**98 Total**

35. What factors have prompted a change in leak detection thresholds? (Check all that apply)

46.5% Nuisance alarms
42.3% Field instrumentation
43.7% Improve detection sensitivity
12.7% Other

36. Is the leak detection threshold dynamically tuned (i.e., changing for steady state operation relative to startup operations)?

| | |
|---|---|
| 30 | Yes |
| 16 | No |
| 29 | Not applicable |
| 23 | Missing |
| **98** | **Total** |

37. How are pipeline leaks isolated? (Check all that apply)

| | |
|---|---|
| 67.1% | Check valves |
| 90.2% | SCADA-operated valves |
| 85.4% | Manual valves |
| 2.5% | Other |

38. How many telemetered data points does your system communicate with?

| | |
|---|---|
| 15 | Less than 50 |
| 3 | 50-99 |
| 8 | 100-499 |
| 6 | 500-999 |
| 16 | 1000-4999 |
| 31 | 5000 or more |
| 19 | Missing |
| **98** | **Total** |

39. Approximately how many dumb (non-programmable) remote terminal units are on your pipeline system?

| | |
|---|---|
| 64 | Less than 10 |
| 10 | 10-49 |
| 4 | 50-99 |
| 2 | 100-999 |
| 0 | 1000 or more |
| 18 | Missing |
| **98** | **Total** |

40. Approximately how many programmable logic controls (PLC) and flow computers are on your system?

| | |
|---|---|
| 21 | Less than 10 |
| 24 | 10-49 |
| 14 | 50-99 |
| 22 | 100-999 |

| | |
|---|---|
| 2 | 1000 or more |
| 15 | Missing |
| **98** | **Total** |

41. What happens if the primary SCADA system shuts down unexpectedly? (Check all that apply)

| | |
|---|---|
| 7.3% | Pipeline shuts down after 2-45 minutes |
| 29.3% | Normal pipeline operations continue indefinitely |
| 61.0% | Backup system becomes operational |
| 56.1% | Dispatch people to monitor |
| 8.5% | Pipeline shuts down immediately |
| 15.9% | Other |

42. What methods of communication does your system use for data communications between the pipeline (pumping stations, field services) and the control center?

| | |
|---|---|
| 1.2% | 1-way radio |
| 48.8% | 2-way radio |
| 8.5% | Cellular |
| 69.5% | Leased lines |
| 29.3% | Microwave |
| 53.7% | Satellite |
| 20.7% | Fiber |
| 21.0% | Other |

43. What backup method of data communication does your system use between the pipeline (pumping stations, field services) and the control center? (Check all that apply. Circle primary method.)

| | |
|---|---|
| 0% | 1-way radio |
| 7.4% | 2-way radio |
| 11.1% | Cellular |
| 19.8% | Leased lines |
| 7.4% | Microwave |
| 15.0% | Satellite |
| 6.2% | Fiber |
| 25.9% | None |
| 48.1% | Dial-up |
| 14.8% | Other |

44. What happens when a primary data communication outage occurs (e.g., an entire satellite hub fails, telephone line into building severed)?

| | |
|---|---|
| 34.5% | Manual switch to backup communication system |

38.1% Automated switch to backup communication system
4.8% Nothing
6.0% Pipeline shuts down immediately
9.5% Pipeline shuts down after 2-45 minutes
57.1% Dispatch people to monitor
6.0% Other

45. Approximately how often does a major unscheduled communication outage occur?

0 Daily
3 Weekly
5 Monthly
22 Quarterly
51 Other
16 Missing
**98 Total**

46. Have your primary and backup communication systems ever failed at the same time?

15 Yes
41 No
24 NA (No backup communications system.)
18 Missing
**98 Total**

47. How is a major communication failure indicated to a controller? (Check all that apply)

78.6% Audible alarm
84.5% Visual alarm
71.4% Data no longer changing
66.7% Data characteristics change (e.g., reverse video, flashing)
7.3% Other

48. How is a communication failure with a field device indicated to a controller? (Check all that apply)

70.2% Audible alarm
81.0% Visual alarm
72.6% Data no longer being updated
70.2% Data characteristics change (e.g., reverse video, flashing)
4.8% Other

49. Approximately how often does a communication outage to a field device occur?

10 Daily

14 Weekly
11 Monthly
22 Quarterly
24 Other
17 Missing
**98 Total**

50. What method of communication does your system use between the control center and corporate systems? (Check all that apply. Circle primary method.)

33.3% Wide area network (WAN)
50.6% Local area network (LAN)
9.9% Internet
27.8% Other

51. Approximately what proportion of controller training time is devoted to the following

| **Initial** | | **Refresher** | |
|---|---|---|---|
| Demonstration (OJT) | 67% | Demonstration (OJT) | 43% |
| Classroom | 5% | Classroom | 9% |
| Films | 0% | Films | 0% |
| Computer-based training | 8% | Computer-based training | 17% |
| Simulator | 4% | Simulator | 7% |
| Manuals | 9% | Manuals | 14% |
| Bulletins | 1% | Bulletins | 2% |
| Handbooks | 1% | Handbooks | 1% |
| Workbooks | 3% | Workbooks | 1% |
| Other | 1% | Other | 1% |

52. Does your company use a simulator to train controllers?

23 Yes
59 No
16 Missing
**98 Total**

53. Name of vendor who supplied the simulator?
3 Developed in-house
13 Stoner/Advantica
3 Telvent
1 Enbridge Technology using Stoner software
2 Energy Solutions International
1 Lignet
75 Missing
**98 Total**

54. What is the simulator product name and version?

| | |
|---|---|
| 2 | Hydraulic Training Simulator 1.0 |
| 5 | Stoner Pipeline Simulator |
| 4 | Stoner Pipeline Trainer |
| 4 | Stoner Pipeline OQ |
| 1 | Stoner Statefinder |
| 1 | QIS |
| 1 | Pipeline Studio |
| 2 | Simsuite Pipeline |
| 78 | Missing |
| **98** | **Total** |

55. Is your simulator generic or specific to your pipeline?

| | |
|---|---|
| 5 | Generic |
| 13 | Specific |
| 6 | Both |
| 74 | Missing |
| **98** | **Total** |

56. Does your company present SCADA alarms in a prioritized fashion?

| | |
|---|---|
| 61 | Yes |
| 21 | No |
| 16 | Missing |
| **98** | **Total** |

57. How many priorities of alarms does your company have?

| | |
|---|---|
| 14 | One |
| 13 | Two |
| 30 | Three |
| 19 | Four or more |
| 22 | Missing |
| **98** | **Total** |

58. How does your SCADA system differentiate different priorities of alarms for controllers (e.g., colors used, flashing, audible, grouping)? “Text”

| | |
|---|---|
| 46 | Colors |
| 31 | Audible |
| 16 | Flash |
| 8 | Grouping |

60. How are leak detection alarms indicated on your display (e.g., location, characteristics of alarm, listed with SCADA alarms)? **“Text”**

| | |
|---|---|
| 19 | Listed with SCADA Alarms |
| 5 | Not Applicable |

61. Does your company review SCADA alarm history (i.e., to refine scope or minimize redundant alarms for controller benefit)? **“Text”**

| | |
|---|---|
| 54 | Yes |
| 26 | No |
| 18 | Missing |
| **98** | **Total** |

60(a). What is the frequency of audits?

| | |
|---|---|
| 8 | Continuous |
| 1 | Hourly |
| 12 | Daily |
| 2 | Weekly |
| 6 | Monthly |
| 1 | Bimonthly |
| 1 | Quarterly |
| 1 | Semi-Annually |
| 3 | Annual |
| 13 | On occasion |

60(a). Who conducts the audits?

| | |
|---|---|
| 16 | Controllers |
| 1 | Senior Controller |
| 3 | Operations Personnel |
| 4 | Control Room Manager |
| 7 | SCADA Group Engineers/Technicians |
| 2 | Measurement Personnel |
| 7 | Supervisors |
| 2 | Engineering |
| 2 | Systems Analysts |
| 1 | System Maintenance |
| 1 | Systems Engineering |
| 1 | Support Staff |
| 1 | Database Technicians |
| 1 | Vice President |
| 12 | Not indicated |

61. What processes does your company use to review your SCADA system (i.e., comparing physical pipeline hardware to SCADA representation [point audits], integrity testing [continuity check between SCADA and field point], controller brainstorming)? Describe the frequency of these reviews, who performs the reviews, and the review process below. **"Text"**

61(a). Who performs these reviews?

| | |
|---|---|
| 1 | Compliance Manager |
| 1 | Controller |
| 1 | Controller, shift supervisor |
| 1 | Engineers, operators, technicians |
| 1 | Field Maintenance, SCADA Team, CC Team lead |
| 5 | Field personnel |
| 1 | Field technicians and database analyst |
| 1 | Field technicians, system engineer |
| 4 | Process control engineer |
| 1 | SCADA Engineer |
| 1 | SCADA Group |
| 1 | SCADA personnel field technicians |
| 1 | Systems and field technicians |
| 1 | Technician and controllers |
| 1 | VP Tech services |

61(b). How often are these audits conducted?

| | |
|---|---|
| 1 | Three Years |
| 5 | Annual |
| 6 | Biannual |
| 3 | Daily |
| 2 | Infrequently |
| 3 | Monthly |
| 1 | Not standard |
| 15 | On occasion |
| 1 | Periodic |
| 4 | Quarterly |
| 1 | Regularly |

61(c). What types of audits are conducted?

| | |
|---|---|
| 3 | DOT required |
| 9 | Management of Change requires point checks |
| 22 | Point to Point Checks |
| 4 | Startup of Pipeline Checked |

15 Additions to the field are checked before going online
5 Comparing values from field to control center
6 Brainstorming by controllers
5 No audits conducted

62. Has your SCADA system been reviewed by the Office of Pipeline Safety?

33.7% No
53.7% Yes, part of a standard inspection
12.2% Yes, part of a records review
11.0% Yes, part of an accident investigation
4.9% Yes, other reason

63. Has your SCADA system controller/human-machine interface been evaluated by an outside consultant?

29 Yes
52 No
17 Missing
**98 Total**

64. Pipeline SCADA systems have allowed more efficient pipeline operations.

73 Strongly agree
9 Agree
2 Neutral
0 Disagree
0 Strongly disagree
14 Missing
**98 Total**

65. Pipeline SCADA systems have allowed safer pipeline operations.

65 Strongly agree
12 Agree
1 Neutral
0 Disagree
0 Strongly disagree
20 Missing
**98 Total**

66. What recommendations do you have to improve SCADA and/or CPM systems?
"Text"

| | |
|---|---|
| 3 | SCADA Intelligence |
| 7 | CPM Improved |
| 3 | Better Backup Communications |
| 1 | Alarm Standards |
| 1 | Complete Open Path Checking |
| 2 | Better Software usability |
| 6 | Better communications |
| 2 | Revised Standard 1130 |
| 1 | Joint Meeting NTSB and Industry |
| 1 | Formal Training |
| 1 | Separate SCADA Network from Corporate Network |
| 3 | More Redundancy |
| 2 | Eliminate False Alarms |
| 1 | OPS Require SCADA |

67. Additional comments regarding safety and SCADA/CPM systems. **"Text"**

- Better operator training on the systems. Integrated simulation and training in the SCADA system. Higher fidelity modeling
- [a comment on question 6] CO2 product is measured in MMCF/Day we transport 600 MMCF/day to 1100 MMCF/day rates
- Dumb RTUs should not be used. PLCs or other programmable devices are capable of safely maintaining system operation or shutdown, should it be required.
- Emphasis on damage prevention, including support for one-call systems and enforcement of one-call laws.
- Our company policy states that the primary protection of our facilities shall be local field devices. Our SCADA system is normally not the primary protective device for our pipelines. Therefore, a loss of communications with the SCADA system does not pose a threat of failure to the whole system.
- RTTM CPMs and trainers are the way to go.