NATIONAL TRANSPORTATION SAFETY BOARD
Office of Rail, Pipeline and Hazardous Materials Safety
Washington, DC 20594

January 17, 2002

Human Performance Factual Report[1]

A. Accident DCA-00-MP-009

Accident Type: Natural Gas Pipeline Rupture and Fire Involving 12 Fatalities

Location: Eddy County Road 725 (aka 260 White Horn Road)
near Carlsbad, New Mexico

Date and Time: August 19, 2000 at about 5:26 am

Operator: El Paso Natural Gas Company
Colorado Springs, CO

B. Investigator

Eric Sager
Human Performance Investigator (HPI)
National Transportation Safety Board
Washington, DC

C. Human Performance Investigation

From August 19 to August 26, 2000, a human performance on-scene investigation was conducted in conjunction with pipeline operations and survival factors investigations. The operations and human performance investigators conducted their on-scene tasks jointly, and no groups were formed. A principal representative of the Human Resources Department at El Paso Natural Gas Company (EPNG) was assigned to assist with human performance information and records requests while the team was on-scene. EPNG was a designated party to the investigation.

D. Summary of Accident

The 30 inch natural gas pipeline (number 1103) owned by EPNG near the Pecos River in Carlsbad, New Mexico ruptured between the Keystone and Pecos River stations on August 19, 2000. The night controller who was operating the south mainline was finishing preparations to turn the shift over to the oncoming day controller. At about 5:26 am[2] SCADA alarms began to annunciate indicating

[1] This report was prepared subsequent to receipt of technical review information from EPNG dated October 10, 2001.

[2] All clock times identified in this report are shown in Mountain Daylight Time (MDT). Although MDT was used seasonally at EPNG's control center in El Paso, Texas, their SCADA time stamps remained in Mountain Standard Time (MST). In order to provide a uniform time line for all control center activities included in this report, the HPI advanced SCADA

two Pecos River station compressors were shutting down along with low suction pressure for the station. The controller called out a station technician who checked the station and reported back that the damage was in a pipeline. Other technicians responded to the scene and the flow of gas was stopped by manually blocking in the damaged section of pipe. In the fire that ensued, six persons were found deceased at the site, and six injured persons were transported to hospitals for medical care, all of whom were fatally burned.

E. Human Performance Factual Information

Overview of EPNG Control Center, Damaged Pipeline, and Stations

The EPNG pipeline control center was located in El Paso, Texas. Most pipeline monitoring and control activities for the control center were automated using a centralized supervisory control and data acquisition (SCADA) system. The pipelines being controlled from the center consisted of several lines divided into two major systems, the south and north mainlines. Each system was operated by one controller. A coordinator was assigned to assist the two controllers and perform administrative oversight and backup assistance when needed.

The control center operates with two 12-hour work shifts a day. The SCADA was set up to enable the display of the same event screens for both mainlines at each of the three work consoles. Controllers (and the coordinator) could monitor conditions and events for their assigned system from one generic control center screen, and select alternative screens for information at locations along their respective systems. The coordinator stated that he was the person in charge of the shift.

The Pecos River station was controlled remotely from the EPNG control center. The damaged section of the 1103 pipeline was about 5,860 pipeline feet upstream from the Pecos River station. According to EPNG control center records, the pipeline was operating at about 675 psig at the time of the rupture, and its maximum allowable operating pressure was 837 psig.

The Keystone station was the first compressor station upstream from the damaged part of the pipeline. Two other compressor stations, Eunice and South Carlsbad were upstream from the Pecos River station and were delivering gas toward Pecos River. During the line balancing phase of the recovery activities after the rupture, flow from the Eunice and South Carlsbad stations was rerouted. Keystone and Eunice were manned stations. The South Carlsbad station was remotely monitored by the El Paso Field Services facility in Farmington, New Mexico.

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time in the text from MST to MDT.

Performance of the South Mainline Controller

Workload Prior to the Rupture -- At about 5:50 pm on August 18, 2000 the controller for the south mainline reported for the night shift and took over operating duties from the day shift controller 10 to 15 minutes later. According to the south controller, the off going controller did not pass along any operating abnormalities.

The south controller's activities before the rupture were obtained for the investigation from a shift log for August 18, 2000[3] from the shift turnover until 5:35 am,[4] system events printed by the SCADA for the same time period, and from interviews taken for the south and north mainline controllers and the shift coordinator. The first action entered in the log for the south controller was his authorization at 6:04 pm for an operator at the Casa Grande station to start a compressor. At 6:05 pm, the control center received a telephone alarm from the Prewitt plant.[5] In response, the south controller called a representative of the contractor responsible for the facility informing him that the control center had received the alarm.

At 6:15 pm the south controller was involved with a compressor suction alignment change during a delivery to the Oasis pipeline[6]. The log also shows the south controller authorized an employee to go to the Waha facility and change a line up of valves. The south controller said that at 6:50 pm, he directed the Keystone station operators to reduce the delivery rate to Waha because of the earlier valve alignment changes made upstream. The Keystone operators' log shows that all Waha flow was switched to Pecos River (Attachment 2 - Keystone Mainline Station Time Line). Subsequently at 7:15 pm, the south controller called the Waha station to warn plant personnel that water content in the gas was exceeding 7 pounds,[7] and the plant dehydrator needed to be checked. The south controller stated to investigators that a plant technician informed him that they turned up the temperatures on the reboilers and corrected the problem.

The next recorded action is the south controller's telephone callout for an employee to restore AC power at the Laguna station. The problem was logged as corrected at 9:55 pm. The south controller instructed the operator at the Deming station to start another compressor at 8:55 after the operator called the control center about a low differential pressure at the station. At 9:15 pm the

[3] Entries in the log were for the 12-hour shift beginning at 6:00 pm on August 18, 2000 and ending at 6:00 am the next day, August 19 (Attachment 1 -- Night and Day South Controllers' Shift Log).
[4] The EPNG shift log provided entries until the fire was reported by the employee calling from his home.
[5] Prewit is a superfund site, and was operated by a contractor as a gas treatment facility. EPNG controllers were responsible for notifying the contractor if they received an alarm indicating that equipment had failed at the facility.
[6] Oasis Pipeline Company is an intrastate pipeline operating from west to east Texas. The company is headquartered in Houston.
[7] Seven pounds refers to a maximum water vapor standard of 7 pounds H_2O per MMscf (million standard cubic feet) in the gas.

south controller authorized the Plains station operator to take one compressor off because deliveries out of that station were slowing, and at 10:45 pm the south controller cut back the delivery rate from Peach Ridge Pipeline, Inc.[8] The south controller authorized a Eunice station technician to stop one compressor at 11:23 pm. The Keystone operators' log shows that at 9:05 pm the south controller directed station personnel to switch their flow from Pecos River back to Waha. Then at 1:25 am, the south controller authorized stopping an unneeded compressor at the Plains station. No further activities were entered in the log until the Pecos River station alarms starting at 5:26 am. In the meantime, the south controller indicated he was monitoring and clearing alarms as they occurred with their usual regularity. No ones' workload during this time was described as intense. The coordinator characterized the evening at the control center as a normal one.

Recognition of the Rupture -- The south and north mainline controllers and the coordinator indicated that when the rupture occurred, everyone was seated at their desks monitoring pipeline events on the SCADA. In addition, each person was finishing up details to turn the center over to the day shift. The north controller said that control center work was constant, characterizing it as the usual continuous surveillance of the pipelines. The south controller said that things were pretty uneventful until the blowout.

The south controller entered 5:26 am as the time for the first alarm received for the problem at the Pecos River station. According to the SCADA event log, the first alarms from the Pecos River station pertaining to the rupture were plus and minus turbine speed rates of change (ROC) for the number 3 compressor at 5:26:49, followed by minus suction and discharge pressure ROC alarms for the number 2 compressor at 5:27:01 am.[9] Alarms were (time) stamped at 5:27:37 and 5:28:39 am for the shutdowns of the number 1 and number 2 compressors. Also, at 5:27:37 am alarms for the number 1 compressor were stamped for minus suction and discharge pressure ROC alarms, plus and minus turbine speed ROC alarms, and a low speed alarm. According to event log entries, the south controller acknowledged ROC alarms for compressors 1 and 2 at 5:27:52 am. Trip alarms for compressors one and two were acknowledged at 6:06:13 and 6:06:05 am respectively. Acknowledgements of the number 3 compressor alarms first alerting the south controller of a problem at the Pecos River station were stamped at 6:05:36 am.

The south controller indicated in his statement to investigators that the first alarm pertinent to a possible rupture was a minus ROC for the Pecos River station suction pressure. The alarm was stamped in the SCADA event log at 5:27:45 am, about 8 seconds after the number 1 compressor tripped.

[8] Peach Ridge Pipeline Inc. is a gas gathering and processing system for the delivery of residue gas located in Crockett County, Texas.

[9] Selected pages from the system events log with pertinent SCADA entries are in Attachment 3 -- System Events Log.

According to the coordinator, it was almost a daily occurrence to lose compressors on the south or north mainlines. The south controller also said that it was not uncommon for units to go down.

The south controller indicated that he intended to draw everyone's attention to the situation at the Pecos River station. The north controller recalled that he first became aware of the problem when the south controller said, “it looks like we lost Pecos River number one” as the alarm for the tripped number 1 compressor came in. The north controller who was watching the same screen at his desk replied back that, "it looks like you're losing another [number 2 compressor] right now." Thereafter, the south controller said that he verbally relayed aloud what took place on his screen, and he expected the others on the shift to know about the problem. The south controller indicated that he confirmed that the coordinator was aware of the problem after the communication outage with the station was restored, and the south controller declared that "we've got a problem."

The south controller said that he had started to poll the system for station and compressor data to update the screens as soon as the first unit shut down. The system events log indicated that he executed polls at the following times:

5:28:20 am for Pecos River station data (demand scan)[10]
5:28:28 am for compressor number 1 data (demand scan)
5:28:28 am for compressor number 2 data (demand scan)
5:28:36 am for compressor number 3 data (demand scan)
5:28:52 am for Pecos River station data (interleave)
5:29:00 am for compressor number 3 data (demand scan)
5:30:36 am for compressor number 3 data (interleave)

The south controller explained that they obtained data on compressors 1 and 2 but none was returned for compressor 3.[11] He said that while he was issuing the demand scan polls, the control center lost communication[12] with the Pecos River station. He recalled that this was after the number 2 compressor tripped. The south controller indicated that at this time he was hoping the data from the Pecos River station were the result of a computer problem rather than abnormal conditions. He explained that sometimes the control center computer rebooted and [inaccurate] alarms were displayed. Within a few minutes of these

[10] The normal control center computer scan of the pipeline system requires four minutes. The polls issued by the south controller were *demand scan* or *interleave* commands, both of which were intended to provide data without waiting for the normal scan of the system. Demand scans were computer requests to obtain a one-time data report from the polled station or equipment, interleaves were computer requests to obtain data reports as frequently as possible from the polled station or equipment over a period of time specified in the request (25 minutes each according to the system events record). The south controller said that the data returned from the *demand scans* for the units included unit suction and discharge pressures and various compressor operating parameters. He did not mention the *interleaves* during the interview.

[11] The first alarms preliminary to compressors 1 and 2 shutting down were ROC pressures for compressor 3.

[12] According to the south controller, loss of communication refers to the station not responding to polls for data, and locking up of numbers for the last data received. This condition also known as off-scan, displays the alarms with inverted colors for the text and background (inverse video). The EPNG SCADA does not record inverse videos displays.

displays, however, controllers would see that pipeline conditions were normal. Nonetheless, the south controller indicated that he seemed to know instinctively that something had happened at the station.

While the computer was locked for the Pecos River station, the south controller called out a lead technician to check the station out. The south controller recalled that he informed the lead technician that they had a low suction pressure at the station.[13] Although the lead technician recalled being told during the call there were two [compressors] down, the north controller acknowledged later that the controllers did not know for certain if the units were actually down during that call.

At about 5:27, the south controller indicated that he saw unit pressures on the screens change (as the SCADA updated from locked status for the Pecos River station), and at this time he believed that the condition was a likely rupture. The south controller said that the low suction pressure for the Pecos River station was unusual after the compressors had shut down. He also noted that he saw increased gas volume coming in from the South Carlsbad station. At this time, the south controller called the lead technician back to warn him that the problem at the station was a major one and probably was a blowout. Overall, the south controller estimated that three minutes elapsed from the time that the first compressor stopped until he understood the SCADA alarms were credible.

The south controller said he then directed operators at the upstream Keystone and Eunice stations to reduce their output by taking three compressors off each. The Keystone operators' log shows that at 5:30 am, the south controller informed them that Pecos River was down, and that at 5:40 am operators took off their remaining compressor. The south controller identified his last call, before being relieved by the day shift controller, as one to the El Paso Field Services (EPFS) in Farmington. The south controller told them that they needed to send someone to the South Carlsbad station to get their turbines off.

The coordinator indicated that everyone at the control center began working together after the first Pecos River station unit tripped. He said that he had looked to two indices for understanding the situation; pressure drops at the Pecos River station and at the check meter for the South Carlsbad line. According to the controllers, the coordinator gave directions for persons they should notify on the telephones about the situation. The south controller indicated that the coordinator did not give him instructions for operating any pipeline equipment, and that it was his own decision to call out to the lead technician to check on the station. The north controller noted that after the second call had been made to the lead station technician, the shift coworkers still weren't sure there was a major problem but they were following through in the interest of safety. The north controller also said that the coworkers discussed the

[13] The south controller explained that when a station shuts down, its suction pressure is expected to be higher than normal - not lower.

possibility of a rupture before the communication loss was restored. He indicated that everyone had their console copy of the *Operating and Maintenance Manual* open before the south controller saw the SCADA update after the Pecos River station lockup.

The south controller said he was relieved by the day shift controller at about 5:50 am but he remained at the control center to assist with activities until about 8:00 am. According to entries in the relieving day shift controller's log, the control center directed the Keystone station operators to reroute gas to Waha and raise the flow to maximum, (i.e., away from the Pecos River station). The Keystone station log entries showed that at 5:30 am the south controller informed them that the Pecos River line was down. Their next entry was the day shift controller's request to shut down their station at 6:00 am.

EPNG Written Directives for Controller Response

Guidance to controllers for recognizing a pipeline rupture was set forth in the *Pipeline Control Operations Manual* [Revised date: 11/21/95, LINEBRK.DOC].[14] This manual was provided to new controllers during their training period. The manual states,

> ***Large leaks or ruptures of the pipeline can be detected by Pipeline Control personnel by monitoring the available pressure reading at points along the pipeline. In most cases, the only pressures available are compressor stations suction and discharge pressures. Under normal operating conditions, the pressure drop from the discharge of one station to the suction of the next station will remain within a certain range. A large loss of gas from the pipeline between two stations will result in lower pressures at both points. There may also be an increase in the flow rate at the upstream station's discharge, and a decrease in the flow rate into the downstream station.***

Also, the manual advises in an outline format that several things will happen which can be detected in the control center. These were,

> ***1. Sudden drop in discharge pressure at one station and a drop in suction pressure at the next downstream station.***
>
> ***2. Sudden increase in flow rate through one station and a decrease in flow rate through the next downstream station.***
>
> ***3. Rate of Change (ROC) alarms from the stations will also indicate a problem.***
> ***a. Suction Pressure***
> ***b. Discharge Pressure***
> ***c. Turbine Speed***
>
> ***4. If suction pressure at the downstream station falls low enough, the station will [emergency shut down].***

[14] The November 21, 1995 version of the manual was in use at the time of the accident.

5. Sudden changes in pressures or flows may cause turbines to ESD on vibration, etc.

Guidance continues that when these indications are seen,

1. Note the time.
2. Check for other indications of a line break for verification.
3. Order shutdown of compressors, closing of valves, etc., to isolate the leak.
4. Contact the appropriate area operations personnel and inform them of the situation.
5. Adjust horsepower upstream and downstream to accommodate safe pressures and flows.
6. Determine exact location via pressures, operations personnel search, and/or reports from citizens, etc.
7. Assist as necessary in calling law enforcement and other emergency agencies.
8. Contact the appropriate Division Compliance Engineer or alternate, and Codes and Standards [personnel]. Do this AS SOON AS POSSIBLE. Codes and Standards must determine if the incident is reportable to DOT, and if so, call them WITHIN FOUR HOURS of the time Gas Control receives the first notice.
9. Adjust other compressor station operations and contact connecting pipelines and consumers to redirect the flow of gas as necessary to maintain deliveries (if possible) and to protect other portions of the line.
10. Maintain contact with Operations and all affected customers until repairs are completed, or until sufficient gas is re-routed to return to normal operations.
11. Complete "Failure Information for Gas or Liquid Facilities" form. Whoever takes the report must sign the form. Forward copies to Compliance and Codes and Standards.

The manual also included a memorandum dated January 28, 1992 to coordinators and controllers requiring various alarms received on the SCADA be reported to operations personnel, (i.e., control center shift coordinators). An attachment listed 14 alarms to report that occur with the station *ON* or *OFF*; four alarms were indicated that occur only with the station *ON*. The memorandum was co-signed by the pipeline control, operations control department manager and administrator. An emergency shutdown [for any compressors] was the second alarm shown on the *ON* or *OFF* list.

Printed guidance for controllers to assess, classify and report pipeline leaks was provided in the *Operating and Maintenance Manual, Leak and Failure Reporting.* Call lists with telephone numbers were attached to the manual.

Controller Work and Rest Schedules

Control Center Shift Schedule -- Controllers and coordinators worked 12 hour shifts with starting times a few minutes before 6:00 am and 6:00 pm.[15] They were assigned to a three or four consecutive day work week depending

[15] According to EPNG, controllers customarily arrived early to be briefed on events during the previous shift before relieving the off-going controller.

upon their respective position in the control center schedule. Changes for day and night shifts for controllers or coordinators were made at the start of the work week after several consecutive days of off-duty time. The schedule showed that controllers alternate between the north and south desks every five weeks. According to the administrator, pipeline control, operations control department two controllers and a coordinator are assigned to work together for about a year. Composition of the shift teams were determined by the manager and administrator for the center.

South Controller's Fitness for Duty -- On the morning of the accident the south controller was working the first night following a week of day shift work. He recalled reporting to the control center that Friday evening at the customary time of about 5:50 pm. The controllers' schedule for the week of August 14, 2000 showed that Friday night was the south controller's third week on the south mainline, and the first of four consecutive nights before he returned to another week on days.

The south controller recalled his activities for the three days prior to the accident shift. On Wednesday, he had gotten up at about 7:00 am and spent most of the day refinishing an item of furniture. He recalled having a sandwich for lunch, and took his children to church at about 6:30 pm. Later he took the family to a fast food restaurant for supper. During the rest of the evening, he worked on personal business affairs, watched television, and then went to bed about 10:30 pm. The south controller said that he normally sleeps well and noted that he had a new bed mattress. He usually needs an alarm to wake up after his main period of sleep.

On Thursday, the south controller awakened at about 5:30 am to drive his daughter to school at 6:30 am for an activities practice session. He returned home to take his son to school at 8:00 am, and enjoyed a relaxing day that included shopping at the local mall. He indicated that he may have eaten lunch at the mall. When he returned home, he did some investment research, and at about 3:15 pm picked up his son from school. The south controller said that the family had a full dinner at about 5:30 pm. In the evening, he monitored his children's homework activities, watched television, and probably went to bed before 10:00 pm.

On Friday morning, the south controller said he slept later than usual because he was working that night. He recalled getting up at about 9:30 am and had a breakfast described as late and substantial. He did not eat again until dinner. The south controller could not recall his activities during the day except for taking a nap from about 2:00 pm until 4:30 pm.

He said that he gets his rest and sleeps well night or day. The south controller indicated that his ability to sleep during the day enabled him to do shift work.

General Health and Medications -- The south controller rated his personal physical condition as good. He said he exercised by walking and playing golf. He stated that he occasionally had shoulder pain and medicated the condition with Motrin. The south controller denied being treated for any medical conditions at the time of the accident, and said he had taken no medications (over-the-counter or prescribed) within four days of the accident. He indicated that he usually drank four to five cups of coffee during a work shift but withdrew after 4:30 am and pm. He stated that he does not use tobacco, drink alcohol or use drugs of abuse.

Toxicological Testing

RSPA Post-Accident Alcohol Test Requirements -- (a) Post-accident. (1) As soon as practical following an accident, each operator shall test each surviving covered employee for alcohol if that employee's performance of a covered function either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. (49 CFR § 199.225)

RSPA Post-Accident Drug Test Requirements -- (b) Post-accident testing. As soon as possible but no later than 32 hours after an accident, an operator shall drug test each employee whose performance either contributed to the accident or cannot be completely discounted as a contributing factor to the accident. (49 CFR § 199.11)

Operator's Toxicological Tests for Control Center Night Shift -- EPNG records and interviews obtained during the on-scene investigation indicate that the south and north controllers and the coordinator were tested for prohibited drugs[16] after the accident. Initially a decision was made not to test the control center employees based upon EPNG's interpretation of 49 CFR §199.221 and §199.11, and the "facts known to them on the morning of August 19, 2000. See Attachment 1 for information about EPNG's initial testing decision. According to the south controller, at about 4:30 pm Sunday August 20, 2000 his immediate supervisor (the administrator, pipeline control, operations control department) notified him by telephone of the tests. He was informed that the collections were for post-accident drug tests, and the procedure was to be voluntary on everyone's part. Specimens were collected after the controllers and coordinator arrived at work on Sunday, and were begun at about 6:08 pm. The collections were done in a restroom at the control center facility. The coordinator said that his collection was on Saturday evening but the contractor's lab reports showed his collection was on Sunday, August 20, 2000.

The EPNG substance testing contractor, Behavioral Training Institute, Inc., performed the collections and forwarded the specimens to Universal

[16] Prohibited drugs included in the tests were marijuana, cocaine, opiates, amphetamines, and phencyclidine as required by RSPA post-accident test rules. (49 CFR § 199.3 Definitions.)

Toxicology Laboratories in Midland Texas. The results were reviewed by an MRO at SurgiMed, P.A. in El Paso, Texas. The test results for the prohibited drugs were negative. Safety Board investigators were informed of the results on Monday, August 21, 2000 by an EPNG official. See Attachment 4 for redacted copies of the test results returned to EPNG by the MRO. See Attachment 5 for EPNG's explanation for their initial decision not to test control center personnel.

Background and Work Record for the South Controller

The manager of the pipeline control, operations control department said the control center service time for most controllers averaged about 11 years. There were 10 controllers at the center all of whom were qualified to operate either the south or north mainlines. The company stated that two controllers were ranked as senior controllers with a minimum of "approximately" two years of experience as entry-level controllers. The remaining eight controllers were identified as systems controllers having a minimum of "approximately" five years of experience as senior controllers.

The south controller (age 45) was a systems controller, the highest level at the center for the controller position. He had 11 years of gas pipeline control experience and was advanced to the systems controller level in 1997. Company records showed that he started with EPNG as a plant helper in 1977. He said that he worked at six different compressor plants. He had participated in an EPNG job progression training program advancing through positions to a senior technical position. From 1992 to 1996, he worked as a systems dispatcher at Mojave Pipeline Operating Company, a subsidiary of the El Paso Corporation. He returned to EPNG and remained at the control center through the date of the accident.

His immediate supervisor at the pipeline control, operations control department said that the controller was a "highly rated" employee at the center. He said that the south controller was dependable, technically competent and personally well-fitted to the job. His performance reviews were consistently favorable, and there were no disciplinary actions noted. In 1997 the controller had participated in training on the coordinator's desk, and was apparently qualified to handle a coordinator's shift (according to his 1999 performance review). He had been the controller on duty when the Dumas pipeline was damaged during company drilling operations and resulted in a leak.

EPNG Training, Currency and Selection of Controllers

According to the manager of the pipeline control, operations control department, controllers were selected mostly from the work force of El Paso field technicians. He noted that three coordinators had backgrounds in scheduling and dispatching before they came to EPNG. The manager said that field technicians typically advance through three levels, from entry level technicians, to senior technicians, to chief or lead technicians. He said that these

advancements were based on the employees' skills and knowledge acquired on the job.

The manager indicated that entry level controller training started with background information in company pipeline operations and the control center. This was conducted by control center controllers, the administrator for the center or the manager. An information manual was usually provided for this orientation. The manager indicated that training was targeted to the needs of technicians already having local knowledge acquired during their experience in field operations.

After the orientation phase, an entry level controller was assigned to a trainer controller (usually a systems level controller or coordinator) with whom he worked side by side for at least one month. This working phase of the training was identified as OJT. The basic documents used for training of pipeline control activities were the *Pipeline Control Operations Manual*, and the *Operating and Maintenance Manual*. EPNG does not use computer simulation methods for controller training.

Training guidance was also provided by the *EPNG Pipeline Control Task Verification List*, a two-page document showing activities and knowledge areas in which controllers were expected to be proficient. It included schedules used at the control center, reports and logs, the SCADA system, various computer programs and applications, materials at the control center for controllers' reference use, and operating information about EPNG and other interconnecting pipeline systems.

Controllers assigned as trainers were to discuss abnormal operating conditions with new controllers. In addition, abnormal conditions were covered in the *Pipeline Control Operations Manual*. According to the manager, new controllers were paired during training with only the center's best controllers. The administrator noted that there had been no "washouts" for new controllers, and he attributed their success to the control center selection procedures.

Proficiency for all controllers on both pipeline systems was maintained by alternating their assignment every four or five weeks to the north or south mainlines. The complete rotation for each controller through the schedule provided one week where he was not assigned to a shift. During this break from pipeline operating activities, the controllers performed various training tasks such as improving computer skills, completing a special project for the center, or taking trips to visit compressor stations in the field. Controllers sent on the field trips reviewed station emergency response procedures or observed equipment operation and maintenance. Controllers were required to write a one-page report for each trip, and written records of the trips were to be kept in each controller's training folder. The HPI reviewed one such report.

The manager said that controllers and coordinators had participated in formal training offered by vendors. He said that in the past, EPNG had sent controllers to classes in gas controller training, but the controllers' comments about the classes were not favorable and vendor training was discontinued.

The manager indicated that departmental policy required controllers and coordinators to attend at least four safety meetings a year. According to information received from EPNG in response to a draft of this report, the meetings were to be attended during off duty time, and were scheduled to enable the maximum possible attendance. The manager identified various safety meeting topics during a typical year as items from the *Pipeline Control Operations Manual*, pertinent DOT regulations, SCADA system alarms, company emergency response procedures, and drug awareness issues. Meeting length averaged 2 hours. EPNG comments also indicated that during each evening shift, the coordinator conducted a brief safety meeting with his controllers. These meetings were said to last 20 to 30 minutes. Controllers also submitted at least one safety audit report each year in which they identified an unsafe condition or activity that had come to their attention.

According to information received from EPNG in response to Board written questions, formal exercises simulating pipeline accidents have been conducted, several of which involved local emergency response agencies. The most recent exercise was in 1997. In addition, controllers and coordinators at the control center participated in simulation or mock emergencies in conjunction with field personnel training each year.

Training records for controllers are reviewed annually by the manager and administrator of the pipeline control, operations control department. According to the manager, individual training needs are discussed directly with each controller. At the time of the accident, the training department for the El Paso parent company in Houston provided assistance to EPNG with maintaining training records, keeping aware of various training regulations, and identifying learning resources for employees.