(3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; and

(4) Information about how a failure would affect the high consequence area, such as location of the water intake.

Page 3 of the KMEP MidCon System risk model data tabulation lists 50 pipeline segments. KM used over twenty of the available category columns to populate segment information (eg. diameter, wall thickness, seam design, depth of cover, etc.). Seventy-Five percent (75%) of the applied columns cells are populated with "assumed" or "unknown". Applying "assumed" or "unknown" to a data entry rightfully assigns a higher risk for subsequent risk analysis. However, the application of "assumed" or "unknown" is excessive, indicating either inadequate data collection or data tabulation. As a result, the risk model would be limited in its ability to differentiate output. For example in the listed 50 pipeline segments, certain basic data categories are filled entirely with "assumed" or "unknown".

- Seam Design.
- Block Valve Rating.
- Maximum expected discharge pressure.
- Internal Corrosion Inhibitor.

6. § 195.452(e)(1)(iv) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?

(1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:

(iv) Product transported.

In its BAP, KM had removed eleven pipeline sections from the schedule because it had classified them as idle lines (no product). While KM believed that some of these lines had been evacuated of hazardous materials, KM had classified others as idle lines without having checked that hazardous materials had been removed. KM personnel told the inspection team that these sections did not appear on the BAP because KM intended to remove hazardous materials from them. Segment identification had been done for these lines to ease any potential return to service.

For the lines to be excluded from the BAP, they must have had all hazardous materials confirmed and documented as removed. Those eleven lines segments are:

BAP Rank	System	Segment Name	Length (mi)	% in HCA	In top BAP 50% ?
7	KMLT	GX146-Mobil 36"	1.9	100	Yes
9	KMLT	GX146 36"	2.2	100	Yes
13	KMLT	GX100 14"	1.4	100	Yes
17	KMLT	GX110 6"	5.6	100	Yes
19	KMLT	GX170 6"	4.6	100	Yes
91	CalNev	3" Roadway Lateral	0.2	100	Yes
94	SFPP	LS-79-2 Portland Chevron 8"	1.0	100	Yes
99	SFPP	TX/AZ Tucson Term-2	6.0	19	Yes
138	SFPP	LS-9 Bradshaw Rocklin 10" NIS	16.2	100	No
179	CFPL	Orlando Airport 6"	2.3	100	No
193	MidCon	PL-305 Lemont Citgo NIS	1.5	83	No

7. **§ 195.452(d)(3)(ii) When must operators complete baseline assessments? Operators must complete baseline assessments as follows:**

(3) Newly-identified areas.

(ii) An operator must incorporate a new unusually sensitive area into its baseline assessment plan within one year from the date the area is identified. An operator must complete the baseline assessment of any line pipe that could affect the newly-identified high consequence area within five years from the date the area is identified.

Local field knowledge has been collected, but more than one year has past without the information being applied to the HCA changes. Records show that KM had interviewed over 40 field personnel from 03-12-02 to 03-21-02, but as of April 2003, the results of all these interviews were not used to help identify new HCAs or update information about existing HCAs. Appendix A of the RiskCat Documentation shows that local field interview input is not included in the data sources used to generate HCA lists.

8. § 195.452(c)(2) What must be in the baseline assessment plan?

(2) An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.

KM had made changes to its BAP from 03-31-02, to the current BAP of 03-15-03, and noted those changes on the program change log sheets, but had not adequately documented the technical basis, timing, justification and results impact.

9. § 195.452(h)(2) What actions must an operator take to address integrity issues?

(2) Discovery of condition. Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must promptly, but no later than 180 days after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the 180-day period is impracticable.

KM's specifications for Inline inspection Vendor preliminary report parameters do not include a requirements to report specific features. KM informed the inspection team that a greater than 70% wall loss is usually identified in the vendor's preliminary report, that KM's existing requirements for inline inspection final report time-line satisfies IM rule requirements, and that preliminary reports are considered as "extra" information. Because many current generation inline inspection vendors and related tools have the capability to generate information on a preliminary basis, KM should be cautious in waiting for the final assessment reports to respond to anomalous indications from these tools, which may indicate a potentially imminent integrity threat.

10. **§ 195.452(f)(8) What are the elements of an integrity management program? An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:**

    (8) A process for review of integrity assessment results and information analysis by a person qualified to evaluate the results and information (see paragraph (h)(2) of this section).

    KM does not include any consideration for inline inspection tool tolerances when analyzing inline inspection data.

11. **§ 195.452(f)(4) An operator must include, at minimum, each of the following elements in its written integrity management program:**

    (4) Criteria for remedial actions to address integrity issues raised by the assessment methods and information analysis (see paragraph (h) of this section);

    KM's integrity program lacks criteria for comparing vendor and field definitions of anomaly categories to IM rule definitions (eg., "ovalities," flat spots"). It is unclear, by the lack of program definitions, what constitutes the criteria and thresholds for reportable features. Any anomaly that is described by the inline inspection vendor using terminology not explicitly used in the rule (e.g., "ovalities," "flat spots") is treated by KM as not subject to the remediation requirements of 452(h).

Under 49 United States Code, §60122, you are subject to a civil penalty not to exceed $100,000 for each violation for each day the violation persists up to a maximum of $1,000,000 for any related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations labeled 1, 2a, 2b, 2c, 2d, 3b, 4, 5, and 6. It is recommended that you be preliminarily assessed a civil penalty for these labeled Items of $325,000 as follows:

Item	Code Reference	Description	Proposed Civil Penalty
1	§195.452(b)(3)	Exclusion of LF/ERW & potential SCC	$100,000
2a	§195.452(e)(1)(i)	Exclusion of previous assessment data	$25,000

2b	§195.452(e)(1)(iii)	Exclusion of repair history	$25,000
2c	§195.452(e)(1)(vii)	Exclusion of environmental factors	$25,000
2d	§195.452(e)(1)(ix)	Exclusion of physical support factor	$25,000
3b	§195.452(i)(2)	Excessive weighting for product type	$50,000
4	§195.452(f)(3)	Differentiating age during analysis	$15,000
5	§195.452(g)	Insufficient data for information analysis	$50,000
6	§195.452(e)(1)(iv)	Excluding potentially filled line segments, as idle	$10,000

Regarding Items 1, 2a, 2b, 2c, 2d, 3a, 3b, 3c, 3d, 4, 5, 6 and 7 pursuant to 49 United States Code §60118, the OPS proposes to issue KM, a Compliance Order in the form of the Proposed Compliance Order that is attached to and made a part of this Notice of Probable Violation.

The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations labeled 3a, 3c, 3d, and 7, and recommends that you not be preliminarily assessed a civil penalty.

As for labeled items 8, 9, 10, and 11, the Compliance Officer recommends that you not be preliminarily assessed a civil penalty or a compliance order. However, should you not correct the circumstances leading to the violation, we will take enforcement action when and if the continued violation comes to our attention.

Also attached to and made a part of this Notice of Probable Violation is an enclosed description of the courses of action available to you in responding to this Notice. Please note that if you elect to make a response, you must do so within thirty (30) days of receipt of this Notice, or waive your rights under 49 CFR §190.209. No response or a response that does not contest the allegations in the Notice authorizes the Director, OPS to find the facts to be as alleged herein and to issue appropriate orders. The thirty (30) day response period may be extended for good cause shown if the request for extension is submitted within the original thirty (30) day period.

Please submit all written correspondence to:

Mr. William H. Gute
Director, Eastern Region
DOT/RSPA/Office of Pipeline Safety
409 3rd St., SW, Suite 300/DPS-24
Washington, DC 20024

Please refer to **CPF No. 1-2004-5004** in any correspondence or communication on this matter.

Sincerely,

William H. Gute
Director, Eastern Region
Office of Pipeline Safety

Enclosures

BCOY/sj/DPS-24/(609) 989-2180/7/15/04
FILE: CPF-1-2004-5004/Kinder Morgan
g:\wpfiles\Byron\cpfltrs\cpf120045004.bc.wpd
cc: DPS-22.1, DPS-24, NJDO, Regions

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code, §60118, the OPS proposes to issue to KM, a Compliance Order incorporating the following requirements to assure the compliance of KM with the pipeline safety regulations applicable to its operations.

The proposed items all relate to the need for KM to improve its Integrity Management Program. The OPS recognizes that a number of program elements are still in the development stage, and that documentation will continue to evolve as methods are fully developed and defined. However, management and analytical process guidance used to implement the program must be of sufficient detail and specificity to clearly articulate the necessary steps to perform each program element and ensure repeatability, describe the key input information sources, define the process output products, their documentation (including the justification for decisions), and document retention requirements and specify organizational responsibilities for performing key process steps.

1. With respect to Item 1 of the Notice, KM must:

   Either provide a specific and thorough technical basis for exclusion, or incorporate provisions in the risk model and other associated aspects of the Integrity Management program to address and account for pre-70 low frequency ERW piping and the potential for SCC.

2. With respect to Item 2 of the Notice, KM must revise the risk factors in the Integrity Management program to include data from:

   (a) Results of previous integrity assessments, including previously identified defect type and predicted defect growth rate.

   (b) Repair history.

   (c) Local environmental factors such as soil corrosivity, subsidence, climatic conditions, and geo-technical hazards.

   (d) Physical support of a segment such as a cable suspension bridge.

3. With respect to Item 3 of the Notice, KM must:

   (a) Provide adequate justification and documentation in general for the basis of risk factor weighting and scores.

(b) Either provide specific justification for the heavy weighting of product type in the risk rankings, or adjust the weighting to be more in line with KM's actual operating history.

(c) Revise and substantiate the assignment of weighting factors for HCA type.

(d) Either justify the weighted averaging of risk scores towards shorter lines, or revise the weighted averaging process for equitable treatment for all line segment lengths.

4. With respect to Item 4 of the Notice, KM must:

Revise the risk model scoring to differentiate the age of previous inline inspections and hydrostatic pressure tests.

5. With respect to Item 5 of the Notice, KM must:

Either substantiate and justify the exclusion of pipeline integrity data, or incorporate all appropriate available pipeline integrity data even though similar data may not be uniformly available for all line segments.

6. With respect to Item 6 of the Notice, KM must:

Conduct a thorough review of records and physical examination, as deemed appropriate, of the eleven sections of lines that had been removed from the BAP schedule due to being classified as idle lines. As a result of that review and examination, either drain and evacuate those lines found to still contain hazardous material, or revise the status of any line still retaining hazardous material in the risk model and other associated aspects of the Integrity Management Program.

7. With respect to Item 7 of the Notice, KM must:

Incorporate field information to identify new HCAs, update existing HCA information, and update the BAP and Information Analysis to reflect the updated HCA information.

8. Items 1-7 above must be completed within 180 days of receipt of a Final Order.

9. Documentation collected or generated to demonstrate the completion of each item above must include reference numbers to the items above.

10. Ten copies of all documentation to demonstrate the completion of each item above must be sent to the Regional Director, OPS/ER.

Mr. Robert E. Hogfoss, Esq.
Hunton & Williams LLP
Bank of America Plaza, Suite 400
600 Peachtree Street, N.E.
Atlanta, GA 30308-2216

Re: CPF Nos. 1-2004-5004 and 1-2004-5005M

Dear Mr. Hogfoss:

Pursuant to your request dated August 16, 2004, and in accordance with 49 C.F.R. § 190.211, an informal hearing will be held regarding the Notice of Probable Violation, Proposed Civil Penalty, Proposed Compliance Order, and Notice of Amendment dated July 15, 2004 issued to Kinder Morgan Energy Partners, L.P. by the Office of Pipeline Safety. As you know, the hearing is scheduled to begin on Tuesday, April 12, 2005. The hearing will commence at 9:30 a.m. EST and will be held at the Office of Pipeline Safety, Eastern Region, 409 3rd Street, SW, Suite 300, Washington, DC 20024.

Upon arrival at the building, representatives of Kinder Morgan will be required to present photo identification to the security personnel. Please inform the security personnel that you are there to see William Gute, Office of Pipeline Safety. The security personnel may phone the Office of Pipeline Safety to request that a staff member escort you to the assigned conference room.

I will serve as Presiding Official at the hearing. If you have any questions, please do not hesitate to contact me at (202) 366-4400.

Sincerely,

Larry White
Presiding Official

cc: William Gute, Director, Eastern Region, OPS

VIA CERTIFIED MAIL AND FACSIMILE TO (404) 888-4190

From: Schwarzkopf, Michael (PHMSA)
To: Nguyen, Huy (PHMSA)
Subject: RE: Kinder Morgan Liquids Pipeline II & CRM Coordination
Date: Thursday, April 24, 2014 7:36:02 AM

Thanks Huy

-----Original Message-----
From: Nguyen, Huy (PHMSA)
Sent: Thursday, April 24, 2014 9:33 AM
To: Schwarzkopf, Michael (PHMSA)
Cc: Larson, Terrence (PHMSA)
Subject: RE: Kinder Morgan Liquids Pipeline II & CRM Coordination

Mike,

The Western Region have not inspected the Houston Control Room. However, the Western Region did conduct a Control Room Management Inspection in 2012 for the Pacific Operations Region in Orange County, CA. The Pacific Operations Region includes the CALNEV and SFPP systems in Arizona, California, Nevada, New Mexico, Oregon, and western Texas. It's my understanding that the Western Region is not planning to inspect the Houston Control Room.

Thanks.

Huy

From: Schwarzkopf, Michael (PHMSA)
Sent: Thursday, April 24, 2014 6:11 AM
To: Binns, Terri J. (PHMSA); Nguyen, Huy (PHMSA); Larson, Terrence (PHMSA)
Cc: Khayata, Michael (PHMSA); Taylor, Chris (PHMSA); Urisko, James (PHMSA); Hindman, Gregory C. (PHMSA)
Subject: Kinder Morgan Liquids Pipeline II & CRM Coordination

Terri, Huy, and Terry

The Southern Region is conducting an II on three (3) Kinder Morgan liquid inspection systems (Central Florida, Parkway, & Plantation) this year and a question has come up from the Lead Engineer on how to handle the control room for two of the pipelines (Central Florida & Parkway.)

Central Florida & Parkway are operated by Kinder Morgan's liquid control room in Houston - Central Florida's CRM operation was transferred for Plantation's Control Room in Alpharetta, GA, and Parkway was placed under the Houston Control Room when it was placed in service recently.

I can't find a record of a CRM done on the Houston Control Room under SFPP or on the Control Room spreadsheet in SharePoint.

I was wondering if either of your Regions have inspected (or plans to inspect) the Houston Control Room ?

The inspection team is considering a check of the transfer of the Central Florida control room

to Houston, and the MOC and Point-to-Point checks for Parkway. Whether or not the Control Room has been inspected brings in some questions as the combined mileage for the two pipelines is about 350 miles while SFPP alone has over 2,800 miles in your Regions and we're not familiar with SFPP.

If you're conducting a CRM, the CFPL & Parkway teams could join in and assist with your CRM inspection, or they can limit checks to items that do not interfere. One of the engineers who inspected Plantation's CRM & Control Room in Georgia is on the inspection and PPL is under SFPP for the CRM

Thank you

Safety Program Relationship (SPR) Detail

Operator ID: 18092

IM

OME

CRM

PA

DP

OQ

OPA

D&A

Entry Date

Entry Date

Entry Date

Entry Date

Entry Date

Entry Date

Entry Date

Entry Date

OPID

Submitting Oper Name

Status

Primary OpID

SPR Name

2190

CENTRAL FLORIDA PIPELINE CORP

Current

18092

KINDER MORGAN

04/21/1995

04/21/1995

04/21/1995

04/21/1995

04/21/1995

04/21/1995

04/21/1995

04/21/1995

2564

COLORADO INTERSTATE GAS CO

Current

18092

KINDER MORGAN

02/07/2013

02/07/2013

02/07/2013

4472

CYPRESS INTERSTATE PIPELINE LLC

Current

18092

KINDER MORGAN

04/20/1995

04/20/1995

04/20/1995

04/20/1995

04/20/1995

04/20/1995

04/20/1995

04/20/1995

15674

PLANTATION PIPE LINE CO

Current

18092

KINDER MORGAN

06/04/1987

06/04/1987

06/04/1987

06/04/1987

06/04/1987

06/04/1987

06/04/1987

06/04/1987

18092

SFPP, LP

Current

18092

KINDER MORGAN

06/07/1989

06/07/1989

06/07/1989

06/07/1989

06/07/1989

06/07/1989

06/07/1989

06/07/1989

26125

CALNEV PIPELINE CO

Current

18092

KINDER MORGAN

06/04/1987

06/04/1987

06/04/1987

06/04/1987

06/04/1987

06/04/1987

06/04/1987

06/04/1987

31555

KINDER MORGAN CO2 CO. LP

Current

18092

KINDER MORGAN

01/14/2013

01/14/2013

01/14/2013

01/14/2013

01/14/2013

01/14/2013

31957

KINDER MORGAN WINK PIPELINE LP

Current

18092

KINDER MORGAN

01/14/2013

01/14/2013

01/14/2013

01/14/2013

01/14/2013

01/14/2013

32114

COPANO NGL SERVICES LLC

Current

18092

KINDER MORGAN

01/01/2014

01/01/2014

05/01/2013

32258

KINDER MORGAN COCHIN LLC

Current

18092

KINDER MORGAN

08/17/2007

08/17/2007

08/17/2007

08/17/2007

08/17/2007

08/17/2007

08/17/2007

08/17/2007

32541

COPANO NGL SERVICES (MARKHAM), LLC

Current

18092

KINDER MORGAN

01/01/2014

01/01/2014

05/01/2013

32542

LEGADO PERMIAN, LLC

Current

18092

KINDER MORGAN

06/03/2013

06/03/2013

06/03/2013

06/03/2013

06/03/2013

06/03/2013

06/03/2013

32678

KINDER MORGAN CRUDE AND CONDENSATE LLC

Current

18092

KINDER MORGAN

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

32679

PARKWAY PIPELINE LLC

Current

18092

KINDER MORGAN

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

32688

WEST COAST TERMINAL PIPELINE (WCTP)

Current

18092

KINDER MORGAN

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

06/14/2012

38895

KINDER MORGAN SOUTHEAST TERMINALS

Current

18092

KINDER MORGAN

08/17/2012

08/17/2012

08/17/2012

08/17/2012

08/17/2012

08/17/2012

08/17/2012

08/17/2012

39023

DOUBLE EAGLE PIPELINE LLC

Current

18092

KINDER MORGAN

06/20/2013

06/20/2013

06/20/2013

06/20/2013

06/20/2013

06/20/2013

06/20/2013

Operator ID: 18092 Operator Name: SFPP, LP

AR Miles

NPMS Miles

AR Received Date

NPMS Date

Calendar Year

State

Interstate Type

2,012

NEW MEXICO

INTERSTATE

351.0

338.8

6/14/2013

2/6/2014

2,012

TEXAS

INTERSTATE

69.5

71.0

6/14/2013

2/6/2014

2,012

TEXAS

INTRASTATE

5.6

5.6

6/14/2013

2/6/2014

2,012

ARIZONA

INTERSTATE

560.9

549.5

6/14/2013

2/6/2014

2,012

CALIFORNIA

INTERSTATE

589.5

582.0

6/14/2013

2/6/2014

2,012

CALIFORNIA

INTRASTATE

1,073.7

1,082.8

6/14/2013

2/6/2014

2,012

NEVADA

INTERSTATE

78.2

75.4

6/14/2013

2/6/2014

2,012

NEVADA

INTRASTATE

7.2

5.6

6/14/2013

2/6/2014

2,012

OREGON

INTERSTATE

127.7

132.9

6/14/2013

2/6/2014

2,012

OREGON

INTRASTATE

4.3

4.4

6/14/2013

2/6/2014

2,012

2,867.7

2,847.8

6/14/2013

2/6/2014

Inspection Output (IOR)

Generated on 2015.3.12 13:05

Inspection Information

Inspection Name	KM-Portland	Operator(s)	KINDER MORGAN COCHIN LLC (32258)	Plan Submitted	--
Status	STARTED	Lead	Phillip Nguyen	Plan Approval	--
Start Year	2012	Supervisor	Terrence (Terry) Larson	All Activity Start	--
System Type	HL	Director		All Activity End	--
Protocol Set ID	HL.2012.01			Inspection Submitted	--
				Inspection Approval	--

Scope (Assets)

#	Short Label	Long Label	Asset Type	Asset IDs	Excluded Topics	Planned	Required	Total Inspected	Required % Complete
1.	UNIT 18495	PORTLAND TERMINAL TO AIRPORT	unit	18495	--	221	221	221	100.0%

a. *Percent completion excludes unanswered questions planned as "always observe".*

Plans

#	Plan Assets	Focus Directives	Involved Groups/Subgroups	Qst Type(s)	Extent Notes
1.	UNIT 18495	Baseline Procedures, Baseline Field Observations, Baseline Records, OQ Protocol 9	AR, CR, DC, EP, FS, IM, MO, PD, RPT, SRN, TD, TQ	O, P, R, S	Detail

Plan Implementations

#	Activity Name	SMART Act#	Start Date End Date	Focus Directives	Involved Groups/Subgroups	Assets	Qst Type(s)	Planned	Required	Total Inspected	Required % Complete
1.	KM-Portland Unit	--	--	n/a	AR, CR, DC, EP, FS, IM, MO, PD, RPT, SRN, TD, TQ	UNIT 18495	all types	221	221	221	100.0%

a. *Since questions may be implemented in multiple activities, but answered only once, questions may be represented more than once in this table.*

b. *Percent completion excludes unanswered questions planned as "always observe".*

Forms

No.	Entity	Form Name	Status	Date Completed	Activity Name	Asset
1.	Attendance List	KM-Portland Unit	STARTED	--	KM-Portland Unit	UNIT 18495

Results (Unsat,Concern values, 0 results)

This inspection has no matching Results.

OPERATOR QUALIFICATION
FIELD INSPECTION PROTOCOL FORM

Inspection Date(s):	2/28/2007
Name of Operator and OPID:	SFPP, LP , 18092
Inspection Location(s):	Portland, OR, Portland-Eugene Product PL
Supervisor(s) Contacted:	Sid Carr
# Qualified Employees Observed:	2
# Qualified Contractors Observed:	

Individual Observed	Title/Organization	Phone Number	Email Address
Ron Metcalf	Lead Operator; SFPP, LP	503-224-3390	
Mike McGregor	CP Tech; SFPP, LP	916-624-2431 ext 15	

To add rows, press TAB with cursor in last cell.

PHMSA/State Representative	Region/State	Email Address
Claude Allen	Western Region	claude.allen@dot.gov

To add rows, press TAB with cursor in last cell.

Remarks:
A table for recording specific tasks performed and the individuals who performed the tasks is on the last page of this form. This form is to be uploaded on to the OQBD for the appropriate operator, then imported into the file.

9.01 Covered Task Performance

Verify the qualified individuals performed the observed covered tasks in accordance with the operator's procedures or operator approved contractor procedures.

9.01 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: The employee or contractor individual(s) should be observed performing two separate covered tasks, with only one of the covered tasks being performed as a shop simulation. Obtain a copy of the procedure(s) used to perform the task(s). The individuals should be able to describe key items to be considered for correct performance of the task, and demonstrate strict compliance with procedure requirements. If a crew performing a job is observed (such as installing a service line, tapping a main and supplying gas to a meter set), the individual covered tasks should be identified and documented and the crew member performing the task(s) should be questioned as above.

Additional considerations for covered task observations:

1. Determine if procedures prepared by the operator to conduct the task(s) are present in the field and are being used as necessary to perform the task(s).
2. Confirm that the procedures being used in the field are the same (content, revision number, and/or date issued) as the latest approved procedures in the operator's O&M manual.
3. Confirm that the procedures employed by contractor individuals performing covered tasks are those approved by the operator for the tasks being performed.
4. Ensure that procedure adherence is accomplished and that "work-arounds"[1] are not employed that would invalidate the evaluation and qualification that was performed for the individual in performance of the task.
5. Determine if all of the tools and special equipment identified in procedures are present at the job site and are properly employed in the performance of the task, and if techniques and special processes specified are used as described. In certain circumstances, a contractor may operate the pipeline for an owner/operator. In that case, review which procedures have been used to qualify the individuals performing covered tasks and review records accordingly. Also ensure the "operating contractor" performs correct supervisory tasks such as reasonable cause determination.

[1] A "work-around" is a situation where the individual is using a procedure that wouldn't work the way it was written (due to an inadequate procedure or an equipment change that made the procedure steps invalid), or the individual has found a "better" way to get the job done faster instead of using the tool the way it was designed (e.g., not making depth measurements on a tapping tool because you had never drilled through the bottom of the pipe), or not taking the time to follow the manufacturer's instructions (not marking the stab depth when using a Continental coupling to join two sections of plastic pipe) because he never experienced a problem.

9.02 Qualification Status

Verify the individuals performing the observed covered tasks are currently qualified to perform the covered tasks.

9.02 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: The name of each individual observed should be noted and a subsequent review of their qualification records performed to ensure that: 1) the individual was qualified to perform the task observed; and 2) the individual's qualifications are current. A review of the evaluation requirements contained in the operator's or contractor's OQ written program should be performed to ensure that all requirements were met for the current qualification. In addition, a review of the evaluation instruments (written tests, performance evaluation checklists, etc.) may be performed to determine if any of these contain deficiencies (e.g., too few questions to ensure task knowledge, failure to address critical task requirements). Reviews of qualification records and/or evaluation instruments should ensure that AOC evaluation has been performed.

9.03 Abnormal Operating Condition Recognition and Reaction

Verify the individuals performing covered tasks are cognizant of the AOCs that are applicable to the tasks observed.

9.03 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: This inspection should focus on an individual's knowledge of the AOCs applicable to the covered task being performed and the ability to recognize and react to those AOCs. The information gained during the inspection should be compared to the requirements for qualification applied by the operator or contractor during the evaluation process for the subject covered task (e.g., knowledge of task-specific AOCs in addition to generic AOCs). If contractor individuals are observed, confirm whether the AOCs identified in the operator's written program are the ones used for qualification of the contractor individual.

9.04 Verification of Qualification

Verify the qualification records are current, and ensure the personal identification of all individuals performing covered tasks are checked, prior to task performance.

9.04 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: Supervisors, crew foremen or other persons in charge of field work must be able to verify that the qualifications of individuals performing covered tasks. This typically applies to individuals employed by the operator that are from another district or field office, where the qualification status may be unknown or uncertain, or to contractor individuals. Employee records should be made available through company databases or other means of verification, while contractors should be required to provide documentation of qualification prior to beginning work, and also provide a form of identification that is satisfactory to correlate the qualification documentation with the individual performing the task.

9.05 Program Inspection Deficiencies

Have potential issues identified by the headquarters inspection process been corrected at the operational level?

9.05 Inspection Results (type an X in exactly one cell below)		**Inspection Notes**
X	**No Issue Identified**	
	Potential Issue Identified (explain)	
	N/A (explain)	
	Not Inspected	

Guidance: If the field inspection is performed subsequent to the headquarters inspection (six months or more), the OQ database or inspection records should be checked to determine if any potential issues that were identified as having implications for incorrect task performance (e.g., no skills evaluation for tasks requiring knowledge and skills; hands-on evaluations were performed as a group as opposed to individually; span of control was not specified on a task-specific basis; evaluation and qualification on changed tasks or changed procedures not performed; inadequate provisions for, or inadequate implementation of requirements for, suspension of qualification following involvement in an incident or for reasonable cause) have been corrected.

Field Inspection Notes

The following table is provided for recording the covered tasks observed and the individuals performing those tasks.

No	Task Name	Name/ID of Individual Observed			Comments
		Ron Metcalf	Mike McGregore		
		Correct Performance (Y/N)	Correct Performance (Y/N)	Correct Performance (Y/N)	
1	Pipe Locate	X			
2	Pipe-to-soil potentia1 reading		X		
3	Electrical bond testing		X		
4					
5					
6					
7					
8					

.

POST INSPECTION MEMORANDUM

Director Approval, Chris Hoidal: _____
Inspector, Claude Allen: _____
Reviewed by: _____

Date: July 17, 2007

Operator Inspected:
SFPP, LP **Region:** Western **OPID:** 26041
500 Dallas St.
Houston, TX 77002

Executive: Mr. Ron McClain,
VP, Operations & Engineering, Phone 713-369-9000

Unit Inspected: Portland-Eugene Products PL **Unit ID:** 2995
Unit Type: Hazardous Liquid
Inspection Type: Standard (primarily O&M records); a team O&M inspection (liquid) was conducted in September 2005. The facilities inspection scheduled for July 2007 was cancelled by the Western Region Director. I performed an OQ Field Inspection Protocol 9, Form 15 for two covered tasks. However, except for checking SFPP HCAs against the PIMMA map, I did not perform a Liquid IMP Field Verification, Form 19
Record Location: Portland, OR
Inspection Dates: 2/26-28/07
AFOD: 3.0 Days total for I-01, and I-08
IOCS Activity:

Operator Contact: Steve Marositz, Manager, Codes & Standards, Pacific Region
Phone: 909-873-5146

Unit Description:
THE SEGMENT OPERATES FROM PORTLAND TO EUGENE, OR. THE UNIT HAS ONE LINE FROM PORTLAND TO EUGENE, OR (LS-14). IN ADDITION, IN PORTLAND THERE ARE SEVEN INTER-FACILITY TRANSFER LINES: LS-77, PORTLAND TO TEXACO (1.9-MILES); LS-78, PORTLAND TO UNION 8-INCH (1.21-MILES); LS-79, PORTLAND TO CHEVRON 8-INCH (1.26-MILES); LS-81, PORTLAND TO SHELL (0.98-MILES); LS-82 PORTLAND TO BP (1.79-MILES); LS-83, PORTLAND STATION TO GATX AND PORTLAND GAS (3.8-MILES); LS-84, PORTLAND TO PNO/TIME/MOBIL 8-INCH (1.99-MILES). LINE SECTION 14 CONSISTS OF AN 8" DIAMETER, 0.188" - 0.219" W.T., X-46, 114.54 MILES OF KAISER STEEL PRE-1970 ERW (LOW FREQUENCY) WITH POLYCANE WRAP COATING. THE PIPELINE WAS CONSTRUCTED IN 1962 AND HYDROTESTED TO 1600 PSI. THE MOP OF L-S 14 IS 720 PSI AND THE RELIEF VALVE IN EUGENE IS SET AT 550 PSI. THE SYSTEM INCLUDES: 4 PUMP STATIONS - 3 REMOTELY CONTROLLED STATIONS (FARGO, SALEM, AND MORGAN) AND 1 MANNED STATION (PORTLAND). THERE IS ONE TERMINAL AND IT LOCATED IN EUGENE, OR. ALL MAINLINE VALVES

ARE ANSI 600. THE COMMODITIES CONSIST OF UNLEADED AND DIESEL. ALL THE PRODUCTS COME FROM VARIOUS BREAKOUT TANKS IN PORTLAND, OR (CHEVRON, SHELL, KMLT, UNICAL/TOSCO, VALERO, AND BP). ALL PIPELINE MILES FROM PORTLAND, OR TO EUGENE, OR HAS BEEN SMART PIG BY ROSEN ON MAY 23, 2000 WITH NO ANOMALIES GREATER THAN 30%. A GEOMETRY TOOL WAS ALSO RUN IN MAY 20, 2000. THE PIPELINE IS SCHEDULED FOR A MFL TOOL RUN IN SEPTEMBER 2005. THE SYSTEM HAS CATHODIC PROTECTION SERVED BY 8 RECTIFIERS. THE SYSTEM USED TO HAVE A BREAKOUT TANK IN EUGENE. THIS TANK NO LONGER QUALIFIES THE DEFINITION OF A BREAKOUT TANK SINCE THE JURISDICTIONAL LINE (LS-85) LEAVING THE TANK WAS DECOMMISSIONED IN 2003. IN 2003, FOLLOWING SCC INDICATION, THE MOP WAS REDUCED FROM 1440 PSI TO 720 PSI.

Facilities Inspected: I thoroughly inspected the operators O&M records. However, my facility inspection was abbreviated by my supervisor. I inspected LS-82 and LS-83 at the BP Terminal. In addition I observed the Lead Operator, Ron Metcalf, perform a line locate on LS-78 with a Metrotech 9890 at the intersection of Doane and Front Streets, and the CP Tech perform bond reads, and P/S reads.

Persons Interviewed:

Sid Carr	Area Manager (for Pipeline)	(503) 689-1545
Larry Hosler	Manager, Pipeline Maintenance	(707) 580-5766
Ron Metcalf	Lead Operator	(503) 220-1254
Mike McGregor	CP Tech	(916) 624-2431
Steve Marositz	Manager, Codes & Standards	(909) 873-5146
Lee Heppner	OQ Coordinator, Western Region	(916) 215-2255

Probable Violations/Comments/Recommendations:

1) SFPP operates an 8-inch transfer lines (LS-82 and LS-83) from the BP/ARCO terminal to SFPP's pump station. BP operates two high-output rectifiers with deep-well anodes at the terminal to cathodically protect their facility; however, this rectifier has potential to cause electrical interference on LS-82 and LS-83. In 2005 the P/S on LS-82 near the terminal (MP 2.202 and MP 2.25) was -5.710 and -7.090 respectively. SFPP installed NiCr wire bonds to BP's rectifier—these are considered critical bonds.

   At the time of inspection I recorded the following P/S (on) readings inside or near BP' terminal: -4.27V near the beginning of LS-83 near BP's rectifier; -1.78V at MP 2.17 on LS-82; and 2.12V on LS-82 near BP's rectifier. The SFPP CP tech read 2.18 A current from BP's rectifier to LS-82 and 2.28 A current from BP's rectifier to LS-83. In effect BP is cathodically protecting most pipelines (their own and foreign) in the vicinity of their terminal through electrical bonds, but BP's rectifiers are potentially a source of damaging interference to those pipelines not bonded to them. BP's interference to other underground structures may be contrary to 195.577(b). **I recommend that the next inspector**

follow-up on SFPP's efforts to ameliorate interference from BP.

2) Maintain normal inspection frequency

Attachments: Abbreviated Procedures Inspection Report, OQ Field Inspection Protocol 9 Form 15

POST-INSPECTION MEMORANDUM

Director Approval: **Edward J. Ondak** _____

Inspector Approval: **Joseph P. Robertson** _____

TRACKING NUMBER: _____

SANTA FE PACIFIC PIPELINE CO **Opid: 18519** **Region:** Western
PORTLAND-EUGENE PRODUCTS PIPELINE **UREC: 299**
1830 SIERRA GARDENS DRIVE, SUITE 20
ROSEVILLE, CA 95661

Contact: STEVE TOSTENGARD, DISTRICT DIRECTOR

Phone: 916-782-9018 **Emergency Phone:** **Fax:** 916-782-9028
Location and Type: ROCKLIN, CA, DISTRICT OFFICES, INTRASTATE LIQUIDS
State-Jurisdiction: OR-F
Commodities: PETROLEUM PRODUCTS

Records: RECORDS ARE LOCATED IN ROCKLIN, CA

Segment: THIS SEGMENT OPERATES FROM PORTLAND, OR TO EUGENE, OR. THE PIPELINE IS 115 MILES LONG, 8" DIA., WT. .188"-.219", THE MOP IS 1280 PSIG. THE SYSTEM INCLUDES: 4 PUMP STATION, 3 REMOTE CONTROL; PUMP STATIONS AND 1 MANED STATION IN PORTLAND; TWO TERMINALS, 1 IN ALBANY, OR AND 1 IN EUGENE, OR.

Notes: ALL RECORDS AREA MAINTAINED IN THE DISTRICT OFFICES.,
Inspected: NOVEMBER 18-22, 1996 **AFO Days:** 9.0 **IREC:** 6683

Inspector: ROBERTSON/KATCHMAR

Type: STANDARD **Frequency:** NORMAL

Notes: O&M, AND EMERGENCY MANUALS WERE REVIEWED ALONG WITH ALL AVAILABLE RECORDS. FIELD INSPECTION INCLUDED CP READINGS ALONG PIPELINE AND OVERALL INSPECTIONS OF THE PUMP STATIONS. PERSONNEL APPEAR TO BE KNOWLEDGEABLE IN THEIR AREAS OF EXPERTISE. ALL UNIT INFORMATION HAS BEEN UPDATED AND IS CORRECT AS OF THIS INSPECTION.

RECOMMENDATIONS

1. ISSUE A NOTICE OF PROBABLE VIOLATION, WARNING LETTER TO SANTA FE PACIFIC PIPELINE COMPANY FOR THE FOLLOWING:

   -195.402 (a) A REVIEW OF SANTA FE PACIFIC COMPANY'S RECORDS FAILED TO PRODUCE DOCUMENTATION THAT INDICATED SANTA FE PACIFIC COMPANY REVIEWED ITS O&M MANUAL ON A ANNUAL BASIS.
   -195.402 (c)(12) A REVIEW OF SANTA FE PACIFIC COMPANY'S RECORDS FAILED TO PRODUCE DOCUMENTATION THAT INDICATED SANTA FE PACIFIC COMPANY MAINTAINED LIAISON WITH THE PUBLIC OFFICIALS ALONG ITS PIPELINE RIGHT-OF-WAY.

2. ISSUE A NOTICE OF PROBABLE VIOLATION, NOTICE OF AMENDMENT LETTER TO SANTA FE PACIFIC COMPANY FOR THE FOLLOWING:

   -195.402(C) (10) SANTA FE PACIFIC COMPANY'S ABANDONMENT PROCEDURES WERE INADEQUATE IN THAT THE DID NOT MEET THE REQUIREMENTS OF 195.402 (C) (10).
   -195.406 SANTA FE PACIFIC COMPANY'S MOP PROCEDURES WERE INADEQUATE IN THAT THE DID NOT MEET THE REQUIREMENTS OF 195.406.
   -195.416 SANTA FE PACIFIC COMPANY'S CORROSION CONTROL PROCEDURES WERE INADEQUATE IN THAT THE DID NOT CONSIDER IR-DROP IN THEIR INTERPRETATION OF THE ANNUAL MEASUREMENTS.
   -195.436 SANTA FE PACIFIC COMPANY DID NOT HAVE ADEQUATE PROCEDURES ADDRESSING THE SECURITY OF THEIR FACILITIES.
   -195.442 SANTA FE PACIFIC COMPANY DID NOT HAVE ADEQUATE PROCEDURES ADDRESSING DAMAGE PREVENTION..

ATTACHMENTS

1. EVALUATION REPORT OF A LIQUID PIPELINE CARRIER.
2. NOTICE OF AMENDMENT TO THE OPERATOR.
3. MAP OF SANTA FE PACIFIC COMPANY'S FACILITIES.

OFFICE OF THE STATE FIRE MARSHAL

California Department of Forestry and Fire Protection

FROM THE DESK OF:

Bob Gorham
Pipeline Safety Division
3950 Paramount Blvd. Suite 210
Lakewood, CA 90712
(562) 497-9100
(562) 497-9104 FAX

03-19-04PC1:34 RCVD

To: Tom Finch To Chris Hoidal thru Pete Katchanian

OPS

☐ **Urgent** x **For Review** ☐ **Please Comment** ☐ **Please Reply** **Per Your Request**

- **Comments:**

Tom enclosed is valve placement and spacing for KM Concord to Sacto pipeline.

I would like to receive comments back by March 24 if possible.

Bob

SPEC Services, Inc.
17101 Bushard Street
Fountain Valley, CA 92708-2833
(714) 963-8077, FAX (714) 963-0364
info@specservices.com

DRAWING AND SPECIFICATION TRANSMITTAL

California State Lands Commission
100 Howe Avenue, Suite 100-South
Sacramento, CA 95825

March 9, 2004
SPEC Job No. 2610
Kinder Morgan Energy Partners, L.P.
Concord to Sacramento Pipeline

Attention: Mr. Eric Gillies

Dear Mr. Gillies:

The following information is enclosed for your review and approval:

QTY.	DWG. NO.	DESCRIPTION
1	---	Mitigation Measure S-2C Compliance Package

Transmitted by:

Chris Smart
CS:alm

cc: Chandrashekar Basavalinganadoddi (w/attach) - CSLC
Bob Gorham (w/attach) - CSFM
Jill Jefferson (w/attach) - KMEP
Kim Henry - SPEC
Project File (w/attach)

(California Overnight)

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Requirement

At least 60 days prior to beginning construction, SFPP shall provide to the CSLC and the California State Fire Marshal for review and approval the documentation on all pipeline valves (including those added as a result of analytical assessment of the fault crossings and ground settlement and this mitigation measure in the EIR), locations, technical specifications, foundation design details and piping and instrumentation diagrams, etc. The submittal shall include the following:

- A detailed pipeline profile that clearly illustrates the topography, valve locations, and proposed method of actuation, along the final route.
- The Applicant shall analyze at least 50 low points along the pipeline. The analyses shall be similar to those provided in Section D.2.3.7 for four spill scenarios. Where manual valves are being proposed, the affect of converting the valve to remote or automatic operation shall be presented. Where converting a valve from manual to remote or automatic operation would result in a significant reduction in spill volume, the Applicant shall either convert the valve to remote or automatic operation, or provide a compelling feasibility discussion. (At least one low point shall be analyzed between each set of proposed valves. The points selected for analysis shall be representative and shall be spread relatively evenly along the pipeline. Environmentally sensitive receptors shall be analyzed.)
- Specific information on the location of the proposed check valve at MP 20.1. An analysis shall be conducted to determine if the check valve would be more effective if it were relocated upstream of the hill which rises to an elevation of about 80 feet.

Compliance

As required by the mitigation, a leak analysis has been performed at low points and between proposed valve locations along the route. As the pipeline profile is relatively flat, only twenty-seven (27) assumed rupture locations were required to assess worst case release scenarios. The attached profile shows the location of each of the assumed rupture locations. The attached Table No. 1 summarizes the worst-case release volumes and compares them to release volumes from a hypothetical design where all proposed valves are motorized for automatic shut-down. The calculation table includes notes that describe the calculation basis and clarify the results.

Based on the results of the initial analysis, it was determined that modifications to the originally proposed valve design would significantly reduce release volumes at a few specific locations along the route. As shown on the attached profile drawing, one new MOV (MP 39.5) and two new check valves (MP 30.84 and MP 68.0) have been added. A revised leak analysis was performed with these additional valves included and the results are summarized on the attached Table No. 2.

As shown on Table No. 2, the comparison of release volumes with the modified valve design to that of the hypothetical design where all manual valves are motorized is no longer significantly different. SFPP proposes to proceed with the incorporation of the additional valves (1-MOV and 2-check) into the project design of this project.

OFFICE OF THE STATE FIRE MARSHAL

California Department of Forestry and Fire Protection

FROM THE DESK OF:

Bob Gorham
Pipeline Safety Division
3950 Paramount Blvd. Suite 210
Lakewood, CA 90712
(562) 497-9100
(562) 497-9104 FAX

03-19-04P01:34 RCVD

To: Tom Finch To Chris Hoidal thru Pete Katchanes

OPS

☐ **Urgent** x **For Review** ☐ **Please Comment** ☐ **Please Reply** **Per Your Request**

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DRAWING AND SPECIFICATION TRANSMITTAL

California State Lands Commission
100 Howe Avenue, Suite 100-South
Sacramento, CA 95825

March 9, 2004
SPEC Job No. 2610
Kinder Morgan Energy Partners, L.P.
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Kim Henry - SPEC
Project File (w/attach)

(California Overnight)

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- Specific information on the location of the proposed check valve at MP 20.1. An analysis shall be conducted to determine if the check valve would be more effective if it were relocated upstream of the hill which rises to an elevation of about 80 feet.

Compliance

As required by the mitigation, a leak analysis has been performed at low points and between proposed valve locations along the route. As the pipeline profile is relatively flat, only twenty-seven (27) assumed rupture locations were required to assess worst case release scenarios. The attached profile shows the location of each of the assumed rupture locations. The attached Table No. 1 summarizes the worst-case release volumes and compares them to release volumes from a hypothetical design where all proposed valves are motorized for automatic shut-down. The calculation table includes notes that describe the calculation basis and clarify the results.

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SFPP Concord to Sacramento Pipeline Project
Mitigation Measure S-2c: Valve Review
Table No. 1 - Leak Analysis (Original Valve Layout)
Variable Release Volume Due To Gravity Drainage

Original Valve Layout and Assumed Leak Locations		Leak Analysis with Original Valve Design			Leak Analysis with all Manual Valves Converted to MOV's			Release Volume Reduction with Motor Operated Valves
			Column "A"	Column "B"		Column "C"	Column "D"	Column "E"
Description	Valve Elev. / Leak Elev.	Pipe Length Subject to Gravity Drain at each Leak Location (Note 2) (feet)	Max. Product Release at each Leak Location (bbls)	Anticipated Product Release at each Leak Location (Note 3) (bbls)	Pipe Length Subject to Gravity Drain at each Leak Location (Note 2) (feet)	Max. Product Release at each Leak Location (bbls)	Anticipated Product Release at each Leak Location (Note 3) (bbls)	Release Reduction with all Motor Operated Valves (Column "B" - Column "D") (bbls)
Valve - Motor Operated (V1) (Concord Station)	[redacted]							
Leak Point #1 (L1)		1,149	414	248	1,149	414	248	0
Valve - Manual (V2) (East of Walnut/Grayson Crk)								
Leak Point #2 (L2)		353	127	76	353	127	76	0
Leak Point #3 (L3)		749	270	162	612	220	132	30
Valve - Motor Operated (V3) (West of Walnut/Grayson Crk)								
Leak Point #4 (L4)		1,044	376	225	1,044	376	225	0
Leak Point #5 (L5)		2,385	858	515	2,385	858	515	0
Leak Point #6 (L6)		3,957	1,424	855	3,957	1,424	855	0
Valve - Motor Operated (V4) (ST Services - Launch/Recvr)								
Leak Point #7 (L7)		4,872	1,754	1,052	4,872	1,754	1,052	0
Valve - Manual (V5A) (14' South of Carquinez Strait)								
Leak Point #8 (L8)		5,812	2,092	1,255	4,632	1,667	1,000	255
Valve - Motor Operated (V5) (14' North of Carquinez Strait)								
Leak Point #9 (L9)		3,712	1,336	802	3,712	1,336	802	0
Leak Point #10 (L10)		1,816	654	392	1,816	654	392	0
Valve - Motor Operated (V6) (North of Lake Herman Rd)								
Leak Point #11 (L11)		1,470	529	317	1,470	529	317	0
Valve - Check (V7) (West of Lopes Rd)								
Leak Point #12 (L12)		1,986	715	429	1,986	715	429	0
Valve - Check (V8) (West of Lopes Rd - GV Fault)								
Leak Point #13 (L13)		3,493	1,257	754	3,493	1,257	754	
Leak Point #14 (L14)		5,975	2,151	1,290	5,375	1,935	1,161	130
Leak Point #15 (L15)		4,499	1,620	972	3,764	1,355	813	159
Valve - Check (V10) (East of Cordelia Slough)								
Leak Point #16 (L16)		6,132	2,207	1,324	6,132	2,207	1,324	0
Valve - Motor Operated (V11) (City of Fairfield)								
Proposed Valve - Check (V11A) (East of Peabody Road)								
Leak Point #17 (L17)		8,065	2,903	1,742	8,065	2,903	1,742	0
Leak Point #18 (L18)		8,656	3,116	1,869	8,656	3,116	1,869	0
Leak Point #18A (L18A)		10,439	3,758	2,255	5,304	1,909	1,145	1,109
Valve - Manual (V12) (Meridian Road)								
Proposed Valve - Motor Operated (V12A) (West of Rio Dixon Rd)								
Leak Point #19 (L19)		1,634	585	351	1,462	526	316	35
Valve - Manual (V13) (Bunker Station Road)								
Leak Point #20 (L20)		6,311	2,272	1,363	3,250	1,170	702	661
Leak Point #21 (L21)		5,892	2,121	1,272	3,603	1,297	778	494
Valve - Manual (V14) (Yolo County - Road 106)								
Leak Point #22 (L22)		10,988	3,955	2,373	5,088	1,831	1,099	1,274
Leak Point #23 (L23)		6,494	2,338	1,403	6,372	2,294	1,376	26
Valve - Manual (V15) (West of Yolo Bypass)								
Leak Point #24 (L24)		3,753	1,351	811	3,737	1,345	807	3
Valve - Motor Operated (V16) (East of Yolo Bypass)								
Proposed Valve - Check (V16) (West of Holyoke Drive)								
Leak Point #25 (L25)		6,850	2,466	1,479	6,850	2,466	1,479	0
Leak Point #26 (L26)		4,465	1,607	964	4,465	1,607	964	0

(b) (7)(F)

Notes:

1 The above table summarizes variable release volumes based on gravity drainage at selected "worst-case" low point rupture locations along the route. These volumes assume a complete rupture scenario without flow restraint. In addition to this variable release volume component, there is also a fixed release volume component that is not accounted for in the table. This fixed release volume will occur prior to the closure of system motor operated valves (MOV's). Based on a MOV closure time of 2.25 minutes and an average system flowrate of 7300 BPH, this fixed release volume will be 274 barrels. This fixed release volume is additive to the variable release volumes summarized in the table and would be constant for any rupture location.

2 Once system MOV's have been closed, relative pipe elevation and gravity will determine how much volume is subject to release at a given rupture location. A review of the pipeline profile was performed to determine the length of pipe on either side of the rupture that would be subject to drainage based on relative elevation differences. The total pipe length that would be subject to drainage is summarized in the table.

3 As discussed in the Project FEIR (page D.2-13), a pipeline rupture in a closed system results in natural siphons being created that prevent a large portion of the pipeline volume subject to gravity drainage from being released. It is SFPP's experience in pipeline draindowns required for various maintenance and relocation activities that this gravity draindown is equivalent to 60% of the actual volume subject to drainage. This 60% factor has been used in the table to reflect anticipated release volumes.

4 Although it is impossible to predict the exact response time, SFPP personnel will be dispatched immediately to close manual valves in the event of a pipeline rupture. The closure of manual valves in addition to the automatic closure of MOV's will reduce the release volumes summarized on the table.

(b) (7)(F)

STANCE IN MILES. STATIONING NUMBERS

LEGEND:

[S] STATION AND/OR TERMINAL

[V] MAINLINE BLOCK VALVE

L# – LEAK ANALISYS SITE NUMBER

MOV [V] REMOTE CONTROLLED VALVE

CHK [V] MAINLINE CHECK VALVE

(110) PIPELINE MILE POST

[123+45] PIPELINE STATIONING FROM ALIGNMENT SHEETS

LINE SECTION 130

SCALE:

HORIZONTAL: 1"=2

VERTICAL: 1"=1(

(b) (7)(F)

100

0

L.P

ORANGE CALIFORNIA

CONCORD TO SACRAMENTO
L.S. 130 VALVE PROFILE
LEAK ANALYSIS

2610-X-PF-130C

2 4

100' 200'

SPEC SERVICES

SPEC Services, Inc.
17101 Bushard Street
Fountain Valley, CA 92708
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NO.	DATE	REVISIONS	BY	CHECKED	MGR-P/L ENGINEERING
A	03/10/04	ISSUED FOR CSLC REVIEW			

(b) (7)(F)

1000 1500 2000 2500 3000 3500 4000 4500 5000 5500 6000

ELEVATION (FEET)

(b) (7)(F)

[redacted]

Segment Identification and Completeness Check Inspection

Final Post-Inspection Report

Report Issue Date:	March 22, 2002 (original draft issued January 22, 2002)
Operator:	Kinder Morgan Energy Partners LP
Corporate Address:	500 Dallas St. Suite 500 Houston, TX 77002
Operator ID Number(s):	CalNev Pipeline - 26125 Santa Fe Pacific Pipeline - 18092 Central Florida Pipeline - 2190 Plantation Pipeline System - 15674 CO2 Pipeline - 31555 KMI Texas Liquids - 30551 KM Liquids Terminal - 26041 MidCon (North) Pipeline System - 4472
Date of Inspection:	January 15 - 17, 2002
Location of Inspection:	Kinder Morgan Inc., Offices 370 Van Gordon Street Lakewood, CO 80228-8304
Primary Contact:	Edward (Buzz) Fant, Director, Pipeline Integrity and Safety
Primary Contact Phone and Fax Numbers:	Phone: 713-369-9454. Fax:713-495-2713
Operator Personnel Participants:	Brad Lewis, Manager, Corrosion Control and Risk Management Scott Davis, Manager, Pipeline Integrity and Maintenance Bruce Hancock, Manager, Codes and Standards Steve Biagiotti, Bass-Trigon Software (Contractor to KMEP) Edward Kelley, Bass-Trigon Software (Contractor to KMEP)

OPS Inspection Team Representatives: Peter Katchmar (Western Region)
Derick Turner (Southern Region)
Wayne St. Germain (TSI)
Robert Brown (Cycla Corporation, Contractor to OPS)
David Kuhtenia (Cycla Corporation, Contractor to OPS)

Inspection Objectives: The purpose of this inspection was to assure Kinder Morgan Energy Partners LP (KMEP) has identified segments on its pipelines that can affect High Consequence Areas as required by 195.452 (b) (1) (i). This inspection also included a summary level review of KMEP's Integrity Management Framework to ascertain their level of progress in meeting the Integrity Management Program requirements in 195.452 (f). The results from both the segment identification and completeness check portions of this inspection will be used to plan and schedule the upcoming Comprehensive Integrity Management Program Review.

Summary of Segment Identification Process: The OPS approach to inspect KMEP's identification of pipeline segments that could affect HCAs involved two steps. The first step was to review the technical approach used to define these segment boundaries, including the justifications for any assumptions used in the segment determination. The second step was to verify that KMEP performed the segment identification effort in a manner consistent with its described approach. In conducting this verification, the OPS inspection team examined a limited number of KMEP's segment identification results for a variety of different specific locations where the pipeline intersected, or was in close proximity to, different types of HCAs. OPS may conduct more in-depth reviews of the segment identification process and conduct additional verification of segment locations during the Comprehensive Integrity Management Program inspections.

KMEP used the RiskCAT data extraction software (a Bass-Trigon Software product) to determine the locations where the KMEP pipelines could affect HCAs. The methodology used HCA shape file information from the NPMS along with the location of KMEP's pipelines to determine the following:

- Portions of the pipeline where the line intersects an HCA (termed "direct impact areas" by KMEP).
- Portions of the pipeline outside of HCA boundaries where a failure could affect an HCA by spreading outward from the failure site (termed "indirect impact areas" by KMEP). For this determination, KMEP determined the rupture volume at 30 foot increments along the line. This rupture volume was assumed to spread uniformly on the ground around the line with a 1-inch thickness. If this "pool" intersects an HCA, it was presumed that the pipeline could impact the HCA. This calculation assumed flat ground, and used "worst

case assumptions" for determining spill volume (i.e., 100% drain down between two isolation valves or "high elevation points" on the line).

- Portions of the pipeline outside of HCA boundaries where a spill could affect an HCA by transport via a stream, river, or drainage area (termed "transport area" by KMEP). This third category accounts for local topography. Digital Elevation Models were acquired at a 30 meter resolution for the areas in which KMEP systems are located. An elevation grid from these DEM's was overlaid onto the pipeline map. Using a computerized vector analysis, the migration of product from grid-to-grid was modeled. This modeling was performed for all locations where the slope exceeded 2%.

In addition to the visual display showing the location of the line segments that can affect HCAs, KMEP prepared a comprehensive listing of each segment defined by the beginning and ending engineering stations that is being used in its risk analysis and data integration software. These tables were provided for each pipeline system.

Summary of Completeness Check: At the time this inspection was conducted, KMEP was in the process of preparing its Integrity Management Program Manual. The OPS inspection team reviewed a partial draft of this document. Most sections were either in outline format or at a very preliminary state of documentation. The Baseline Assessment Plans had not been prepared. OPS informed KMEP that it does not expect KMEP to have a fully developed, mature, and completely documented Integrity Management Program by March 31, 2002. Instead OPS expects to see a Framework that addresses each of the program elements in 195.452 (f). This framework must describe the processes currently in use for each program element as well as KMEP's plans for further improving their processes as it develops a more mature program over time. OPS provided feedback on areas where additional specificity in the program documentation will be expected during the Comprehensive Program Review.

Although, KMEP has not established its Baseline Assessment Plan, it indicated that it intends to utilize high resolution MFL In-Line Inspection (ILI) tools. It currently is using Rosen as its ILI tool vendor.

OPS Feedback: The OPS inspection team provided the following feedback to KMEP during the exit interview.

- KMEP should have verified the pipeline data that it downloaded from NPMS to perform the segment identification process. As discovered during the validation, a portion of the "Rocklin to Reno" line from the California border to Reno was missing from the NPMS data and therefore not addressed in the segment identification process. Similarly, there is a concern that the 8 and 14 inch CalNev lines that originate in San Bernardino may not be

accurately located in the data KMEP is using to identify its segments that can affect HCAs.

- KMEP did not adequately identify segments that could impact USAs in the states where USAs were not mapped in NPMS. Of the states in which KMEP operates, 8 states had no drinking water USA maps in NPMS and 5 states had no ecological USA maps. KMEP is relying on information in the OPA Spill Response Plans for meeting the December 31, 2001 segment identification deadline. While the use of the OPA Plan information is a reasonable and prudent approach for identifying drinking water and environmental resources, the segment identification based on this information was not acceptable. The information in the OPA Spill Response Plan that was reviewed only identified environmental and drinking water resources near the pipeline. It did not (in most cases) identify the portion of the line pipe where a failure could impact these resources. KMEP had not extracted any listing of segments that could affect drinking water or ecological USAs from its Spill Response Plans. KMEP indicated that it will use the information in the OPA Spill Response Plans to define segments by March 31, 2002, if the NPMS USA maps are not available. The process by which the OPA Plan information will be used for segment identification has not been established.

- KMEP's segment identification process did not adequately consider facilities (e.g., terminals and pump stations) in its analysis. In some scenarios, the volume of product in storage tanks might be an important consideration in determining spill volume and extent of transport for line pipe failures. In addition, failures at the facilities themselves should be evaluated to determine whether they could impact HCAs at these locations. A comprehensive review of all portions of a pipeline system where a failures might impact HCAs should result in a list of facilities at which failures could impact HCAs.

- Although OPS may examine the analysis and technical justification in more detail during the Comprehensive Program Reviews, the use of Manning's Kinematic equation for spill transport on dry land appears reasonable. However, for spills that enter streams and other waterways that could transport the spilled product to an HCA, the assumption of a 1 mile limit on the extent of product transport is not adequately justified. KMEP has indicated that they intend to look at transport of spilled product via streams and waterways in more detail as they review and refine the segment identification analyses.

- The use of the C-FER model to address impact areas from HVL's appears reasonable. However, this model may not adequately address asphyxiation hazards from gases that are heavier than air and could settle in low lying areas. OPS suggested that KMEP consider the analysis done for the Cortez CO2 line as part of the Risk Management Demonstration Project as a potential source of useful information.

- KMEP is considering performance of some sensitivity studies to see how changes in some of the assumptions used in the segment identification process might affect the results. OPS supports this and recommends that KMEP examine break scenarios that have more likely break sizes as well as different controller response times to detect a failure and isolate the line.

- KMEP did not identify segments that could affect HCAs for its idle pipelines.

- While OPS recognizes that the segment identification process documentation was not required by December 31, 2001, based on the review of the process description provided, it is recommended that the documentation provide significantly more detail and specificity in describing the steps in the analysis, the assumptions that were made, and the technical justification for the assumptions. When the process documentation is complete it should also identify the positions responsible for performing this work.

- The segment identification process also needs to provide additional detail on how KMEP will periodically review the boundaries of line segments that can affect HCAs, and make adjustments as necessary. This process should address both the annual internal KMEP reviews and checking NPMS for updates.

- KMEP appears to have a good understanding of the rule's program requirements. The partial draft of KMEP's Integrity Management Program Manual appears to capture all of the program elements in 195.452 (f). Because it was an incomplete draft, much of the detail and process descriptions expected in a fully documented program was not available. Some suggestions on areas to include in the final document were provided. OPS believes it is important the framework identify improvements in the individual processes that KMEP plans to make as it develops a more complete, mature, and institutionalized program.

- As KMEP develops its approach for Integrity Management documentation and records retention, it is important to remember that changes to the boundaries of segments that can affect HCAs, changes to the Baseline Assessment Plan, and other key areas need to be documented along with the basis for such changes. The Integrity Management Program should be integrated with the KMEP's Management of Change process.

- The Integrity Management Program Manual should address training and qualifications for personnel responsible for reviewing integrity assessment results and conducting the information (or risk) analysis [per 195.452 (f) (8)]. OPS realizes that KMEP currently relies on highly experience personnel to perform these important functions. However, it is

important that the company move toward a more structured, formal, and documented approach to assuring personnel performing this work have the requisite level of experience and training.

Potential Noteworthy Practices: The use of the RiskCAT software and the underlying technical basis for spill migration modeling is a comprehensive approach to identifying which portions of the pipeline can impact an HCA. It allows KMEP to appropriately consider the location-specific factors that are important to understanding how a failure at any given point in the line might affect nearby HCAs, as required in 195.452 (f) (1). This methodology should provide valuable input to the subsequent risk analysis process. In particular the location-specific release volume calculations should be very useful in addressing the need for EFRDs and other mitigative actions required by this rule.

The visual mapping of the pipeline segments by direct, indirect, and transport was extremely helpful in communicating the methodology and the results. The Visio drawings are likewise a very beneficial communication device.

POST INSPECTION MEMORANDUM

Inspector: Phillip Nguyen_____
Supervisor: Terry Larson_____
Follow up enforcement: None
Director Approval: Yes / No

Date: August 21, 2012

Operator Inspected: **OpID:** 32258 **Region:** Western
Kinder Morgan Cochin, LLC
500 Dallas, Suite 1000
Houston, TX 77002

Unit Address:
5880 NW St Helens Road
Portland, OR 97210

Units Inspected: Portland Terminal to Airport

Units ID: 18495

Units Type: Intrastate Liquid
Inspection Type: I01 Unit
Record Location: Portland, OR
Inspection Dates: 06/18-21/2012
AFOD: 4.0
SMART Activity ID Number: 138118

Operator Contact: Jeff Hibner, Aera Manager
Phone: (503)220-1263 **Fax:** (503)220-1270 **Emergency:** (213)624-9461

Unit Description:
Kinder Morgan owns and operates a 8" pipeline for about 9 miles long from Kinder Morgan Willbridge Station to the Portland airport. It crosses the Willamette River. It is API 5L X42 pipe, with 0.219" pipe WT, and 0.500" WT for portion of the river crossing pipe.

Facilities Inspected:
O&M manual, emergency procedures, records review, and a field inspection of the pipeline ROW from Willbridge pump station to the airport delivery location.

Persons Interviewed:
Jeff Hibner, Aera Manager
Ron Metcalf, Assistant Area Manager

Curtis Parker, Compliance Specialist Pacific Northern Region
Andrew Holbrook, Operations Manager, Northwest
James Eggenberger, Corrosion Manager

Probable Violations/Concerns:
None.

Previous Violations/Concerns Follow Up:
None

Recommendations:
It is proposed to keep the Unit inspection at regular cycle.

Attachments:
IA Inspection Information Summary (one page)

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