DOT	US Department of Transportation
PHMSA	Pipelines and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety
	Western Region

Principal Investigator	Hossein Monfared
Regional Accident Coordinator	Peter J. Katchmar
Region Director	Chris Hoidal
Date of Report	03/14/2013
Subject	Failure Investigation Report – El Paso-Mojave GT 2012-5-2

Operator, Location, & Consequences

Date of Failure	05/02/2012
Commodity Released	Natural Gas
City/County & State	Arvin/Kern, California
OpID & Operator Name	4280 & El Paso Natural Gas Company
Unit # & Unit Name	8325 & OO-Mojave Pipeline Operating Company (Mojave)
SMART Activity #	139472
Milepost / Location	MP 118+1904/Line 1901 at Bifurcation Point
Type of Failure	Equipment Failure/Relief Valve Structural Support Failed During Relief Event
Fatalities	0
Injuries	0
Description of Area Impacted	Operator Controlled Property and Small Impact to Nearby Orchard
Property Damage	$512,000

Executive Summary

On May 2, 2012, at 08:30 a.m. Pacific Daylight Time (PDT), a reportable incident occurred on the Mojave Pipeline at a facility known as the "Bifurcation Point," which is about three miles southwest of Arvin, CA, on the edge of a cherry orchard near the Sycamore Canyon Golf Course. The accident resulted in the release of natural gas into the atmosphere and the complete structural failure of the overpressure protection support system at the facility.

An analysis of the failure indicated that the structural support system for the relief valves was poorly designed and was insufficient to support the loads imposed during a relief event. According to the operator, this was the first relief event to ever occur at this facility. The relief valves numbered #601, #602, #603, and #604 were set at 942, 951, 959, and 970 psig, respectively. The points at which these valves were set were based on the relief valve test report dated May 31, 2011. The pressure at which the event occurred was 916 psig.

System Details

The Mojave Pipeline Operating Company, LLC (Mojave) currently operates as a subsidiary of Kinder Morgan, Inc. Previously, it was owned and operated by El Paso Pipeline Corporation. The Mojave Pipeline was built and commissioned in 1992. The transmission line originates at the Topock Compressor Station at the California/Arizona border as a 30-inch outside diameter (OD) pipeline and runs approximately 143 miles west to Daggett, CA. At the Daggett compressor station, Kern River Gas Transmission Company's natural gas transmission pipeline system interconnects with the Mojave Pipeline from the north. From Daggett, the Mojave Pipeline is a 42-inch OD pipeline and runs west to a location near the city of Arvin, CA, called Bifurcation Point. At this location, the pipeline splits into two lines: the Mojave Line No. 1901, which is also known as the West Lateral, and the Mojave Line No. 1902, which is known as the East Lateral.

This pipeline junction is across a dirt road from the Sycamore Canyon Golf Course and is located at the edge of a cherry orchard. The main purpose of this station is to receive natural gas and direct the gas down the East and West Laterals to feed electrical generation plants for Southern California. The station also provides overpressure protection for all of the pipelines. This facility is fenced and includes a mainline block valve on Line 1901 upstream of the tee that connects Line 1901 to Line 1902.

Downstream of the tee is a vault containing pressure and internal corrosion-control monitoring equipment for Line 1901. A second vault containing pressure and internal corrosion-control monitoring equipment for Line 1902 is also present downstream of the tee. There is a pipe header and pressure relief valves immediately downstream of the second vault on Line 1902. Also downstream of the second vault is a mainline block valve #323 and a pig trap assembly. There are also other necessary facilities and equipment used for remote operation and monitoring of the pipelines at this location.

The Mojave Pipeline from Topock Compressor Station to Bifurcation Point has a maximum allowable operating pressure (MAOP) of 1200 psig. Downstream of Bifurcation Point, Lines 1901 and 1902 have a MAOP of 930 psig. The four relief valves are connected to Line 1902 via a header. These relief valves protect the lateral line that leaves Bifurcation Point from exceeding its MAOP. The header was fabricated by welding four 30-inch x 16-inch tees together and then welding a 16-inch x 6-inch concentric reducer to the branch of each tee. The resulting four 6-inch branches of the header (which was below grade) were extended with pipe above the surface.

Each assembly includes a 16-inch x 6-inch concentric reducer followed by 6-inch pipe that extends the outlets above grade, and 6-inch class 600 flange. Raised-face flanges were welded to the pipe extensions, and full-opening 6-inch flange-by-flange ball valves were bolted to each branch of the header. Spool pieces were bolted between the ball valves and pressure relief valves. Lastly, 8-inch vent pipes were bolted to the pressure relief valves. These pipes were designed to vent gas horizontally then direct it vertically. The 8-inch vent piping for these assemblies was supported by two vertical structural members and a horizontal crossbeam. All three of the structural members were fabricated from six W15 I-beams that were welded together and bolted to a concrete foundation.

Events Leading up to the Failure

Mojave Pipeline is operated remotely at the El Paso Control Room in Colorado Springs, Colorado, which is in the Mountain Time Zone. Bifurcation Point is located in the Pacific Time Zone. Both times are provided for convenience. Presented below is a chronology of events leading to and immediately after the failure event:

On the morning of May 2nd, at about 4 a.m. Mountain Daylight Time (MDT), (3 a.m. Pacific Daylight Time (PDT)), gas controllers for Mojave began noticing a drop in line pressure as measured at main line valve (MLV) #323, which is located at Bifurcation Point. Approximately one hour later, Kern River took its upstream compressor station at Good Springs offline. The line pressure on the Mojave pipeline west of the interconnection with Kern River Pipeline at Daggett, CA, continued to drop at a slow and steady rate. It is understood that at approximately 5:45 a.m. MDT (4:45 a.m. PDT), a more significant drop in pressure was observed at MLV #323 as reported by Mojave Gas Control. Mojave Gas Control then contacted an operations technician in the Bakersfield area to investigate the dropping pressure.

At approximately 9:20 a.m. MDT (8:20 a.m. PDT), Mojave Gas Control received a call from the Sycamore Golf Course that reported blowing gas in the area. Mojave personnel in the field requested that the El Paso operations control center close MLV #323 on the Mojave pipeline, the valve on Line 1901 downstream of Bifurcation Point, and MLV #601 at Bifurcation Point downstream of the leak on Line 1902. Mojave reported the failure to the National Response Center (NRC), Report No. 1010322, on May 2, 2012, at approximately 10:28 a.m. MDT (9:28 a.m. PDT). Following these actions, the line had fully blown down by about 1:30 p.m. MDT (12:30 p.m. PDT). After the lines were fully shut in, personnel inspected the Bifurcation Point facility and determined that all four relief valve assemblies were damaged.

Emergency Response

PHMSA's Western Region received an email from the National Response Center on May 2, 2012, at 10:44a.m. MDT (9:44 a.m. PDT). PHMSA's Western Region had personnel performing inspections in the area of the release and redirected an inspector to respond to Mojave's Bifurcation Point to initiate an investigation into the event. The inspector arrived at 4:00 p.m. MDT (3:00 p.m. PDT). After looking around the site, it was apparent that the relief valve support system failed, which caused major damage to all four relief valves. PHMSA's inspector monitored the operator's gathering and removal of the relief valves and structural support system. Plans were made to transport failed pipe, structural members, and the relief valves to Houston, Texas, for forensic testing. The cause of the relief event, however, was still unknown.

On May 8, 2012, PHMSA issued a Notice of Proposed Safety Order (Notice) to Mojave Pipeline Operating Company. The Notice required certain safety measures to be performed, including pressure reduction, overpressure protection, and forensic testing, under PHMSA's monitoring. Stress Engineering Services (SES) out of Houston, Texas, was contracted by the operator to perform a failure analysis and a stress/flow analysis. Tyco/Anderson Greenwood and Crosby was contracted to complete the relief valve testing and forensic analysis. At the conclusion of the testing, each entity submitted a separate report detailing their analysis and conclusions. Mojave combined those reports into a root cause failure report that was submitted separately. All reports are attached.

Summary of Initial Start-up Plan and Return-to-Service, Including Preliminary Safety Measures

Because the Mojave Pipeline delivers natural gas to electrical generation plants downstream of Bifurcation Point, the effort to resume gas operations was considered critical. Immediately after the event, Mojave engineers, working in conjunction with El Paso and Kinder Morgan engineers, checked the Mojave Pipeline in particular and all El Paso pipeline systems, broadly, for similar relief support installations. Having found none, they began a redesign of the relief system at Bifurcation Point. Also, El Paso began work to install temporary bypass piping around the failed relief header.

On May 4, 2012, PHMSA informed Mojave that they could start a purge of Bifurcation Point's bypass piping and provide temporary overpressure protection by manning the manual mainline valve 24 hours a day, 7 days per week, until the new relief system was in place. Natural gas service was restored on May 4, 2012, at a 10 percent pressure reduction from the pre-failure pressure.

PHMSA worked with Mojave on the redesign of the relief system to ensure the new design was of sufficient capacity and could support the anticipated internal forces created by a relief event in the future. PHMSA engineers worked closely with the operator to review and approve plans within a short and expedited time frame.

Investigation Findings & Contributing Factors

PHMSA reviewed all of the reports submitted by SES, Tyco/Anderson Greenwood and Crosby, and Mojave Pipeline Operating Company. In section "7.2 SES Stress/Gas Flow Analysis" of the Mojave Report entitled, "FINAL REPORT Mojave Bifurcation Event - Root-Cause Analysis," the report discusses SES's conclusions:

> "This study showed that the vent piping would overstress due to predicted hydrodynamic forces without adequate support from external means. Additionally, there is a high degree of likelihood that the piping would overstress with the insufficient support provided in the event that even one of the relief valves were to vent. The structure provided did not have sufficient stiffness and allowed the propagation of loads from any one vent pipe to the adjacent pipe vents. Additionally, the support structure had undesirable design features. The analyses by SES indicate that the structure was not adequate to support the predicted loads and the models

indicated highest stress concentrations and predicted overstressing in the locations that the actual failures occurred."

The report goes on to state:

> "While SES hypothesized the failure could have been caused first by PSV-603 based on oil residue in the piping, it is impossible to conclusively state which valve actuated first and SES's sequence is a hypotheses based on speculation. Regardless of the first sequenced valve, the primary and contributing factor of the failure was the inadequate support as it was determined that any valve relieving would lead to failure of the support."

In section "9.2 Root Cause," the report states:

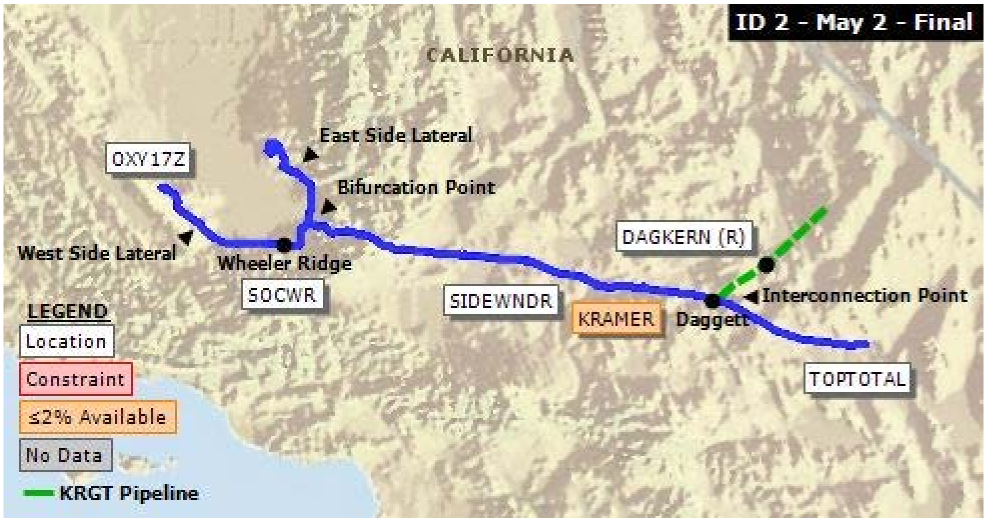
> "Ultimately, the inadequacy of the structural support provided at this installation and its failure allowed for the failure of the piping systems it was intended to protect.
>
> - Undersized structural members in support to withstand predicted forces of venting
> - Incorrect orientation of support columns and cross member (weak axis exposed)
> - Connection between tail pipe and support didn't insure transfer of forces"

PHMSA agrees with the analysis provided in all of the forensic analysis reports. It is apparent that the structural support system provided in the original design was insufficient. The calculations provided showed that the support system would fail upon one relief valve opening, much less four opening at the same time. The analysis from Tyco/Anderson Greenwood and Crosby uncovered some inconsistencies in the maintenance of the relief valves but none that would have caused the relief valves to relieve outside of anticipated and advertised ranges.

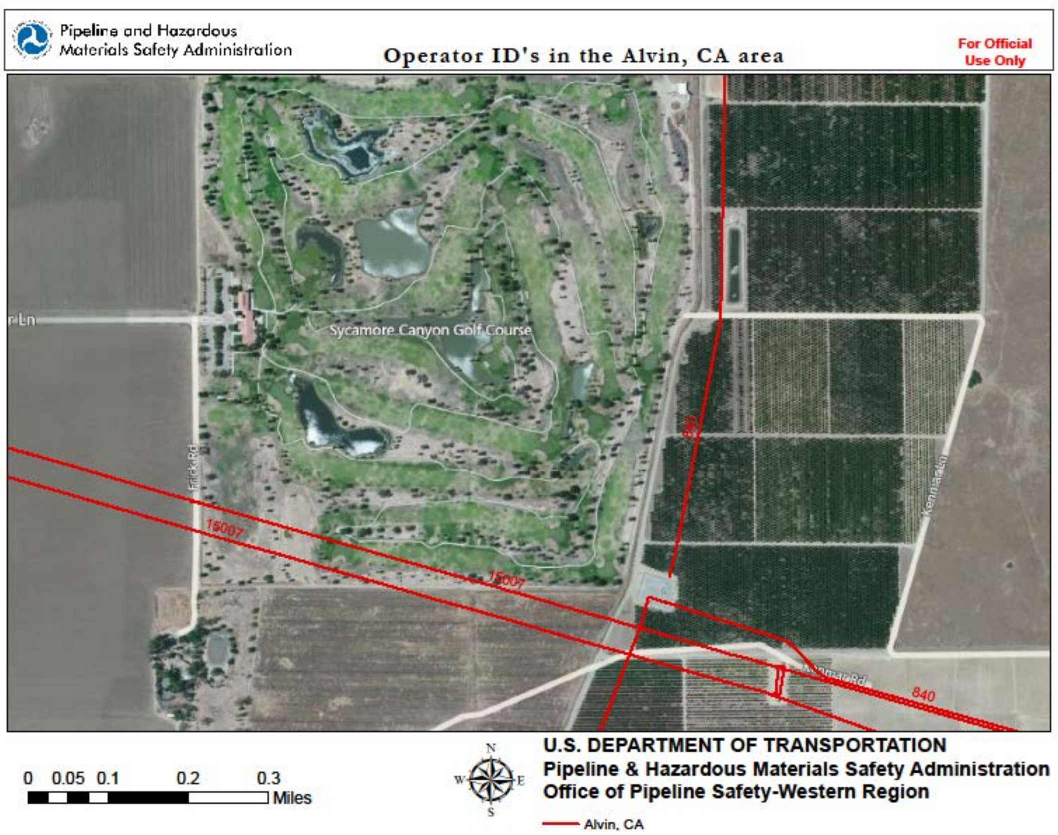
Appendices

1. Maps and Photographs
2. NRC Report
3. Operator Incident Report to PHMSA
4. Mojave Root Cause Report
5. Mojave Root Cause Revised Report
6. SES Failure Analysis Report
7. SES Stress/Flow Analysis Report
8. Tyco/Anderson Greenwood Relief Valve Testing Report

Mojave Pipeline Relief Event 2 MAY 2012



Overview of the Mojave Pipeline. The green dashed line is where Kern River Pipeline delivers natural gas into the Mojave Pipeline System.



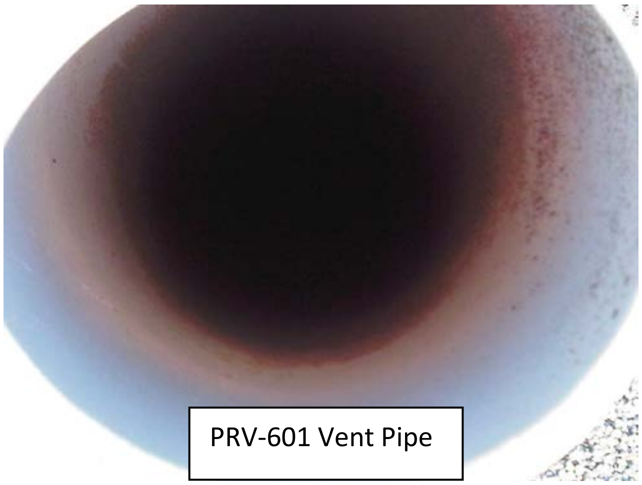
Close Up Aerial View of Bifurcation Point.

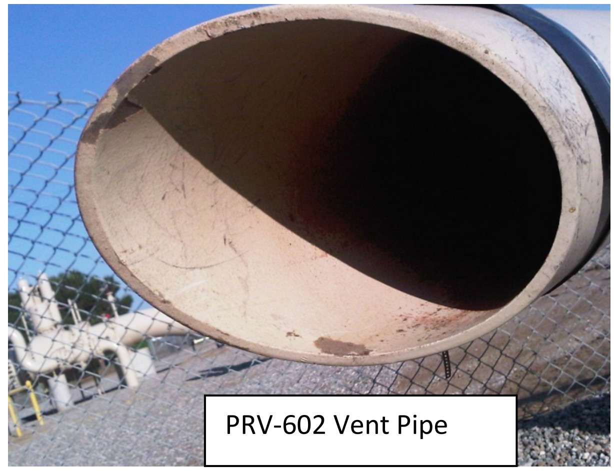
Failure of RV Support System. I-Beam is 90 degree from proper for maximum support. No 45 degree braces to counter moment applied by relief force.

180 degree picture from prior picture.

Two (2) Relief vents thrown clear after failure of relief support system.

30” RV Header Pipe being removed. Tee outlets are 8” swedged down to 6”.





Four (4) Vent Stacks showing only PRV-603 possibly relieved. Operator stated that none of these relief devices have ever actuated prior to 5/2/12. Installation was circa 1991/1992.

NATIONAL RESPONSE CENTER 1-800-424-8802
*** For Public Use ***
Information released to a third party shall comply with any applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1010322

INCIDENT DESCRIPTION

*Report taken at 12:28 on 02-MAY-12
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
The incident occurred on 02-MAY-12 at 08:30 local time.
Affected Medium: SUBSURFACE

SUSPECTED RESPONSIBLE PARTY

Organization: EL PASO NATURAL GAS
TUCSON, AZ 85711

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

SEE LAT AND LONG County: KERN
State: CA
Latitude: 35° 16' 16" N
Longitude: 118° 08' 06" W
NONE

RELEASED MATERIAL(S)

CHRIS Code: ONG Official Material Name: NATURAL GAS
Also Known As:
Qty Released: 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

CALLER STATED THAT THERE WAS A RELEASE OF AN UNKNOWN AMOUNT OF NATURAL GAS FROM A 30 INCH PIPE LINE, THE CAUSE IS UNKNOWN.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

DAMAGES

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES:	NO	Hospitalized:	Empl/Crew:	Passenger:
FATALITIES:	NO	Empl/Crew:	Passenger:	Occupant:
EVACUATIONS:	NO	Who Evacuated:	Radius/Area:	
Damages:	NO			

Closure Type		Description of Closure	Length of Closure	Direction of Closure	
Air:	N				
Road:	N				Major Artery: N
Waterway:	N				
Track:	N				

Passengers Transferred: NO

Environmental Impact: UNKNOWN

Media Interest: NONE Community Impact due to Material:

REMEDIAL ACTIONS

INVESTIGATION UNDERWAY
Release Secured: NO
Release Rate:
Estimated Release Duration: 40 MINUTE

WEATHER

Weather: CLEAR, °F

ADDITIONAL AGENCIES NOTIFIED

Federal: NONE
State/Local: NONE
State/Local On Scene: NONE
State Agency Number: NONE

NOTIFICATIONS BY NRC

CA U.S. ATTORNEY'S OFFICE NORTH (MAIN OFFICE)
02-MAY-12 12:33
USCG ICC (ICC ONI)
02-MAY-12 12:33
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
02-MAY-12 12:33
U.S. EPA IX (MAIN OFFICE)
02-MAY-12 12:34
FEMA REGION 09 (SITUATION AWARENESS UNIT)
02-MAY-12 12:33
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
02-MAY-12 12:33
NOAA RPTS FOR CA (MAIN OFFICE)
02-MAY-12 12:33
CA STATE EMERGENCY SERVICES (MAIN OFFICE)
02-MAY-12 12:33
STATE TERRORISM & THREAT ASSESS CTR (COMMAND CENTER SACRAMENTO)
02-MAY-12 12:33
CITY OF YUMA EMERGENCY MANAGEMENT (COMMAND CENTER)
02-MAY-12 12:33

ADDITIONAL INFORMATION

CALLER WILL MAKE NOTIFICATIONS

*** END INCIDENT REPORT # 1010322 ***

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed 100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.	OMB NO: 2137-0522 EXPIRATION DATE: 01/31/2014

U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Report Date:**	06/01/2012
	No.	20120058 - 15649 (DOT Use Only)

INCIDENT REPORT - GAS TRANSMISSION AND GATHERING PIPELINE SYSTEMS

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 PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	**Yes**

Last Revision Date:	11/07/2012
1. Operator's OPS-issued Operator Identification Number (OPID):	4280
2. Name of Operator	EL PASO NATURAL GAS CO
3. Address of Operator:	
3a. Street Address	1001 Louisiana Street
3b. City	Houston
3c. State	Texas
3d. Zip Code:	77002-5089
4. Local time *(24-hr clock)* and date of the Incident:	05/02/2012 08:20
5. Location of Incident:	
Latitude:	35.161604
Longitude:	-118.806282
6. National Response Center Report Number (if applicable):	1010322
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	05/02/2012 09:28
8. Incident resulted from:	Unintentional release of gas
9. Gas released: (select only one, based on predominant volume released)	Natural Gas
- Other Gas Released Name:	
10. Estimated volume of commodity released unintentionally - Thousand Cubic Feet (MCF):	585,457.00
11. Estimated volume of intentional and controlled release/blowdown - Thousand Cubic Feet (MCF)	
12. Estimated volume of accompanying liquid release (Barrels):	
13. Were there fatalities?	No
- If Yes, specify the number in each category:	
13a. Operator employees	
13b. Contractor employees working for the Operator	
13c. Non-Operator emergency responders	
13d. Workers working on the right-of-way, but NOT associated with this Operator	
13e. General public	
13f. Total fatalities (sum of above)	
14. Were there injuries requiring inpatient hospitalization?	No
- If Yes, specify the number in each category:	
14a. Operator employees	
14b. Contractor employees working for the Operator	
14c. Non-Operator emergency responders	
14d. Workers working on the right-of-way, but NOT associated with this Operator	
14e. General public	
14f. Total injuries (sum of above)	
15. Was the pipeline/facility shut down due to the incident?	Yes

- If No, Explain:	
- If Yes, complete Questions 15a and 15b: *(use local time, 24-hr clock)*	
15a. Local time and date of shutdown	05/02/2012 09:06
15b. Local time pipeline/facility restarted	05/04/2012 19:00
- Still shut down? (* Supplemental Report Required)	
16. Did the gas ignite?	No
17. Did the gas explode?	No
18. Number of general public evacuated:	0
19. Time sequence *(use local time, 24-hour clock)*:	
19a. Local time operator identified Incident	05/02/2012 08:30
19b. Local time operator resources arrived on site	05/02/2012 08:30

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Incident onshore?	Yes
- Yes (Complete Questions 2-12)	
- No (Complete Questions 13-15)	
If Onshore:	
2. State:	California
3. Zip Code:	93203
4. City	Arvin
5. County or Parish	Kern
6. Operator designated location	Milepost/Valve Station
Specify:	118+1904
7. Pipeline/Facility name:	Line 1901 Common, Mojave Pipeline
8. Segment name/ID:	Line 1901 Bifurcation
9. Was Incident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Incident :	Operator-controlled property
11. Area of Incident (as found) :	Aboveground
Specify:	Typical aboveground facility piping or appurtenance
Other – Describe:	
Depth-of-Cover (in):	
12. Did Incident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
Name of body of water (If commonly known):	
Approx. water depth (ft) at the point of the Incident:	
Select:	
If Offshore:	
13. Approx. water depth (ft) at the point of the Incident:	
14. Origin of Incident:	
- If "In State waters":	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- If "On the Outer Continental Shelf (OCS)":	
- Area:	
- Block #:	
15. Area of Incident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility: - Interstate - Intrastate	Interstate
2. Part of system involved in Incident:	Onshore Pipeline, Including Valve Sites
3. Item involved in Incident:	Pipe
- If Pipe – Specify:	Pipe Body
3a. Nominal diameter of pipe (in):	6
3b. Wall thickness (in):	.28
3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	35,000

3d. Pipe specification:	API 5L-B
3e. Pipe Seam – Specify:	Seamless
- If Other, Describe:	
3f. Pipe manufacturer:	NKK Corporation
3g. Year of manufacture:	1991
3h. Pipeline coating type at point of Incident – Specify:	Paint
- If Other, Describe:	
- If Weld, including heat-affected zone – Specify:	
- If Other, Describe:	
- If Valve – Specify:	
- If Mainline – Specify:	
- If Other, Describe:	
3i. Mainline valve manufacturer:	
3j. Year of manufacture:	
- If Other, Describe:	
4. Year item involved in Incident was installed:	1992
5. Material involved in Incident:	Carbon Steel
- If Material other than Steel or Plastic – Specify:	
6. Type of Incident involved:	Rupture
- If Mechanical Puncture – Specify Approx. size:	
Approx. size: in. (in axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other – Describe:	
- If Rupture - Select Orientation:	Circumferential
- If Other – Describe:	
Approx. size: in. (widest opening):	6
by in. (length circumferentially or axially):	6
- If Other – Describe:	

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Class Location of Incident:	Class 1 Location
2. Did this Incident occur in a High Consequence Area (HCA)?	No
- If Yes:	
2a. Specify the Method used to identify the HCA:	
3. What is the PIR (Potential Impact Radius) for the location of this Incident? Feet:	158
4. Were any structures outside the PIR impacted or otherwise damaged due to heat/fire resulting from the Incident?	No
5. Were any structures outside the PIR impacted or otherwise damaged NOT by heat/fire resulting from the Incident?	No
6. Were any of the fatalities or injuries reported for persons located outside the PIR?	No
7. Estimated Property Damage :	
7a. Estimated cost of public and non-Operator private property damage	$ 16,000
7b. Estimated cost of Operator's property damage & repairs	$ 488,000
7c. Estimated cost of Operator's emergency response	$ 8,000
7d. Estimated other costs	$ 0
Describe:	
7e. Total estimated property damage (sum of above)	$ 512,000
Cost of Gas Released	
7f. Estimated cost of gas released unintentionally	$ 963,643
7g. Estimated cost of gas released during intentional and controlled blowdown	$ 0
7h. Total estimated cost of gas released (sum of 7.f & 7.g above)	$ 963,643

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Incident (psig):_	917.00
2. Maximum Allowable Operating Pressure (MAOP) at the point and time of the Incident (psig):	1,200.00
3. Describe the pressure on the system or facility relating to the Incident:	Pressure did not exceed MAOP

4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Incident operating under an established pressure restriction with pressure limits below those normally allowed by the MAOP?	No
- If Yes - (*Complete 4a and 4b below)*	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. - 5f. below):*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	100,320
5d. Is the pipeline configured to accommodate internal inspection tools?	No
- If No – Which physical features limit tool accommodation? *(select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other	Yes
- If Other, Describe:	Piping involved was fabricated station type of a facility such that an ILI does not apply.
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	Yes
- If Yes, which operational factors complicate execution? *(select all that apply)*	
- Excessive debris or scale, wax, or other wall build-up	
- Low operating pressure(s)	
- Low flow or absence of flow	
- Incompatible commodity	
- Other	Yes
- If Other, Describe:	See Question 5(d) above.
5f. Function of pipeline system:	Transmission System
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Incident?	Yes
- If Yes:	
6a. Was it operating at the time of the Incident?	Yes
6b. Was it fully functional at the time of the Incident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations) assist with the detection of the Incident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Incident?	No
7. How was the Incident initially identified for the Operator?	SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume or pack calculations)
- If Other – Describe:	
7a. If "Controller", "Local Operating Personnel, including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 7, specify the following:	
8. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Incident?	No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: (provide an explanation for why the Operator did not investigate)
- If No, the operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	Operational parameters were within normal limits and no remote valve commands had been issued.
- If Yes, Describe investigation result(s) *(select all that apply)*:	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the operator), and other factors associated with fatigue	

- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator) and other factors associated with fatigue	
- Provide an explanation for why not:	
- Investigation identified no control room issues	
- Investigation identified no controller issues	
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above –	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Incident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
1a. Describe how many were tested:	
1b. Describe how many failed:	
2. As a result of this Incident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Describe how many were tested:	
2b. Describe how many failed:	

PART G - APPARENT CAUSE

Select only one box from PART G in the shaded column on the left representing the APPARENT Cause of the Incident, and answer the questions on the right. Describe secondary, contributing, or root causes of the Incident in the narrative (PART H).

Apparent Cause:	G6 - Equipment Failure

G1 - Corrosion Failure - *only one **sub-cause** can be picked from shaded left-hand column*

Corrosion Failure – Sub-cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other	
- If Other – Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other	
- If Other – Describe:	
4. Was the failed item buried under the ground?	
- If Yes:	
4a. Was failed item considered to be under cathodic protection at the time of the incident?	
- If Yes, Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the incident?	
4c. Has one or more Cathodic Protection Survey been conducted	

at the point of the incident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- If Other, Describe:	
7. Cause of corrosion *(select all that apply)*:	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*:	
- Field examination	
- Determined by metallurgical analysis	
- Other	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*:	
- Low point in pipe	
- Elbow	
- Drop-out	
- Other	
- If Other, Describe:	
10. Was the gas/fluid treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
14. Has one or more internal inspection tool collected data at the point of the Incident?	
14a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage Tool	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
If Other, Describe:	
15. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes,	
Most recent year tested:	
Test pressure (psig):	
16. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	

Most recent year conducted:	
17. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
17a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year examined:	
- Guided Wave Ultrasonic	
Most recent year examined:	
- Handheld Ultrasonic Tool	
Most recent year examined:	
- Wet Magnetic Particle Test	
Most recent year examined:	
- Dry Magnetic Particle Test	
Most recent year examined:	
- Other	
Most recent year examined:	
If Other, Describe:	
G2 - Natural Force Damage - *only one **sub-cause** can be picked from shaded left-handed column*	
Natural Force Damage – Sub-Cause:	
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	
- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	
- If Other, Describe:	
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If High Winds:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Incident generated in conjunction with an extreme weather event?	
6a. If yes, specify: *(select all that apply)*:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage *only one **sub-cause** can be picked from shaded left-hand column*	
Excavation Damage – Sub-Cause:	
- If Excavation Damage by Operator (First Party):	
- If Excavation Damage by Operator's Contractor (Second Party):	
- If Excavation Damage by Third Party:	
- If Previous Damage Due to Excavation Activity:	
Complete Questions 1-5 ONLY IF the "Item Involved in Incident" (From Part C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Incident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Year:	
- Ultrasonic	
Year:	
- Geometry	
Year:	

- Caliper	
Year:	
- Crack	
Year:	
- Hard Spot	
Year:	
- Combination Tool	
Year:	
- Transverse Field/Triaxial	
Year:	
- Other:	
Year:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
5a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Year:	
- Guided Wave Ultrasonic	
Year:	
- Handheld Ultrasonic Tool	
Year:	
- Wet Magnetic Particle Test	
Year:	
- Dry Magnetic Particle Test	
Year:	
- Other	
Year:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from *(select all that apply)*:	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred *(select all that apply)*:	
- Public	
- If Public, Specify:	
- Private	
- If Private, Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator :	
10. Type of excavation equipment :	
11. Type of work performed :	

12. Was the One-Call Center notified? - Yes - No	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption: (hours)	
17. Description of the **CGA-DIRT Root Cause** (*select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, then one predominant second level CGA-DIRT Root Cause as well*):	
- Predominant first level CGA-DIRT Root Cause:	
- If One-Call Notification Practices Not Sufficient, Specify:	
- If Locating Practices Not Sufficient, Specify:	
- If Excavation Practices Not Sufficient, Specify:	
- If Other/None of the Above, Explain:	

G4 - Other Outside Force Damage - only one **sub-cause** can be selected from the shaded left-hand column

Other Outside Force Damage – Sub-Cause:	
- If Nearby Industrial, Man-made, or Other Fire/Explosion as Primary Cause of Incident:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Routine or Normal Fishing or Other Maritime Activity NOT Engaged in Excavation:	
- If Electrical Arcing from Other Equipment or Facility:	
- If Previous Mechanical Damage NOT Related to Excavation:	
Complete Questions 3-7 ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is Pipe or Weld.	
3. Has one or more internal inspection tool collected data at the point of the Incident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other:	
Most recent year run:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted	

since original construction at the point of the Incident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident :	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Incident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
If **- If Intentional Damage:**	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	

G5 – Material Failure of Pipe or Weld	**Use this section to report material failures ONLY IF the "Item Involved in Incident" (from PART C, Question 3) is "Pipe" or "Weld."**
	*Only one **sub-cause** can be selected from the shaded left-hand column
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-case selected below is based on the following *(select all that apply)*:	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe	
- Sub-cause is Tentative or Suspected; Still Under Investigation *(Supplemental Report required)*	
- If Construction-, Installation- or Fabrication- related:	
2. List contributing factors: *(select all that apply)*	
- If Fatigue or Vibration related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress	
- Other	
- If Other, Describe:	
- If Original Manufacturing-related (NOT girth weld or other welds formed in the field):	
2. List contributing factors: *(select all that apply)*	
- If Fatigue or Vibration related:	
Specify:	
- If Other, Describe:	
- Mechanical Stress	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- If Other, Describe:	

Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional Factors (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Incident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Incident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Incident:	
Most recent year conducted:	
- If Yes, but the point of the Incident was not identified as a dig site:	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Incident since January 1,2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	

Describe:	
G6 - Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	Other Equipment Failure
- If Malfunction of Control/Relief Equipment:	
1. Specify:	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- Pressure Regulator	
- ESD System Failure	
- Other	
- If Other, Describe:	
- If Compressor or Compressor-related Equipment:	
2. Specify:	
- If Other, Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other, Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other, Describe:	
- If Defective or Loose Tubing or Fitting:	
- If Failure of Equipment Body (except Compressor), Vessel Plate, or other Material:	
- If Other Equipment Failure:	
5. Describe:	Undersized structural support members did not withstand veting forces.
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	Yes
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported gas/fluid	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 – Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
- If Damage by Operator or Operator's Contractor NOT Related to Excavation and NOT due to Motorized Vehicle/Equipment Damage:	
- If Underground Gas Storage, Pressure Vessel, or Cavern Allowed or Caused to Overpressure:	

1. Specify:	
- If Other, Describe:	
- If Valve Left or Placed in Wrong Position, but NOT Resulting in an Overpressure:	
- If Pipeline or Equipment Overpressured:	
- If Equipment Not Installed Properly:	
- If Wrong Equipment Specified or Installed:	
- If Other Incorrect Operation:	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Incident related to: *(select all that apply)*	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Incident:	
5. Was the task(s) that led to the Incident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Incident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Incident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART - H NARRATIVE DESCRIPTION OF THE INCIDENT

El Paso Natural Gas (EPNG) Company Gas Control personal encountered a pressure drop via SCADA information on the Mojave Pipeline, which EPNG operates. Local operating personnel in the vicinity of Arvin, CA, were dispatched and found that a fabrication of relief valves and pipe supports had failed, causing damage to the Mojave facility and some surrounding cherry trees. The investigation into the root cause of revealed the following:
The inadequacy of the structural support provided at this installation and its failure allowed for the failure of the piping systems it was intended to protect.
- Undersized structural members in support to withstand predicted forces of venting
- Incorrect orientation of support columns and cross member (weak axis exposed)
- Connection between pipe and support didn¿t insure transfer of forces

The relief valves were found not to have heightened the likelihood of the gas release nor did they add to the impact of the release, so they were not contributing factors as defined by PHMSA.

File Full Name

PART I - PREPARER AND AUTHORIZED SIGNATURE

Preparer's Name	Kenneth C Peters
Preparer's Title	Engineer - Pipeline EP
Preparer's Telephone Number	2053257554
Preparer's E-mail Address	ken_peters@kindermorgan.com
Preparer's Facsimile Number	2053253729
Authorized Signature's Name	Keneth C Peters
Authorized Signature Title	Engineer - Pipeline EP
Authorized Signature Telephone Number	2053257554
Authorized Signature Email	ken_peters@kindermorgan.com
Date	11/07/2012

Appendix 4-8

These documents are on file at PHMSA