PACIFIC ENERGY

March 5, 2009

05-04-09A07:25 RCVD

Mr. Chris Hoidal, P.E.
Regional Director, Western Region
Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration (PHMSA)
12300 West Dakota Avenue, Suite 110
Lakewood, Colorado 80228

RE: CPF 5-2008-7002M, Dated November 14, 2008
CPF 5-2008-5034M, Dated September 15, 2008

Dear Mr. Hoidal,

Pacific Energy Resources Ltd has completely addressed the "NOTICE OF AMENDMENT" (NOA), CPF 5-2008-7002M, dated November 14, 2008. The NOA was a result of a pipeline Integrity Management Program (IMP) inspection of the Pacific Energy Resources Ltd (PERL) facilities and records, performed May 19-22, 2008 by representatives of Office of Pipeline Safety (OPS) and California State Fire Marshall (CSFM).

Pacific Energy Resources Ltd has also completely addressed the "NOTICE OF AMENDMENT" (NOA), CPF 5-2008-5034M, dated September 15, 2008. The CPF was a result of an inspection of our Operations and Maintenance (O&M) Procedural Manual in Long Beach, California performed May 19-22, 2008 by a representative of Office of Pipeline Safety (OPS).

All of the revisions have been made to the PER Company IMP and O&M Manuals. A copy of the revisions is included for your review.

Should you have any immediate questions, please feel free to contact Mr. Rick Armstrong, DOT Specialist in our Long Beach, California office at (310) 560-5281.

If you need to contact me personally, I can be reached at: (562) 628-1540.

Sincerely,

Robert M. Pyle
Manager
Pipeline & Marine Logistics
Pacific Energy Resources, Ltd.

CPF 5-2008-5034M

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

September 15, 2008

Mr. Robert Pyle
Manager, Pipeline and Marine Logistics
Pacific Energy Resources LTD
111 West Ocean Blvd., Suite 1240
Long Beach, CA 90802

CPF 5-2008-5034M

Dear Mr. Pyle:

On August 25-27, 2008, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) pursuant to Chapter 601 of 49 United States Code inspected Pacific Energy Resources' procedures for Operations and Maintenance (O&M) Procedural Manuals in Long Beach California.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within Pacific Energy Resources' plans or procedures, as described below:

1. **§195.214 Welding procedures**

   (a) Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the ASME Boiler and Pressure Vessel Code (ibr, see § 195.3) . The quality of the test welds used to qualify the welding procedure shall be determined by destructive testing.

Pacific Energy Resources is not specific in its O&M manuals regarding what section and edition of API 1104 need to be used to qualify its 'Welding Procedures'.

2. **§195.222 Welders: Qualification of welders.**

(a) Each welder must be qualified in accordance with section 6 of API 1104 (ibr, see §195.3 or section IX of the ASME Boiler and Pressure Vessel Code, (ibr, see § 195.3) except that a welder qualified under an earlier edition than listed in § 195.3 may weld but may not re-qualify under that earlier edition.

Pacific Energy Resources requires its welder to be qualified under Section 3 of API 1104. CFR 49 Part 195.222 requires all welders to be qualified under Section 6 of API 1104. Pacific Energy needs to change its O&M procedural manual to reference Section 6 and specify the correct edition of API 1104.

3. **§195.228 Welds and welding inspection: Standards of acceptability.**

(b) The acceptability of a weld is determined according to the standards in Section 9 of API 1104. However, if a girth weld is unacceptable under those standards for a reason other than a crack, and if Appendix A to API 1104 (ibr, see § 195.3) applies to the weld, the acceptability of the weld may be determined under that appendix.

Pacific Energy Resources requires its weld acceptability to be inspected under Section 6 of API 1104. CFR 49 Part 195.288 requires weld inspection to be performed under Section 9 of API 1104. Pacific Energy needs to change its O&M procedural manual to reference Section 9 and specify the correct edition of API 1104.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 60 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 5-2008-5034M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 H. Monfared (#122435)

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*

CPF 5-2008-5034M
Line 1 and 2

PIPELINE WELDING

1. REFERENCE

49 CFR, Sections 195.208, 195.214, 195.216, 195.222, 195.224, 195.226, 195.228, 195.230, and 195.422(a).

2. PURPOSE

To establish the requirements for qualifying welding procedure and welders for work on steel pipelines.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (274) _______________ is responsible to confirm that all pipeline welding is performed in accordance with this procedure.

The (275) _______________ is responsible for reviewing and approving all qualified welding procedures prior to start of production welding.

The (276) _______________ is responsible for retaining and maintaining a current record of approved welders, their identification numbers, and the procedures to which each welder is qualified.

4. GENERAL

4.1 All welding to be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 (19^{th} Edition) or Section IX of the ASME Boiler and Pressure Vessel Code(See § 195.3) to produce welds meeting the requirements specified. The quality of the tests used to qualify the procedure shall be determined by destructive testing. Each welding procedure must be recorded in detail, including the results of the qualifying tests. This record must be retained and followed whenever the procedure is used.

4.2 A Welding Procedure Specification (WPS) is a written procedure prepared to provide direction for making production welds to specific requirements. It specifies the materials, consumables, and procedures to be used in making welds, either for a variety or for specific connection geometry, steel types and steel thickness.

4.3 The Procedure Qualification Record (PQR) documents the welding materials, consumables, and procedures defined by the WPS used to weld a test coupon. It also contains the test results of the tested specimens. The PQR basically establishes that the weldments specified by the WPS are capable of providing the required properties for its intended application.

4.4 The Welder Performance Qualification (WPQ) documents the ability of the welder being tested to produce a weld using a specific set of materials, consumables, and procedures to meet certain quality requirements.

4.5 Supports or braces may not be welded directly to pipe that will be operated at a pressure of more than 100 PSIG.

4.6 A weld map and weld location record shall be completed.

4.7 All visual inspection and nondestructive testing shall be per Procedure 15.02.

4.8 The ground wire may not be welded to the pipe or fitting being welded.

5. QUALIFICATION OF WELDING PROCEDURES AND WELDERS

5.1 All welding performed on hazardous liquid pipeline systems shall be completed using welding procedures qualified in accordance with the Section 5 of API 1104 (19^{th} Edition) "Welding of Pipelines and Related Facilities" or Section IX "Welding and Brazing Qualifications" of the ASME Boiler and Pressure Vessel Code (49CFR 195 currently referenced edition).

5.2 Each welder shall be qualified in accordance with Section 6 of API Standard 1104 (19^{th} Edition) "Welding and Pipelines and Related Facilities" or Section IX "Welding and Brazing Qualifications" of the ASME Boiler and Pressure Vessel Code (49CFR 195 currently referenced edition).

5.2.1 No welder may weld with a particular welding process unless, within the preceding six calendar months, the welder has;

- Engaged in welding with that process, and
- Had one weld tested and found acceptable under Section 9 of API 1104 (49 CFR 195 currently referenced edition).

5.2.2 When there is specific reason to question the welder's ability to make welds that meet the specification, the WPQ qualification which supports the welding he is doing shall be retested. All other qualifications not questioned remain in effect.

5.3 Each contractor is responsible for the welding performed by their organization. They will conduct the tests required to qualify their welding procedures and each of their welders.

5.4 It is the contractor's responsibility to furnish the Company with complete copies of their welding procedure specification (WPS), procedure qualification record (PQR), and welding performance qualifications record (WPQ) for each welder, and any changes that occur thereto while working for the Company. The contractor is also responsible for retaining and maintaining complete documentation of same, and providing full access to Company as required.

6. PROCEDURE

6.1 Prior to the start of any welding, an appropriate weld procedure shall be selected and qualified, if not presently qualified.

6.2 Each welder must be qualified to weld by the selected procedure.

6.3 All production welding must conform to the requirements of design drawings or specifications, the selected qualified welding procedure specification (WPS), and within the limits of the welder's performance qualification (WPQ).

6.4 The welding operation must be protected from the weather conditions that would impair the quality of the completed weld.

6.5 Before beginning any welding,

6.5.1 The welding to be performed shall be evaluated for hazards which may affect the safety and health of personnel working in the area or the general public. Welding shall begin only when safe conditions are indicated.

6.5.1.1 A thorough check shall be made in or around a structure or area containing gas facilities to determine the possible presence of a combustible mixture.

6.5.1.2 Where welding is performed in a public area, a means to shield the public from welding arcs shall be provided between welding and public, or assure that public is not present during welding.

6.5.2 Welding surfaces must be free of defects such as laminations, cracks, dents, gouges, grooves, and notches.

6.5.3 Welding surfaces must be clean and free of any material that may be detrimental to the weld. Each joint of pipe may require swabbing to remove all dirt and foreign materials from the inside.

6.5.4 Bevels shall be checked for proper dimensions and angle.

6.5.5 Ensure that the longitudinal seams are offset. The seams should be located on the upper quadrant of the line and preferably within 30° of top center. Alternate joints shall be rotated to right or left at least 15° to avoid aligning the seams in adjacent joints. Exceptions to this requirement shall be made for making bends, as the longitudinal seam must remain on the neutral axis of the bend, and at other locations as may be indicated on the design drawings.

6.5.6 The line-up shall be checked to ensure proper root spacing and alignment. This alignment must be preserved while the root bead is being deposited.

6.5.7 Welding consumables shall be confirmed for correct type, proper use, control and handling prior to and during use. All welding rod stubs and discarded rods shall be gathered and disposed of in a manner and place authorized by the Company. No welding rod shall be left on or around the working area or deposited in the ditch.

6.6 Preheated and interpass temperatures shall be maintained within the specified ranges.

6.6.1 Preheating shall be required when the welding procedure indicates that chemical composition, ambient and/or metal temperature, material thickness, or weld-end geometry require such treatment to produce satisfactory welds.

6.6.2 The temperature shall be checked by the use of temperature-indicating crayons, thermocouple pyrometers, or other suitable methods to assure that the required preheat temperature is obtained prior to and maintained during the welding operation.

6.7 Grinding and cleaning of the stringer (root) bead shall be completed prior to depositing subsequent filler passes.

6.8 Welds in carbon steels having a high carbon content which require stress relieving by the applicable code (API 1104, 49CFR 195 currently referenced edition), shall be stress relieved as prescribed in ASME Boiler and Pressure Vessel Code, Section VIII. Stress relieving may also be advisable for welds in steel having lower carbon or carbon equivalent when adverse conditions exist which cool the weld too rapidly.

6.8.1 Welds in carbon steels shall be stress relieved when the wall thickness exceeds 1-1/4 in (3.81 cm).

Note: Above mentioned codes shall be the 49CFR 195 currently referenced editions.

6.9 Mark and ensure that all arc burns are removed and repaired. A ground may not be welded to the pipe or fitting that is being welded.

6.10 A miter joint is not permitted (not including defections up to 3° that are caused by misalignment). Any weld which is not at right angles to the axis of the pipe will be considered a mitered weld, unless the angle is specifically called for on the design drawings.

6.11 Weld numbers and welder identification numbers shall be applied using waterproof crayon, paint pens, or similar markers on the pipe coating adjacent to the weld for temporary identification. Marks shall be made on the top of the pipe approximately 1 foot (0.30 meters) from the cutbacks on the pipe coating, and shall be visible after joint coating is complete.

6.12 A permanent record in the form of weld maps shall be made indicating the location of all welds that can be cross referenced to the weld's nondestructive testing and to the welder making the weld. Also, a record of the total number of girth welds and the number nondestructively tested, including the number of rejected and the disposition of each rejected weld will be maintained.

7. REPAIR OR REMOVAL OF WELD DEFECTS

7.1 Qualified procedures and currently qualified welders are required for all repair work.

7.2 Each weld that is found unacceptable must be removed or repaired. Except for welds on an offshore pipeline being installed from a pipelay vessel, a weld must be completely removed if it has a crack that is more than 8 percent of the weld length.

7.3 Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability.

7.4 The repair of a crack in a weld, providing it does not exceed 8% of the weld length, or, of any defect or flaw in a previously repaired weld, must be according to a written weld procedure qualified under Section 5.0 of this procedure "Qualification of welding procedures and welders". The welder(s) must have qualified to the repair procedures prior to affecting the repair.

The repair procedure must provide that the repaired defect(s) equal or exceed the original mechanical properties of the originally intended weld.

Re-repair of welds will not be permitted unless approved by the District Engineer.

After any repair or re-repair, the weld must be non-destructively tested by any process to determine and ensure the repair's integrity. Please refer to Procedures 15.02 "Visual Inspection and Nondestructive Testing".

7.5 An arc burn can be caused by any means, whether by welding or other, can be injurious to the carrier pipe and is totally unacceptable. Arc burn affects the integrity of the pipe and can cause mechanical deficiencies and possible stress concentrations. Verify removal of arc burn (metallurgical notch) by non destructive testing (ammonium per sulfate).

An arc burn can be completely removed by grinding. However, the grinding process must not be excessive and to the point where the wall thickness is less than the minimum thickness required by the tolerances in the original specification of the pipe.

If the arc burn cannot be completely removed by grinding, a cylinder of the pipe containing the defect must be removed.

If grinding provides a thinner pipe wall than originally manufactured, and the pipe is to be retained, de-rating of the pipe must be considered.

8. RELATED PROCEDURES

9.01 Pipeline Repair Procedures
15.02 Visual Inspection and Nondestructive Testing

9. RECORDS

9.1 Insert copies of the welding procedures used, the location of the welds, the welders used, and the results of all nondestructive testing in the pipeline historical file.

9.2 Insert copies of pipe and fitting material qualifications, as-built drawings, and hydrostatic test records in the pipeline historical file.

9.3 These records are to be retained for the life of the facility.

CPF 5-2008-5034M
Line 3

VISUAL INSPECTION AND NON-DESTRUCTIVE TESTING

1. REFERENCE

49 CFR, Sections 195.212(c), 195.228, and 195.234. API Standard 1104 Section 9 (19th Edition)

2. PURPOSE

To establish minimum requirements for visual inspection and nondestructive testing of field made butt welds in piping to be operated under pressure.

3. RESPONSIBILITY FOR IMPLEMENTATION

The (351) _______________ is responsible for implementation of the requirements of this procedure.

4. GENERAL

4.1 All visual inspection and nondestructive testing of field made butt welds in hazardous liquid piping shall be in accordance with the DOT referenced edition, API Standard 1104 "Welding of Pipelines and Related Facilities" (49 CFR 195 currently referenced edition).

4.2 Radiographic inspection or ultrasonic inspection shall be used to satisfy the requirements for nondestructive testing of field made girth welds.

4.3 Persons nondestructively testing welds shall be trained and qualified to a Level II status in order to perform tests and interpret results in the testing method employed, per written nondestructive testing procedures, and be familiar with all requirements of the currently referenced edition of API Standard 1104.

4.4 The acceptability of a weld that is nondestructively tested or visually inspected, is determined according to the standards in Section 9 of API Standard 1104 (19th Edition) and 49 CFR 195.288 (currently referenced edition).

4.4.1 If a girth weld is unacceptable under those standards for a reason other than a crack, and if the Appendix to API Standard 1104 applies to the weld, the acceptability of the weld may be further determined under that Appendix.

4.5 Welding Inspector shall be qualified to perform visual weld inspection.

5. WELD NONDESTRUCTIVE TESTING

5.1 Any process, other than trepanning, that will clearly indicate defects that may affect the integrity of the weld, must perform nondestructive testing of welds.

5.2 Each weld that is found unacceptable must be removed or repaired, and then found acceptable. Except for welds on an offshore pipeline being installed from a pipe laying vessel, a weld must be completely removed if it has a crack that is more than 8% of the weld length.

5.3 Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair.

5.4 After repair, the segment of the weld that was repaired must be inspected to insure its acceptability.

5.5 Ensure the interpretations of all nondestructive test results by Nondestructive Testing Contractor are correct.

5.6 Follow the schedule in table 15.02 of this procedure for the minimum percentage of each day's field butt welds to be nondestructively tested over entire circumference.

5.7 At least 10% of each welder's daily welds, during construction, will be nondestructively tested over the entire circumference of the weld.

6. WELD VISUAL INSPECTION

6.1 Each weld and welding of a regulated pipeline shall be visually inspected by a qualified inspector to insure that:

6.1.1 The welding is performed in accordance with the welding procedures;

6.1.2 The welds are acceptable to the standards in Section 6 of API Std 1104, (49CFR 195 currently referenced edition).

6.1.3 The welds conform to the requirements of "Pipeline Welding" Procedure 9.06 and this "Visual Inspection and Nondestructive Testing" Procedure.

6.2 Ensure that each joint of pipe is inspected for defects such as laminations, cracks, dents, gouges, grooves, and notches.

6.3 Bevels shall be inspected for proper dimensions, cleanliness and angle.

6.4 Ensure that each joint of pipe is swabbed as necessary to remove all dirt and foreign materials from the inside.

6.5 Ensure that the longitudinal seams are offset as stated in Procedure 9.06. The line up shall be inspected to ensure proper root spacing and alignment.

6.6 The stringer (root) bead shall be inspected for proper grinding and cleaning.

6.7 If more than one grade or weight of pipe or fittings are used, ensure that it is according to the approved construction drawings.

6.8 Mark and ensure that all arc burns are removed and repaired according to Procedure 9.06.

7. RELATED PROCEDURES

9.06 Pipeline Welding
15.01 Pressure Testing

8. RECORDS

8.1 Develop a record keeping system for location of non-destructive tested welds on stations (i.e., compressor stations, meter stations, etc.) piping to ensure that girth welds on pressurized piping have been nondestructively tested in the correct amount (show in station piping drawings).

8.2 Record to show by milepost, station plus, or by geographic feature, the location of girth welds made, the number of nondestructively tested, the number rejected, and the disposition of the rejects. (Show on alignment sheets).

8.3 Retain the above records for the life of the pipeline system.

8.4 Record results from radiograph films and ultrasonic testing with a unique numbering system allowing identification of the radiograph film or ultrasonic testing results to its respective weld.

8.5 Radiographic film must be retained for at least one year. However, as indicated above, the certification sheets and other records showing the disposition of the welds must be retained for the life of the pipeline.

TABLE 15.02
MINIMUM VISUAL INSPECTION & NONDESTRUCTIVE TESTING REQUIREMENTS FOR PRESSURIZED PIPING

Pipeline Locations	Visual Inspection	Non-Destructive Testing
Any Offshore Area	100%	100%(2)
Stream, River, Lake, Reservoir, or other body of Water (3)	100%	100%(2)
Railroads or Public Road Rights-of-Way (4)	100%	100%(2)
Road Crossings and Tunnels (5)	100%	100%(2)
Incorporated Subdivision of a State Government (6)	100%	100%(2)
Populated Areas (7)	100%	100%(2)
Used Pipe (8)	100%	100%
Tie-in's (9)	100%	100%
Pipe Bends (10)	100%	100%
Repaired Welds (11)	100%	100%(2)
Other Locations	100%	10%(1)

NOTES:

1. At least 10% of the girth welds made by each welder, during each welding day, must be nondestructively tested over the entire circumference of the weld.
2. All girth welds installed each day must be nondestructively tested over the entire circumference of the weld unless impracticable, in which case 90% must be tested (i.e., nondestructive testing must be impracticable for each girth weld not tested).
3. At any onshore location where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water.
4. Within railroad or public road rights-of-way.
5. At overhead road crossings and within tunnels.
6. Within the limits of any incorporated subdivision of a State government.
7. Within populated areas, including, but not limited to, residential subdivisions, shopping centers, schools, designated commercial areas, industrial facilities, public institutions, and places of public assembly.
8. When installing used pipe, 100% of the old girth welds must be nondestructively tested.

9. At pipeline tie-ins, including tie-ins of replacement sections, 100% of the girth welds must be nondestructively tested.
10. Each circumferential weld, which is located where the stress during bending causes a permanent deformation in the pipe, must be nondestructively tested either before or after the bending process.
11. Welds repaired due to nondestructive testing rejection, must be re-tested over the entire weld length.
12. Inspection of repaired welds must be performed using the method of inspection used to identify original defect.

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF AMENDMENT

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

November 14, 2008

Mr. Robert Pyle
Manager, Pipeline and Marine Logistics
Pacific Energy Resources, Ltd.
111 West Ocean Blvd., Suite 1240
Long Beach, CA 90802

CPF 5-2008-7002M

Dear Mr. Pyle:

On May 19-22, 2008, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the California State Fire Marshal (CSFM), pursuant to Chapter 601 of 49 United States Code, inspected Pacific Energy Resources, Ltd.'s (PERL) procedures and supporting implementation records for their Integrity Management Program (IMP) in Long Beach, California.

On the basis of the inspection, PHMSA has identified the apparent inadequacies found within PERL's plans or procedures, as described below:

1. **§195.452 Pipeline integrity management in high consequence areas**

    (f) 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).

The PERL procedures are inadequate for ensuring the qualification of the IMP reviewers and evaluators. Currently, the procedures require documentation of the IMP team members; however, the procedures do not specify the level of qualifications the IMP reviewers must have to adequately review and analyze the assessment results.

2. **§195.452 Pipeline integrity management *in* high consequence areas**

(f) 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);
(h) 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.

The PERL procedures do not specify what the in-line inspection (ILI) vendors' qualifications must be. The PERL procedures do not ensure through contractual means or otherwise, that their ILI tool vendor performs integrity assessments and information analysis in accordance with Part 195.452(f) (4).

3. **§195.452 Pipeline integrity management in high consequence areas**

(h) What actions must an operator take to address integrity issues?
(1) General requirements. An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with § 195.422 when making a repair.
(i) *Temporary pressure reduction*. An operator must notify PHMSA, in accordance with paragraph (m) of this section, if the operator cannot meet the schedule for evaluation and remediation required under paragraph (h)(3) of this section and cannot provide safety through a temporary reduction in operating pressure.
(ii) Long-term pressure reduction. When a pressure reduction exceeds 365 days, the operator must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. An operator must also take further remedial action to ensure the safety of the pipeline.
(3) Schedule for evaluation and remediation. An operator must complete remediation of a condition according to a schedule that prioritizes the conditions for evaluation and remediation. If an operator cannot meet the schedule for any condition, the operator must justify the reasons why it cannot meet the schedule

and that the changed schedule will not jeopardize public safety or environmental protection. An operator must notify OPS if the operator cannot meet the schedule and can not provide safety through a temporary reduction in operating pressure. An operator must send the notice to the address specified in paragraph (m) of this section.
(m) Where does an operator send a notification? An operator must send any notification required by this section to the Information Resources Manager, Office of Pipeline Safety, Research and Special Programs Administration, U.S. Department of Transportation, Room 7128, 400 Seventh Street SW, Washington DC 20590, or to the facsimile number (202) 366-7128.

The PERL IMP procedures do not ensure the operator cannot exceed 365 days without making a formal notification to the PHMSA. The procedures also do not specify what additional safety measures will be used to ensure long term safety.

4. **§195.452 Pipeline integrity management in high consequence areas**

(e) 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:
(i) What preventive and mitigative measures must an operator take to protect the high consequence area?
(2) Risk analysis criteria. In identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect the high consequence area. This determination must consider all relevant risk factors, including, but not limited to:

The PERL procedures do not consider the risks associated with alternate modes of operation of their pipelines, e.g. startup, shutdown, shut-in, slack line, pressure cycling, etc. In addition, the PERL procedures do not consider likely risk factors and threats on their pipeline, e.g. the risk for corrosion needs to be more threat specific for each type of condition or environment.

5. **§195.452 Pipeline integrity management in high consequence areas**

(f) An operator must include, at minimum, each of the following elements in its written integrity management program:
(7) Methods to measure the program's effectiveness (see paragraph (k) of this section)

(k) An operator's program must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas. See Appendix C of this part for guidance on methods that can be used to evaluate a program's effectiveness.

PERL's root cause analysis was not adequately integrated into their IM program. The analysis currently used by the PERL is not referenced in its IMP to ensure a process for an effective root cause analysis and lessons learned.

6. **§195.452 Pipeline integrity management in high consequence areas**

(l) What records must be kept?
(1) An operator must maintain for review during an inspection:
(i) A written integrity management program in accordance with paragraph (b) of this section.
(ii) Documents to support the decisions and analyses, including any modifications, justifications, variances, deviations and determinations made, and actions taken, to implement and evaluate each element of the integrity management program listed in paragraph (f) of this section.
(2) See Appendix C of this part for examples of records an operator would be required to keep.

The PERL IMP procedures do not include a document retention policy that ensures key documents, as described in Part §195.452 (l), are retained for the life of the pipeline.

Response to this Notice

This Notice is provided pursuant to 49 U.S.C. § 60108(a) and 49 C.F.R. § 190.237. Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

If, after opportunity for a hearing, your plans or procedures are found inadequate as alleged in this Notice, you may be ordered to amend your plans or procedures to correct the inadequacies (49 C.F.R. § 190.237). If you are not contesting this Notice, we propose that you submit your amended procedures to my office within 60 days of receipt of this Notice. This period may be extended by written request for good cause. Once the inadequacies identified herein have been addressed in your amended procedures, this enforcement action will be closed.

In correspondence concerning this matter, please refer to **CPF 5-2008-7002M** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 H. Monfared (#120746)

Enclosure: *Response Options for Pipeline Operators in Compliance Proceedings*

CPF 5-2008-7002M
Line 1

RICHARD ARMSTRONG
DOT INTEGRITY MANAGEMENT PLAN RESUME

OBJECTIVE

This resume is a document to show Richard Armstrong's qualification to participate in the DOT Integrity Management Plan process.

RELEVANT SKILLS

PIPELINE, ENVIRONMENTAL & SAFETY

- DOT Pipeline Operations and Compliance Specialist.
- Develop, coordinate and perform pipeline projects, maintenance programs.
- Coordinator for San Pedro Bay Pipeline Leak Detection System Installation and Training.
- Pipeline Group Member of the initial Development of the DOT Hazardous Liquids IMP Manual.
- Pipeline loss and gains accounting.
- OQ Coordinator and trained evaluator for Beta in DOT OQ requirement.
- Procedure development and training for pipeline operations on and offshore. Developed O&M manual procedures for San Pedro Bay Pipeline

TRAINING SCHOOLS & CERTIFICATES

- Certified under DOT Operator Qualification rule from Midwest Energy Associations (MEA) "OQ For All" training program as a qualified operator.
- Certified DOT OQ Evaluator by Midwest Energy Association (MEA) evaluator training program.
- Completed course "Cathodic Protection Best Practices" by Farwest Corrosion.
- Science Applications International Corp. Annual OPA 90 Training - Certificate
- International School of Hydrocarbon Measurement (ISHM) - Certificate's
- TNT Environmental Services. Hazardous Emergency Action Training - Certificate
- California Specialized Training institute - First Responder Operational - Certificate
- Powerine Oil Company - Hazwoper training

EMPLOYMENT HISTORY

2007 – Present	Pacific Energy Resources Ltd.	Long Beach, Ca
2005 – 2007	Aera Energy LLC DOT Operations, LA Basin	Long Beach, Ca
1997 – 2005	BPM LLC Contracted to Aera Energy LLC Pipeline Maintenance & Operations Supervisor	Signal Hill, Ca
1990 - 1997	Powerine Oil Company Division D (DOT Operations) Team leader	Santa Fe Springs, Ca
1982 – 1990	Santa Fe Pipelines Pipeline Operations	Orange, Ca

EDUCATION

AA Business Administration	Chaffey Community College	1981-82

REV 1-09 RA

ANDY BRADFIELD

Compliance Services Inc

PO Box 22410
Bakersfield, Ca. 93390
(661) 549-8518

SUMMARY OF QUALIFICATIONS

- Eighteen years in oil production industry as an electrician, operations supervisor, and environmental/safety compliance advisor.
- Motivated and enthusiastic about continuous self development.
- Effective working alone or as a cooperative team member.
- Professional in appearance and presentation.

RELEVANT SKILLS

ENVIRONMENTAL/SAFETY

- Compliance auditing of all safety and environmental regulations.
- Compliance audits of over twelve DOT jurisdictional pipeline systems, including audits in the following states: California (DOT, CSFM, & CPUC), Arizona, Oregon, and Washington
- Compliance training and operator qualification of pipeline personnel.
- Experienced in customer relations, negotiations, and training.
- Writing compliance manuals for pipeline systems including O&M Manuals, Emergency Response Manuals, Operator Qualification Plans, and Integrity Management Plans.

TRAINING

- Computer skills in MS Word, Excel, Access, MS Outlook.
- Supervisory skills in time management, goal setting, negotiating.
- Training certificates in DOT Pipelines, DOT Transportation, Hazwoper, and Langevin Train-The-Trainer

EMPLOYMENT HISTORY

2000-present	Owner/Consultant	Compliance Services Inc
1999 - 2000	Manager, Regulatory Compliance	Dick Brown Tech Service Rio Vista, Ca.
1989 - 1999	Environmental/Safety Advisor	Shell Oil/Aera Energy Bakersfield, Ca.
1984 – 1989	Operations Supervisor	Shell Oil Bakersfield, Ca.
1981 – 1984	Offshore Maintenance Electrician	Shell Oil Bakersfield, Ca.
1975 – 1981	Electrician/Nuclear Power Operator	U. S. Navy USA

EDUCATION

Buena High School, Ventura, Ca., 1974
Bakersfield College, Associate of Science in Hazardous Materials Tech., 1990-1993
Currently enrolled at Cal State Bakersfield, Environmental Resource Management

ROBERT PYLE
DOT INTEGRITY MANAGEMENT PLAN RESUME

OBJECTIVE

This resume is a document to show the qualifications of ROBERT PYLE to participate in the DOT Integrity Management Plan process.

RELEVANT SKILLS

PIPELINE, ENVIRONMENTAL & SAFETY

-----Hazardous Material Removal Endorsement, State of California
-----Pipeline Safety Institute, LLC Hazardous Liquids Course
-----API RP T-2 School Operator, Certification Course for Offshore Workers
-----Refinery Safety Training Arco, Texaco, Mobil, Shell and Chevron
-----Logistics Support Platform Edith

TRAINING SCHOOLS & CERTIFICATES

----Class A General Engineering License, State of California
---Hazwoper – Rust Industrial Services
----Licensed Commercial Pilot, Multi Engine Piston
---US Navy Deep Sea Diving and Salvage School, 22nd St., San Diego, California
---**Underwater ship husbandry, US Navy, Coatings, CP Systems, Repairs, San Diego, CA**
---**A, B, C, School US Navy Mark 84 Weapons System, Dam-neck, VA**
---- **US Navy Submarine School Groton, Connecticut, 9-SS/SSBN Dv FTB-1**

EMPLOYMENT HISTORY

2006--- 2007	Pacific Energy Resources, Ltd.	Long Beach,	CA
1993----2006	HydroGuard. Inc (President)	Long Beach,	CA
1990----1993	Rust Industrial Services, Inc.	Long Beach,	CA
1988----1990	LB Associates (President)	Long Beach,	CA
1984----1988	EnviroGuard, Inc. (President)	Houston,	TX
1978----1984	Western Equipment, Inc. (President)	Long Beach,	CA
1971----1978	RMP Marine, Inc. (President)	Long Beach,	CA
1969----1971	Brown & Root Taylor Diving & Salvage	Manama,	Bahrain
1962----1969	US Navy Polaris Program	Honolulu,	Hawaii

EDUCATION

University of Hawaii, US Navy Man in The Sea Program, Marine Science

DIVERSIFIED PROJECT SERVICES INTERNATIONAL

Robert J. Chambers, P.E.
President

Background

Mr. Chambers has over 20 years of experience in management of engineering and construction projects in the petroleum and power industries. He has managed multidisciplinary engineering offices with staffs of up to 20 mechanical and civil engineers and land surveyors. He has worked as an engineering and construction manager, senior project manager, senior estimator, and project management consultant. Mr. Chambers started DPSI in 2007 to serve clients in the energy industry.

Education

Bachelor of Science in Mechanical Engineering, California Polytechnic State University, San Luis Obispo, California

Professional Registration

Licensed Mechanical Engineer #M31647, State of California

Affiliations

Society of Petroleum Engineers
American Society of Mechanical Engineers
Cal Poly Mechanical Engineering Energy Institute
Speakers Bureau, City of Bakersfield Chamber of Commerce Energy Committee

PROJECT HISTORY AND EXPERIENCE

Platform Eureka Return to Production

Pacific Energy Resources returned one offshore platform, Eureka, to production after being idle for nine years. It is now in operation with a capacity to produce up to 5,000 barrels of crude oil per day. Mr. Chambers was the overall project manager for this project. Tasks included management of permitting/agency coordination, budget development and securing of funding, and management of all engineering disciplines and construction activities.

Long Term Energy and Dehydration System Studies, BETA Offshore Complex

Aera Energy required various studies relating to their three-platform BETA production complex. The complex includes two production platforms and one processing platform. Mr. Chambers was the project manager for several of these studies. A long-term energy study was performed to compare various methods for providing supplemental energy to the offshore production complex. Additional energy was required due to increased water and decreased gas production. A separate study was performed to evaluate options to improve the efficiency and capacity of BETA's dehydration system. Projects included analysis and coordination of federal, state and local permitting activities.

Commercial Demonstration Facility, Kern County, California

A Rapid Thermal Processing demonstration facility was recently constructed in the South Belridge oil field. The facility converts heavy crude oil to light, and generates excess heat useable for thermal recovery. This new technology is currently being tested on crude oil from different sources throughout the world. The two acre facility includes industrial structures over seventy feet in height, and was constructed twelve miles from the San Andreas Fault. Mr. Chambers managed the design, coordinated permitting, bid package preparation, and assisted with contractor selection.

Project Management Consulting, Bakersfield, California
Mr. Chambers coordinated a Project Management Advisory Team for Aera Energy, which at the time was the largest oil producing company in California. Mr. Chambers was invited to join the team to provide third-party expertise in the development and implementation of standard cost and scope management processes. Mr. Chambers also conducted an 8-hour project management training course for Aera's project staff, and performed periodic audits to assess each project team's level of compliance using the standard processes. The processes are now being used on all capital projects (up to $300,000,000/yr).

Submarine Outfall Line Replacement, Santa Maria, California
The submarine outfall line replacement for Union Oil Company of California involved the assembly of 2500 feet of 14-inch concrete weight-coated pipe on the Pismo Dunes, which was then pulled into the ocean by a barge anchored offshore. Mr. Chambers was the construction estimator and project manager for the replacement project.

Fire Rebuild Projects, Wilmington, California
As the construction project manager for the Alkylation unit and HTU4 Unit fire rebuild projects at Texaco's Los Angeles Refinery, Mr. Chambers managed up to eighty craftsmen working 24 hours per day. Crafts included pipe fitters, ironworkers, and instrumentation and controls technicians. The projects consisted of structural steel, piping, mechanical equipment, and process vessel replacement and modifications. The projects were completed on a fast track schedule to return the units to operation.

Electrical Power Generation Project, Santa Maria, California
During the overall construction of a 6.2 Megawatt power generation facility within an operating refinery, Mr. Chambers served as estimator and construction project manager. The facility was constructed on a fast track schedule, and consisted of a variety of vessels, boiler, steam turbine generator, condenser, substation, and ancillary systems. Mr. Chambers was responsible for supervision of all craft labor and coordination of construction activities.

API 14C Compliance Program, BETA Offshore Production Complex, California
Aera Energy required assistance to determine the level of compliance of three of their platforms with the safety requirements listed in API Recommended Practices 14C. Mr. Chambers was responsible for managing the project. A report was prepared which summarized deficiencies and included recommended corrective actions. Mr. Chambers then managed the implementation of all of the corrective actions and updated the documentation for presentation to state and federal agencies.

Fuel Cell Product Development Test Project, Miramar Naval Air Station, San Diego, California
The Fuel Cell Product Development Test Project for San Diego Gas and Electric and the Department of Energy involved construction of a 250 kW demonstration plant utilizing molten carbonate electrolyte technology. Mr. Chambers was the project manager and estimator.

Former Guadalupe Oil Field, Guadalupe Dunes, California
From July 1998 to September 1999, Mr. Chambers served as the engineering and construction project manager over engineering and construction of active recovery systems and excavations required to clean up approximately 18 million gallons of underground petroleum contamination.

Common Turn-Around Construction Projects, Santa Maria, California
During shutdown of this refinery, Mr. Chambers was responsible for a number of associated projects including installation of piping systems, rotating equipment, structural concrete, vessels, and associated systems. This work was completed on a 24/7 schedule and included all equipment procurement, direction of contractors, and commissioning supervision.

3-MGD Water Treatment Plant, Los Angeles, California
As project manager for this Department of Water and Power water treatment plant, Mr. Chambers was responsible for preparing the scope of work for mechanical, electrical, structural, civil, instrumentation, and all other disciplines associated with the construction of the plant. He directed the project staff and coordinated all construction and field engineering. Mr. Chambers was responsible for obtaining permits, agency approvals, and maintaining a good owner-client relationship.

Wastewater Treatment Plant Expansion, Carson, California
During the expansion of Arco's Wastewater Treatment Plant in Carson, Mr. Chambers served as the project manager and estimator for the expansion of Trap Numbers 3 and 4. The project consisted of the installation of a wide variety of basins, tankage, piping, and transfer pumps. The project was completed on a fast track schedule, with Mr. Chambers responsible for the coordination of all equipment, deliveries, and construction contractors.

Water Conservation System, Santa Maria, California
A turnkey Water Conservation System was established to reduce overall refinery consumption of industrial water. Mr. Chambers was the project manager and estimator for the project which consisted of the installation of process equipment including filtration and storage equipment, interconnect piping systems, and ancillary equipment.

Deisobutanizer Upgrade, Elk Hills, California
Bechtel Petroleum Operations performed an upgrade of the deisobutanizer system and installation of a firewater system at their Naval Petroleum Reserve. The project involved the installation of a variety of pressure vessels, rotating equipment, structural concrete, pipe supports, interconnecting piping, and instrumentation. Mr. Chambers was the project manager and estimator for the improvements.

Dehy Conversion Project, Bakersfield, California
Following construction of the $12 million South Belridge Dehy 20 Conversion project, Mr. Chambers performed an independent post-construction review including analysis of project planning, estimating, engineering, procurement, construction and accounting. The final report and recommendations were presented to Aera Energy's CEO.

BRIEN VIERRA
Mechanical Engineer

Professional Registration
- Mechanical Engineer, California, Certificate No. 32330

Education
- Bachelor of Science, Mechanical Engineering Technology
  California Polytechnic State University, San Luis Obispo, California
- Fire Protection Training Academy
- University of Nevada, Reno
- Hazard Analysis Training Course
- HAZMAT 40-Hour Training Certification Course
- Storm Water Regulations, Erosion and Sediment Control Training Class, RWQCB - 2000
- Threatened and Endangered Species Preliminary Survey Protocols Training Class, LFR 1999

Professional Affiliations
- Society of Manufacturing Engineers

Experience Summary

Mr. Vierra has over 17 years of field experience in the petroleum industry performing in several capacities. His experience includes a diverse area such as; permitting and design of cross country pipelines, permitting and design of pipeline replacements, field construction monitoring (for compliance and per specification), project management, project design, hydraulic analysis, pipe stress analysis, risk analysis, tank and pipeline internal/external inspection analysis, preparation of weld procedures and conceptual planning. Permitting requirements vary from simple plot plans to coordinating with multi jurisdictional agencies such as DFG, Army Corp, RWQCB, MMS, ADEC and various counties/parishes as well as coordinating with various professional individuals for specialized field studies/reports.

Representative Experience

Pipeline Repair/Replacement Project - Alaska

Provide engineering design, project management and hydraulic analysis to retrofit existing 30-inch tanker loading lines for internally inspecting the two lines. The project involved revising the existing onshore piping and platform piping. The onshore piping required a new pig trap design with the offshore piping requiring extensive piping modifications to allow temporary pipe spools to be installed. A review and analysis of the internal inspection report was performed, then recommendations for further investigation/repairs were provided.

Experience (cont)

Pipeline Close Interval Survey - Alaska

Perform close interval survey (pipe to soil) for 41.5 miles of 20-inch pipeline and 2.5 miles of 12-inch pipe. Survey included providing a written report discussing potential areas of concern with graphical printout of survey.

Relocation of two 8-Inch Pipelines Across Highway 101 - California

This project involved installing two directional drilled casings under Highway 101 as well as the nearby creek. Mr. Vierra provided engineering and permitting services to facilitate the construction of the pipeline replacement. Permitting services included Caltrans Encroachment permit, San Luis Obispo County Encroachment permit, DFG Streambed Alteration Permit, Army Corp. of Engineer Permit and RWQCB Permit.

23 mile Pipeline and Facility Design Project - Louisiana

Involved the planning, engineering, installation and operation of 23 miles of 6" pipe to transport crude oil from Offshore Louisiana to tie-in with an existing pipe system. Project included facility design, three directionally drilled crossings, offshore pipelaying in approximately 45 feet of water, inshore pipelaying through marsh and tying in pipeline to existing system. Responsibilities included complete project management, environmental compliance, material acquisition, contracts, permitting, acquisition of right of way, overall final design, training of personnel for operations and startup troubleshooting. Total overall cost of the project was approximately $7.5 MM.

10.2 mile Pipeline Project with High Pressure Meter Stations and Facilities - California

Project involved preparing and submitting permit requests to Santa Barbara County and various other agencies. Overseeing the planning, engineering, environmental review of the project with various consultants and field construction. Writing of several manuals for Operations, Emergency Response, Oil Spill Response, Environmental Manuals, Etc.. Designated on-site engineer during construction and startup. Total overall cost of the project was approximately $7.2 MM.

20-inch Pipeline Replacement Project – Alaska

This project involved installing approximately 1800 feet of 20-inch pipe via a directional drilled crossing under a river where the old pipe had been damaged. Mr. Vierra provided preliminary engineering, directional drill layout and permitting services as well as construction support during the installation of the pipe replacement. Once the project was complete as-built drawings were provided to the client.

Crude & Product Storage Tank Retrofits – Alaska, California, Illinois, Louisiana, and Texas

Projects performed involved preparing specifications for cleaning, coating, installing double bottoms, and performing API 653 inspections. Additional work to complete tank repairs involved preparation of procedures to repair tank floors, *Experience (cont)*

replace nozzles not in compliance with API 650/653 and verification of weld procedures.

1.2-mile Transmission Line Renewal - California:

Mr. Vierra was the project manager responsible for overseeing this 1.2-mile, 12-inch steel oil transmission line renewal through the main business district of a beach community. He prepared preliminary hydraulic calculations, as well as hired and managed outside engineering, environmental and risk analysis consultants. Mr. Vierra worked with consultants and agencies to obtain permits and agency approvals from the City, Department of Fish and Game, and the Regional Water Quality Control Board. Construction costs on the project were approximately $1 million.

3.5-mile Transmission Line Replacement - California:

Mr. Vierra was the project manager responsible for overseeing the replacement of a 3.5-mile section of two, 8 inch-steel oil transmission lines located near the town of Santa Margarita. These lines were located adjacent to a perennial stream and crossed it in four locations. Each of these crossings required permit approval by the Army Corps of Engineers, RWQCB and the Department of Fish and Game. The project involved preparing engineering packages, environmental documents (archaeological and biological), permit packages, field monitoring for compliance and updating of response plans. Construction costs on the project were approximately $1.5 million.

Heating, Separating & Pumping Facility Retrofit and Upgrade - California

Install new 8.9 MM BTU Burners in existing heater treaters for compliance with new NOx and SOx emission requirements. Source test equipment and demonstrate compliance with regulating agency. Work involved replacing heat exchanger's with updated more efficient models. Install new water shipping pumps capable of handling higher flow rates and injection pressures.

Crude and Product Pipeline Installation, Operation and Relocation Work – Alaska, California, Illinois, Louisiana, and Texas

Work involved modifying existing operations, troubleshooting mechanical/electrical problems, pipeline tie-ins, writing of procedures, compliance plans, directional drilling plans, response plans and project specifications. Field engineering and installation of various pieces of equipment. Hydrotesting of lines for DOT and State Fire Marshall compliance. Running of internal inspection tools on various pipeline's to determine remaining wall thickness and operational safety of the entire system.

Corrosion Control and Repair of CP System at VAFB

Mr. Vierra reviewed site data and prepared design drawings/specifications/cost benefit analysis to repair an existing cathodic protection system as well as control existing surface corrosion on various pieces of equipment subject to a harsh environment.

Shane Manning – Career Highlights

- Mr. Shane Manning graduated with degrees from The University of Western Ontario with a Bachelor of Engineering Science in Mechanical Engineering in 1996 and a Bachelor of Social Science in Economics in 1997.
- He has spent his career working in both the Oil & Gas business and Automotive Design. While working in Automotive Design, Mr. Manning designed and engineered hinge systems for a *variety of production vehicles for Ford Motor Company and solely developed some unique* designs that were patented and are currently used on Ford vehicles.
- While working in Oil & Gas in Iran, Mr. Manning contributed to the success of Canadian Triton International (CTI), a Canadian company that increased Iran's oil production by 350,000 barrels of oil per day using horizontal drilling techniques. Many of the responsibilities included constant monitoring of drilling equipment and supervision of employees.
- In 2001, Mr. Manning co-founded Katman Petroleum LLC and served as the company Director and President. Katman Petroleum LLC merged with its partners to form Pacific Energy Resources, Ltd where Mr. Manning is currently employed.

PACIFIC ENERGY RESOURCES
Hazardous Liquid Integrity Management Program
IMP Team Members
Standards, Training, and Qualification

Ref: 49 CFR 195.452(j) **Updated: March 2008**

#	Name:	Title:	Company:	Brief Description of Core Functions:
1.	Rick Armstrong	DOT Specialists	Pacific Energy	IMP Team Leader ▪ IMP program implementation ▪ HCA analysis ▪ Risk assessment • ILI data review
2.	Bob Pyle	Manager, Pipeline & Marine Logistics	Pacific Energy	IMP program support ▪ IMP program implementation ▪ HCA analysis ▪ Risk assessment • ILI data review • Engineering
3	Shane Manning	Facilities Engineer	Pacific Energy	IMP program support ▪ IMP program implementation ▪ HCA analysis ▪ Risk assessment • ILI data review • Engineering
4	Andy Bradfield	IMP consultant	Compliance Services Inc	Support IMP team leader ▪ Provide guidance and support on IMP requirements
5	Robert Chambers	Engineering Consultant	Diversified Project Services International, Inc.	ILI data review Pipeline repairs
6	Brien Vierra	Engineering Consultant	Cannon and Associates	ILI data review Pipeline repairs Corrosion evaluation

Pacific Energy Resources LIQUID IMP TEAM MEMBERS

Updated: March 24, 2008

HCA Segment Name	IMP Consultant	Required Qualifications	IMP Team Leader	Required Qualifications	Pipeline Manager	Required Qualifications	Pipeline Engineer	Required Qualifications
Elly Riser	Andy Bradfield, Compliance Services Inc	>5 years oil field experience and science degree. Minimum 2 years experience in pipeline integrity issues or equivalent.	Rick Armstrong DOT Specialist	>5 years of experience in Oil Field and DOT Pipeline operations. Minimum 5 years experience in pipeline integrity and compliance issues or equivalent.	Bob Pyle, Manager, Pipeline and Marine Logistics	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation.	Robert Chambers, Brent Vierra, Pipeline Engineering Consultants. Shane Manning Pac Energy Facility Engineer	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation. Science and Engineering degree.
EllySubsea	Andy Bradfield, Compliance Services Inc	>5 years oil field experience and science degree. Minimum 2 years experience in pipeline integrity issues or equivalent.	Rick Armstrong DOT Specialist	>5 years of experience in Oil Field and DOT Pipeline operations. Minimum 5 years experience in pipeline integrity and compliance issues or equivalent.	Bob Pyle, Manager, Pipeline and Marine Logistics	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation.	Robert Chambers, Brent Vierra, Pipeline Engineering Consultants. Shane Manning Pac Energy Facility Engineer	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation. Science and Engineering degree.
Elly Onshore	Andy Bradfield, Compliance Services Inc	>5 years oil field experience and science degree. Minimum 2 years experience in pipeline integrity issues or equivalent.	Rick Armstrong DOT Specialist	>5 years of experience in Oil Field and DOT Pipeline operations. Minimum 5 years experience in pipeline integrity and compliance issues or equivalent.	Bob Pyle, Manager, Pipeline and Marine Logistics	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation	Robert Chambers, Brein Vierra, Pipeline Engineering Consultants. Shane Manning Pac Energy Facility Engineer	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation. Science and Engineering degree.
Beta Station	Andy Bradfield, Compliance Services Inc	>5 years oil field experience and science degree. Minimum 2 years experience in pipeline integrity issues or equivalent.	Rick Armstrong DOT Specialist	>5 years of experience in Oil Field and DOT Pipeline operations. Minimum 5 years experience in pipeline integrity and compliance issues or equivalent.	Bob Pyle, Manager, Pipeline and Marine Logistics	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation.	Robert Chambers, Brein Vierra, Pipeline Engineering Consultants. Shane Manning Pac Energy Facility Engineer	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation. Science and Engineering degree.
Delivery Line #1	Andy Bradfield, Compliance Services Inc	>5 years oil field experience and science degree. Minimum 2 years experience in pipeline integrity issues or equivalent.	Rick Armstrong DOT Specialist	>5 years of experience in Oil Field and DOT Pipeline operations. Minimum 5 years experience in pipeline integrity and compliance issues or equivalent.	Bob Pyle, Manager, Pipeline and Marine Logistics	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation.	Robert Chambers, Brein Vierra, Pipeline Engineering Consultants. Shane Manning Pac Energy Facility Engineer	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation. Science and Engineering degree.
Delivery Line #2	Andy Bradfield, Compliance Services Inc	>5 years oil field experience and science degree. Minimum 2 years experience in pipeline integrity issues or equivalent.	Rick Armstrong DOT Specialist	>5 years of experience in Oil Field and DOT Pipeline operations. Minimum 5 years experience in pipeline integrity and compliance issues or equivalent.	Bob Pyle, Manager, Pipeline and Marine Logistics	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation	Robert Chambers, Brein Vierra, Pipeline Engineering Consultants. Shane Manning Pac Energy Facility Engineer	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation. Science and Engineering degree.
Delivery Line #3	Andy Bradfield, Compliance Services Inc	>5 years oil field experience and science degree. Minimum 2 years experience in pipeline integrity issues or equivalent.	Rick Armstrong DOT Specialist	>5 years of experience in Oil Field and DOT Pipeline operations. Minimum 5 years experience in pipeline integrity and compliance issues or equivalent.	Bob Pyle, Manager, Pipeline and Marine Logistics	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation.	Robert Chambers, Brein Vierra, Pipeline Engineering Consultants. Shane Manning Pac Energy Facility Engineer	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation. Science and Engineering degree.
	Andy Bradfield, Compliance Services Inc	>5 years oil field experience and science degree. Minimum 2 years experience in pipeline integrity issues or equivalent.	Rick Armstrong DOT Specialist	>5 years of experience in Oil Field and DOT Pipeline operations. Minimum 5 years experience in pipeline integrity and compliance issues or equivalent.	Bob Pyle, Manager, Pipeline and Marine Logistics	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation.	Robert Chambers, Brein Vierra, Pipeline Engineering Consultants. Shane Manning Pac Energy Facility Engineer	>5 years of oil field and petroleum pipeline experience in construction and integrity remediation. Science and Engineering degree.

Integrity Management Plan
Hazardous Liquid Pipelines
Element #3: Review of Assessment Results

Ref: 49 CFR 195.452(g)	Updated: Oct 2008

In This Element:

3.1 Summary of Assessment Result Requirements [195.452(g)]

The Integrity Management Program will include an analysis that integrates available information about the integrity of its pipelines and the consequences of failure. The information to be reviewed includes:

- Information critical to determining the potential for, and preventing, damage due to excavation, including current and planned damage prevention activities, and development or planned development along the pipeline segment;
- Data gathered through the integrity assessment as required by 195.452 and this Company Integrity Management Program;
- Data gathered in conjunction with other inspections and tests, including surveillance, patrols, corrosion control monitoring, and cathodic protection surveys required by the *pipeline regulations*; and
- Information about how a failure would affect the high consequence area, such as location of the water intake.

3.2 Review of Assessment Results and Information

In conducting a periodic evaluation of the integrity of its pipelines affecting HCAs, the Company will gather, integrate, and evaluate information in the following areas which they believe has a direct and important influence on the integrity of a pipeline:

- Development, excavation, and damage prevention activities along pipeline ROWs
- Data gathered from integrity assessments
- Data from CP surveys
- ROW surveillance
- Internal corrosion reports and pipe exposure reports
- Information about how a failure would affect a HCA

3.2.1 Damage Prevention and Public Awareness Program

The Company will emphasize monitoring of all excavation, development and construction activities along the pipeline ROW in accordance with API #1162 (Public Awareness Program for Pipeline Operators).

3.2.2 Data from Assessment Inspections

The data gathered from instrumented internal inspection tool surveys will be carefully analyzed and anomalies will be prioritized by severity to ensure that the most critical anomalies are repaired first. Information on the most severe anomalies will be obtained immediately from the vendor Tool Company, after the assessment is completed and prior to the "calibration" of the results and receipt of the final report in order to give immediate attention to anomalies that present a potential threat to the integrity of the pipeline.

When a previously inspected pipeline is inspected, the inspection results will be compared to the previous inspection results to determine corrosion growth at previously detected corrosion anomalies and to determine if new corrosion is occurring. After a full analysis of the assessment information gathered from an inspection is complete, a repair and corrosion mitigation plan will be developed to make required repairs and to implement corrective action as necessary for corrosion prevention.

3.2.3 Data from Required Surveys/Inspections

Data gathered from aerial ROW surveys, annual CP surveys, internal corrosion monitoring reports, pipe exposure reports, and other inspection information related to monitoring pipeline integrity will be reviewed by qualified personnel to determine any impact on integrity. The Corrosion Engineer or appropriate person reviews CP reports and corrosion and pipe exposure inspection reports as a method to determine the effectiveness of the corrosion prevention program. Operations Supervisors review ROW surveillance reports and other inspection records and take appropriate action when necessary to protect the integrity of the pipelines.

3.2.4 Information on Affect of Failure on HCA

New information that potentially increases the sensitivity of a HCA to the impact of a failure will be analyzed by the engineering and regulatory compliance staff. An analysis will be performed to determine how a failure might affect a HCA and what measures, if any, should be considered to mitigate the affects of any failure. Information related to pipeline integrity and potential impacts to HCAs in the event of a failure will be provided to the engineering staff.

3.3 Qualification of Employees

The Company will ensure all employees who review and evaluate integrity assessment results are qualified to perform the assigned work. The Company will develop a personal profile for each person involved in assessment reviews. The personal profile will include the following minimum information and be approved by the Operations Manager. The IMP records binder/files contains a list of the Company personal profiles for IMP.

- Name and job title
- Description of personal skills, education, training, and experience that demonstrates the individual's qualification and proficiency
- Identification of additional qualification needs if needed for the assigned IMP assessment role
- Plan for additional training or skills needed to achieve and/or maintain qualification

The company will develop a plan and schedule to provide additional training or skills acquisition to achieve and maintain qualification requirements, as applicable.

3.4 Qualification of Contractors and Vendor Specifications

Vendor contracts and purchase orders dealing with inline inspection (ILI) tools shall be written to include requirements for IMP qualifications, guidelines for resolving problems dealing with IMP, specifications for inspection tools/services, immediate reporting to the Company of severe anomalies, and IMP 180 day reporting requirements.

The Company will ensure all contractors who review and evaluate integrity assessment results are qualified to perform the assigned work. The Company will review resumes and job history for each contract person involved in assessment reviews. The person's profile will include the following minimum information, meet the qualification requirements listed below in section 3.5, and be approved by the IMP Leader.

- Name and job title
- Description of personal skills, education, training, and experience that demonstrates the individual's qualification and proficiency

Contracts and purchase orders will also describe how the Company and vendor will handle any disputes regarding IMP. Vendor inline inspection reports shall not be withheld by the vendor company during dispute periods. Vendors will be required under contract to submit inline inspection reports within the 180 day period required by the regulations.

Also, the contract shall require the vendor company to immediately report any severe or significant anomalies. Immediate means as soon as practical for a period not to exceed 5 days upon discovery. Severe or significant anomalies are defined to mean "Immediate Repair Condition" as defined in the IMP regulation and this plan. The company will also specify which anomaly "interaction rule" will be applied. The inline inspection tools shall also be described in detail on each contract and purchase order.

3.5 Qualification of Personnel Reviewing Integrity Data

Purpose and Background

The purpose of this procedure is to establish the process for ensuring that data gathered through periodic evaluation of pipelines in accordance with the Integrity Management Program is analyzed by personnel qualified to determine the integrity of the pipe from the data.

Inspections conducted under the company's Integrity Management Plan will result in data that must be analyzed by personnel qualified to do so. In-line inspection data requires highly-specialized expertise and the benefit of experience to interpret the often cryptic analog indications provided by the tool. Hydrostatic pressure testing requires compliance with 49 CFR, Part 192, Subpart J, to be valid and requires expertise in compensating for varying factors such as temperature and elevation.

In-Line Inspection

Due to the extensive training and experience required to adequately interpret analog in-line inspection data, the company will rely on its ILI vendors to provide the expertise required for data analysis. The company will only contract with reputable in-line inspection vendors with at least three years of proven experience in inspecting and evaluating pipe using the tools for which they are being contracted. Specifically, the ILI vendor responsible for interpreting smart pig data will have the following qualifications:

- Three years of experience with tools used for the inspection
- The personnel operating the ILI systems and the personnel taking, reducing, analyzing and reporting the resultant data shall be qualified in accordance with API #1163 and ASNT ILI-PQ, level II.

The company may conduct its own review of the data and the interpretations provided by the vendor as a quality control check. The person conducting such QC reviews should have had at least one year of experience in reviewing ILI raw data, but in no case shall the reviewer over-ride the interpretations of the vendor unless it results in a more conservative response to the data. In all cases, questions regarding a vendor's interpretation shall be referred back to the vendor for review and clarification.

Hydrostatic Testing

Hydrostatic testing shall be performed in compliance with 49 CFR, Part 195, Subpart E. The hydrotest will be conducted under the direction of a company employee who has been qualified to the company's Operator Qualification Program. A company engineer, consulting engineer, or California State Fire Marshall (CSFM) certified testing company shall certify the hydrostatic test.

Direct Assessment

Direct Assessment methodologies that may be employed in the determination of the company pipeline integrity shall be conducted by reputable vendors with proven experience in applying the methodology. The company will only contract with reputable direct assessment vendors with at least three years of proven experience in inspecting and evaluating pipe using the methodologies from NACE RP 0502.

3.6 Validation of Assessment Results

After ILI tools are run, the company will perform excavations or use other techniques to verify the accuracy and reliability of the inspection tools in order to have confidence in the assessment results. Verification of tool tolerance shall be one piece of information that should be verified. Tool tolerance is specific to each tool type and manufacturer.

The primary method the company will use to validate and calibrate ILI tool data will be through excavations. The IMP Leader and/or IMP Team will make the determination on the appropriate number and location of validation digs. The company will use a minimum of two excavation digs unless the IMP Leader and IMP Engineer can justify a lesser number. If data comparison from the two excavations conflicts with the ILI tool anomaly data, a least one other excavation dig shall be performed. The company will select the two most severe locations for the two validation digs, unless the engineer can justify otherwise. The engineer shall document their excavation decision based on statistics or other sound engineering practices.

The actual anomaly characteristics (type and dimensions) will be compared to the anomaly characteristics inferred from the ILI tool data to calibrate the ILI tool data to match known examples of detected anomalies. The company will work with the ILI vendor to assure the assessment data is valid.

The engineer shall prescribe the required information to be gathered during an excavation to ensure proper validation of the inline inspection tools. These verifications will be selected to verify tool accuracy for various types of anomalies, including but not limited to, internal corrosion, external corrosion, dents, ovality, gouges, and other types of anomalies. In the case of metal loss anomalies, an onsite UT tool will be used to determine the actual remaining wall thickness in order to verify or eliminate the possibility of internal corrosion.

3.7 Integration of Other Data with Assessment Results

The Company will supplement inline inspection assessment with additional processes of assessment. These additional processes include data gathered in conjunction with other ILI inspections, O&M inspections and tests, including surveillance, patrols, corrosion control monitoring, and cathodic protection surveys required by the pipeline regulations.

3.8 Identifying and Categorizing Defects

Discovery of a condition occurs when the Company has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. Depending on circumstances, the Company may have adequate information when it receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, or when it receives the final internal inspection report. The Company is required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity assessment, unless the operator can demonstrate that the 180-day period is not feasible. The integrity assessment will be complete when the internal inspection tool is removed from the pig trap.

The engineering staff will analyze the integrity assessment final report and categorize reported anomaly conditions per the evaluation and repair schedule in this IMP program. See IMP records binder/files for repair schedule. If the Company will not be able to meet the schedule, a record will be placed in the Integrity Management Program file by the engineering staff explaining why the schedule cannot be met and stating that the changed schedule will not jeopardize public safety and/or environmental protection. The conclusion of the assessment review shall be documented by the engineer. The summary report shall include any conclusions, identification of any integrity issues, potential trends, and other appropriate integrity issues.

195.452 (h) (3) requires the Company to notify OPS if they are unable to meet the repair schedules and cannot provide safety through a temporary reduction in operating pressure. Such notifications should explain the reasons why the repairs cannot be made, describe actions being taken to resolve the issues precluding repair work, and indicate when these issues are likely to be resolved. The Company will attempt to submit notifications as early as possible, to allow time for OPS review.

The notification will be sent to the following address:

Information Resources Manager
Office of Pipeline Safety
Pipeline & Hazardous Materials Safety Administration
(PHMSA)
U.S. Dot, Room 7128
400 Seventh Street SW
Washington DC 20590, or
Fax Number (202) 366-7128

3.9 Documentation and Distribution of Assessment Results

All reviews of inline inspection reports shall include any conclusions, identification of any integrity issues and any potential trends. Assessment results conclusions will be retained for the life of the pipeline. Assessment results will only be distributed to the appropriate IMP Team members and management.

The engineer reviewing the inline inspection report shall request feedback from the vendor in regards to the tool performance and results. This report shall be maintained as part of the IMP records.

3.10 Hydrostatic Pressure Testing

When pressure testing is the selected method of assessment, it will be performed in accordance with 49 CFR 195 subpart E and the Company O&M procedures. Pressure testing will be used as the primary assessment method when internal inspections are not practical. The IMP Leader shall review all pressure test results and determine the cause of failures, analysis of pressure reversals, and validate test acceptance and validity.

3.11 Other Assessment Technologies

If the Company decides to perform assessments using other technology, the Company will develop IMP procedures for selection of technology, review of industry standards, validation of other technology results, and procedures that address reporting and analysis of anomalies and defects.

3.12 Implementation of Element #3

The Company will use the attached agenda, "LIQ IMP element #3 & #8, Review of Assessment Results and Data Gathering agenda and action items", for implementation of this element. This review will be conducted once per calendar year not to exceed 18 months.

3.13 Records

1. Document using one or more of the following:
   - Baseline Assessment Results (ILI reports, pressure test reports, other technology reports)
   - Decision processes, rational, and assumptions
   - O&M data and records
   - Employee qualification records
   - Vendor specifications
   - Dig validation reports

Ref: 49 CFR 195.452(g)	Updated: Oct 2008

3.14 Related References and Documents

1. 49 CFR 195.452, 195,450, 195.6

2. API #1160, Managing System Integrity for Hazardous Liquid Pipelines, Section 9, pages 21-29, 1st Edition, November 2001

3. OPS Frequently Asked Questions (FAQs):
   Section #6, Integrity Assessment Methods, Sept 17, 2007

4. OPS IMP Protocols
   Integrity Assessments Results Review, section #3, Oct 2006

5. Appendix C to Part 195, Guidance for Implementation of Integrity Management Program:
   Section #2 – Risk Factors for Establishing Frequency of Assessment, pages 3-4
   Section #4 – Types of Internal Inspection Tools to Use

CPF 5-2008-7002M
Line 2 and 3

In This Element:

2.1 Summary of Baseline Assessment Requirements [195.452(c), (d) & (e)]

The Operator must include methods to assess the integrity of the pipeline and a prioritized schedule for completing the integrity assessments of their pipe in the Baseline Assessment Plan. The highest risk pipeline segments will be assessed first, with 50 percent being completed by ***August 16, 2005***. The remaining lines that are determined to potentially affect HCAs will be assessed by ***February 17, 2009***.

The baseline assessment plan must contain the following minimum requirements:

- Identify all pipeline segments that could affect HCAs,
- Specify the integrity assessment method or methods for each segment that could affect an HCA (acceptable methods *include, internal inspection*, pressure testing, or other technology that the operator demonstrates can provide an equivalent understanding of pipe condition),
- Provide a schedule for assessment of each segment, and
- Explain the technical basis for integrity assessment method(s) selection and risk factors used in scheduling the assessments.

2.2 What is an Assessment?

An assessment constitutes all of the actions that must be performed to determine the condition of the pipe. This includes conducting internal inspections or hydrostatic tests or implementing other technology that provides an equivalent understanding of the condition of the line (with 90-day advance notification to OPS). Any anomalies identified by the assessment that meet criteria in 195.452(h) must be remediated in accordance with the Company schedule. But these remedial activities are not considered part of the assessment.

2.3 Baseline Assessment Methods [195.452(c)]

The Company will perform baseline assessments by using one or more of the following acceptable integrity assessment methods.

- Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;
- Pressure test conducted in accordance with 195.452(e);
- External corrosion direct assessment [rule revision, October 25, 2005, (70 FR 61571)]
- Other technology that the Company demonstrates can provide an equivalent understanding of the condition of the line pipe. When the Company chooses this option, the Office of Pipeline Safety (OPS) will be notified 90 days before conducting the assessment, by sending this information to one of the following:

Facsimile: (202) 366-7128

Written Notice:

Information Resources Manager
Office of Pipeline Safety
Pipeline & Hazardous Materials Safety Administration (PHMSA)
U.S. Department of Transportation,
400 Seventh Street SW., Room 7128
Washington, DC 20590

The company will apply the most appropriate integrity assessment method or methods to address the specific integrity threats identified for the segment through the updated risk analysis, periodic evaluations, previous assessments, and industry experience.

2.3.1 Internal Inspections

The primary baseline assessment method will be internal "smart pig" inspections. This method is widely regarded as the most thorough for evaluating the condition of pipelines.

If ILI tools are used, they must be capable of detecting corrosion and deformation anomalies including dents, gouges and grooves. The Company will consider different types of internal inspection tools for the integrity assessment from the following list. Normally, a magnetic flux leakage (MFL) metal loss tool will be run first. If dents, gouges, or grooves are detected, then a geometry/deformation tool or physical inspection will be employed to inspect for all dents, gouges, and grooves. MFL tools can detect the presence of dents, but not reliably size them. Thus, PHMSA Pipeline Safety considers that any indication of a dent found using an MFL tool is potentially a defect meeting the repair criteria in the rule, until the contrary is demonstrated. PHMSA Pipeline Safety will accept an assessment conducted using an MFL tool without a concurrent deformation tool run if the company specifically directs its ILI vendor to identify all potential dents. All such potential dents must then be excavated and examined, and those meeting rule repair criteria must be remediated. If all potential dents are not excavated, then a subsequent assessment using a deformation tool or hydrostatic test must be conducted on an expedited basis.

The assessment methods selected for all low-frequency ERW pipe or lap-welded pipe susceptible to longitudinal seam failure are capable of assessing seam integrity and of detecting corrosion and deformation anomalies.

Inline inspection tools are only available in certain sizes and some line segments cannot accommodate them. In those cases, alternate inspection techniques will be implemented. The type of tool or tools the Company selects will depend on the results from previous internal inspection runs, information analysis and risk factors specific to the pipeline segment:

- Geometry Internal Inspection Tools for detecting changes to ovality, e.g., bends, dents, buckles or wrinkles, due to construction flaws or soil movement, or other outside force damage;
- Metal Loss Tools (Ultrasonic and Magnetic Flux Leakage) for determining pipe wall anomalies, e.g., wall loss due to corrosion. Note, the anomalies interaction rule will be discussed and agreed upon with ILI vendor and documented in the company smart pig report.
- Crack Detection Tools for detecting cracks and crack-like features, e.g., stress corrosion cracking (SCC), fatigue cracks, narrow axial corrosion, toe cracks, hook cracks, etc.

API Standard #1160, Managing System Integrity for Hazardous Liquid Pipeline, will be used to assist in the determination of the proper inspection tool. See API #1160 guidance, see Table 9-1, Anomaly Types and Tools to Detect Them. Periodically, the Company will perform excavations to verify the accuracy and reliability of the inspection tools. Accuracy and reliability is specific to each tool type and manufacturer.

2.3.1-A Acceptable Integrity Assessment methods for ERW Pipe or Lap Welded Pipe Susceptible to Seam Failure

For ERW pipe or lap welded pipe susceptible to seam failures, the company will:

- Run an in-line inspection device(s) capable of detecting seam flaws, metal loss *corrosion, and deformation anomalies*, OR
- Perform a Subpart E hydrostatic test.

The Company will also supplement these methods with additional processes of assessment. These additional processes include liquid sampling for corrosion, internal corrosion monitoring, pipeline inspections, cathodic protection (CP), electrical isolation, pressure testing, and surveillance. All methods are discussed in more detail below.

2.3.2 Pressure Testing

Except as otherwise provided in 49 CFR 195 subpart E (195.300-310), no new segment of pipeline or a segment of pipeline that has been relocated or replaced can be operated until it has been pressure tested without leakage. If a leak or pressure discontinuity is found, it must be investigated to determine its cause. All testing is in accordance with the 49 CFR subpart E and the Company O&M Manual, procedure #15.01.

Pressure testing can be used as the primary assessment method in place of internal inspections. Hydrostatic testing is a valuable tool to destructively remove critical defects. Not all anomalies will be removed during a test; only those defects that reach a critical size will be removed during a test. Testing a pipeline segment above the operating pressure will demonstrate the absence of defects that could result in failure up to the test pressure.

Hydrostatic testing is not as valuable when used to identify corrosion, particularly localized corrosion. Therefore, when the Company selects pressure testing as the assessment method, the following additional data gathered in conjunction with other inspections and tests will be reviewed in addition to the pressure testing:

- Surveillance and patrols
- Corrosion control monitoring and cathodic protection surveys

2.3.2-A Internal Corrosion Monitoring

If corrosion is anticipated, the pipeline will utilize corrosion coupons to measure corrosion rates. Installation of coupons shall include schematic diagrams and a monitoring schedule, in accordance with the pipeline Operation and Maintenance (O&M) Manual and 49 CFR 195.418.

2.3.2-B Cathodic Protection

The pipeline CP system is tested annually for "pipe-to-soil" tests. Testing records are maintained and corrective action levels are established in accordance with the pipeline Operation and Maintenance (O&M) Manual and 49 CFR 195.414. Drawings, plot sheets, maps, or other records for the pipeline system and facilities showing the location of cathodically protected piping, tanks, CP facilities, and neighboring structures bonded to the system are also maintained.

2.3.2-C Internal & External Pipeline Inspections

Whenever any pipeline is exposed for any reason, appropriate inspections are conducted and are recorded in accordance with the pipeline Operation and Maintenance (O&M) Manual and 49 CFR 195.416(e) and 195.418(d). These include visual inspections of coating materials and internal or external evidence of corrosion. Pipeline inspections also include assessments of the offshore portion of the pipeline, including side-scan sonar or ROV survey assessments of unsupported pipeline spans.

2.3.2-D Surveillance and Leak History

The pipeline is visually inspection 26 times per year in accordance with the pipeline Operation and Maintenance (O&M) Manual and 49 CFR 195.412. The pipeline system is patrolled to observe surface conditions on and adjacent to the pipeline right-of-way (ROW) for indications of leaks, construction activity, exposed pipe, erosion, and other factors that may affect the safety and operation of the pipelines.

Also, the Company will inspect crossings under a navigable waterway, except offshore pipelines, at intervals not exceeding five years in accordance with the pipeline Operation and Maintenance (O&M) Manual and 49 CFR 195.412(b).

2.3.3 Internal Corrosion Monitoring

If external corrosion direct assessment (ECDA) is the selected method, the company will have a complete ECDA Plan that addresses the requirements of NACE RP0502-2002. [Note that review of specific ECDA plan details are covered under Protocols 7.05-7.08.] In addition, the company is expected to address:

a. A formal, documented process to ensure that individuals who implement and evaluate ECDA assessments are qualified to perform that work. Characteristics of an effective process include:
   i. A means to identify qualification requirements for the various ECDA steps,
   ii. Documentation that demonstrates the individual's qualifications and proficiency, and
   iii. Plan and schedule to provide additional training or skills acquisition to achieve and maintain qualification requirements, as applicable.
b. Requirements established by the company for any vendors conducting ECDA assessment activities (e.g., indirect inspection) to assure that the vendors understand their responsibilities in performing integrity assessments that comply with this rule.

2.3.4 Other Technology

If technology other than pressure testing, external corrosion direct assessment, or in-line inspection is planned for use, the company will submit a notification to PHMSA at least 90 days before conducting the assessment.

2.4 Baseline Assessment Schedule [195.452(d)]

Assessments will be performed at intervals determined by the Company based on segment-specific risk factors and/or other regulatory requirements. Assessment intervals will not exceed 5 years not to exceed 68 months unless the Company has sound technical justification for a longer interval and notifies OPS of its intent to use the longer period.

When the Company desires to use an interval in excess of 5 years, then the Company must notify OPS (see notification requirements below). The rule provides for intervals in excess of 5 years under two circumstances:

	Reasons for Exceeding 5 Year Interval:	Notification Requirement:
1.	If a reliable engineering analysis in conjunction with other technologies provide confidence the pipe is in good condition, or	Minimum of 270 days before the end of the five year period. [195.452 (j) (4)].
2.	If an integrity assessment device is temporarily unavailable.	Minimum of 180 days before the end of the five year period. [195.452 (j) (4)(ii)].

In both instances the Company will notify OPS stating their intention to extend the assessment interval and provide a justification for this extension. Extensions based on engineering analyses are only for limited situations and "not to exceed an additional two years whenever possible" (see preamble to the final rule). Strong risk-based analysis will be used as the primary technical justification to use inspection intervals longer than 5 years.

The IMP records binder/files contains the baseline assessment schedule. This schedule identifies the pipeline segments affecting HCAs, assessment method, risk ranking, and scheduled assessment dates.

The date on which an assessment is considered complete will be the date on which final field activities related to that assessment are performed, not including repair activities. That will be when a hydrostatic test is completed, when the last in-line inspection tool run of a scheduled series of tool runs is performed, or the date on which "other technology" for which an operator has provided timely notification is conducted. Evaluation of the assessment results, integration of other information, and repair of anomalies must still be performed in accordance with the requirements established for these activities in the rule. These activities are considered to occur after the completion of the "assessment".

2.5 Use of Prior Assessments [195.452(d)(2)]

As per 49 CFR 195.452, the Company may use assessments completed since February 15, 1999 (category 2 pipeline) to satisfy the baseline requirements. Most baseline assessments listed in the schedule have been completed since this date. However, when the Company uses these prior assessments as its baseline assessment, the Company will reassess the line pipe at an interval not to exceed five years or sooner if required by the Company assessment schedule (see 195.452(j)(3). Any additional assessments will be completed by August 16, 2005. Use of prior assessments must satisfy all the assessment method requirements listed under section 2.2.

2.6 Updates & Newly Identified HCAs [195.452(d)(3)]

When information is available from the information analysis review or other sources, the Company will incorporate the area into its baseline assessment plan as a HCA within one year from the date the area is identified. The Company will complete the baseline assessment of any segment that could affect the newly-identified HCA within five years from the date the area is identified. Potential sources of newly identified HCA are listed below:

- National Pipeline Mapping System (NPMS)
- US Census Bureau maps; updates that show population density around a pipeline segment has changed so as to fall within the definition of a HCA per 195.450.
- Updates to unusually sensitive area maps
- Company MOC
- Regulation changes or updates

Within one year of the identification of a new HCA, a risk analysis of the pipeline segment that could affect the newly identified HCA will be performed.

When information associated with the identification of a potential new HCA is received the information will be reviewed and a record of the date that a new HCA was identified will be included in the Integrity Management Program files. The identity of the person(s) making the identification shall also be included in the record. An operator must document, prior to implementing any changes to the plan, any modification to the plan, and reasons for the modification.

Insights learned from completed assessments and risk analysis shall implement in plan updates. All baseline assessment plans revisions will be documented, including the reason for the revision.

2.7 Risk Factors for Establishing Assessment Schedule [195.452(e)]

The Company has developed a prioritized ranking of pipeline segments for a Baseline Assessment Plan. The priority ranking is based on the proximity to an HCA as well as operating data, design data, and past integrity data. A full discussion of risk analysis is provided in element #5 of this IMP program.

The Company will use the following list of risk factors for establishing frequency of assessment.

Minimum Risk Factors for Establishing Frequency of Assessment

The Company will use the following list of risk factors for establishing frequency of assessment.

1. Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.
2. Results from previous assessments, testing/inspection. [195.452(h)]
3. Leak history.
4. Known corrosion or condition of pipeline. [195.452(g)]
5. Cathodic protection history.
6. Type and quality of pipe coating (disbonded coating results in corrosion).
7. Age of pipe (older pipe shows more corrosion–may be uncoated or have an ineffective coating) and type of pipe seam.
8. Product transported (highly volatile, highly flammable and toxic liquids present a greater threat for both people and the environment).
9. Pipe wall thickness (thicker walls give a better safety margin)
10. Size of pipe (higher volume release if the pipe ruptures).
11. Local environmental factors that could affect the pipeline
    - Geo-technical = seismic faults, landslides, subsidence, and soil condition
    - Climatic = permafrost, etc
    - Corrosivity of soil
12. Security of throughput (effects on customers if there is failure requiring shutdown).
13. Time since the last internal inspection/pressure testing.
14. Previously discovered defects/anomalies, including type, growth rate, and size.
15. Operating stress levels in the pipeline.
16. Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly impede access for spill response or any other purpose).
17. Physical support of the segment such as by a cable suspension bridge.
18. Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).
19. Other regulatory interval requirements
20. Construction activity in the area.
21. General health and safety factors (employees and public)
22. Environmental impacts
23. Property damage
24. Local economic impact
25. Other segment specific factors as determined by the Company

Other factors considered in the analysis will include information analysis, decisions about remediation, and preventive and mitigative actions.

Risk is an inherent part of life and is associated with pipeline activities. While the overall risk of an operating pipeline can be managed, changed, or possibly reduced, it cannot be reduced to zero. Understanding risk factors is an important part of an IMP, because it is used to identify mitigation strategies. The total risk for a particular pipeline segment is the summation of the risks from the various threats to that segment.

2.8 Implementation of Element #2

The Company will use the attached agenda, "LIQ IMP element #2, Baseline Assessment Plan (BAP) and Continual Assessment agenda and action items", for implementation of this element. Review of the BAP and continual assessment will be conducted once per calendar year not to exceed 18 months.

2.9 Records

1. Document BAPs using one or more of the following:
   - Baseline Assessment Plan (BAP) and Schedule
   - Decision processes, rational, and assumptions
   - Form PHMSA F 7000-1.1 (Mileage of Baseline Assessments)

2.10 Related References and Documents

1. 49 CFR 195.452, 195,450, 195.6

2. API #1160, Managing System Integrity for Hazardous Liquid Pipelines, Section 9, pages 21-29, 1st Edition, November 2001

3. OPS Frequently Asked Questions (FAQs):
   Section #4, Baseline Assessment Plans, Sept 17, 2007
   Section #5, Integrity Assessment Intervals, Sept 17, 2007

4. OPS IMP Protocols:
   Protocol Section #2, Baseline Assessment Plan, Oct 2006
   Protocol Section #7, Continual Process of Evaluation and Assessment, Oct 2006

5. Appendix C to Part 195, Guidance for Implementation of Integrity Management Program:
   Section #2 – Risk Factors for Establishing Frequency of Assessment, pages 3-4
   Section #4 – Types of Internal Inspection Tools to Use

Integrity Management Plan
Hazardous Liquid Pipelines
Element #4: Remediation and Repair Criteria

Ref: 49 CFR 195.452(h)	Updated: Sept 2008

In This Element:

4.1 Summary of Remediation Requirements [195.452(h)

Section 195.452(h) requires an operator to evaluate and remediate all pipeline integrity issues raised by the integrity assessment or information analysis. An operator must develop a schedule that prioritizes conditions discovered on the pipeline for evaluation *and remediation. The operator must notify the OPS if the operator can not meet the* schedule and can not provide safety through a temporary reduction in operating pressure. The following are some examples of conditions that an operator should schedule for evaluation and remediation.

4.2 Evaluation of Integrity Assessment Data & Remediation Process

Due to the complexity or raw in-line inspection data, the tool vendor will evaluate the information and provide a report to the Company. The Company then reviews and evaluates the in-line inspection report and develops a repair and mitigation strategy.

<u>Discovery of a condition</u> occurs when the Company has adequate information about the condition to determine that it presents a potential threat to the integrity of the pipeline. Depending on circumstances, the Company may have adequate information when it receives the preliminary internal inspection report, gathers and integrates information from other inspections or the periodic evaluation, or when it receives the final internal inspection report. The Company is required to obtain sufficient information about a condition to make this determination no later than 180 days after an integrity

assessment, unless the Company can demonstrate that the 180-day period is impracticable. The integrity assessment will be complete when the internal inspection tool is removed from the pig trap and data reviewed.

The engineering staff will analyze the integrity assessment final report and categorize reported anomaly conditions per the evaluation and repair schedule in this IMP program. If the Company will not be able to meet the schedule for any condition category, a record will be placed in the Integrity Management Program file by the engineering staff explaining why the schedule cannot be met and stating that the changed schedule will not jeopardize public safety and/or environmental protection.

195.452 (h) (1) requires the company to take prompt action to address all anomalous conditions that the company discovers through integrity assessment or information analysis ... evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity ... demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. A reduction in operating pressure cannot exceed 365 days *without the company taking* further remedial action to ensure the safety of the pipeline. The company will comply with § 195.422 when making a repair.

Temporary pressure reduction

The company must notify PHMSA, in accordance with 195.452(m), if the company cannot meet the schedule for evaluation and remediation required under 195.452 (h) (3) described below and cannot provide safety through a temporary reduction in operating pressure.

Long-term pressure reduction

When a pressure reduction exceeds 365 days, the company must notify PHMSA in accordance with paragraph (m) of this section and explain the reasons for the delay. The company must also take further remedial action to ensure the safety of the pipeline.

195.452 (h) (3) requires the Company to notify OPS if they are unable to meet the repair schedules and cannot provide safety through a temporary reduction in operating pressure. Such notifications should explain the reasons why the repairs cannot be made, describe actions being taken to resolve the issues precluding repair work, and indicate when these issues are likely to be resolved. The Company will attempt to submit notifications as early as possible, to allow time for OPS review.
The notification will be sent to the following address:

Information Resources Manager
Office of Pipeline Safety
Pipeline & Hazardous Materials Safety Administration
(PHMSA)
U.S. Dot, Room 7128
400 Seventh Street SW
Washington DC 20590, or
Fax Number (202) 366-7128

4.3 Schedules for Evaluation and Remediation

Data from integrity assessments will be evaluated and a schedule of field evaluation and remediation that is prioritized according to the severity of the reported anomalies described in the assessment final report will be developed. Also, see the discussion on risk analysis in element #5. The IMP records binder/files contain the remediation and repair schedule, if any. Anomaly conditions for evaluation and remediation will be prioritized as follows:

1. Immediate Repair Conditions
2. 60-day Conditions
3. 180-day Conditions
4. *Other Conditions*

Immediate Repair Conditions

Conditions which must be treated as immediate repair conditions are given in § 195.452 (h)(4)(i-iv) and listed below.

metal loss greater than 80 percent of nominal wall thickness

calculated burst pressure less than maximum operating pressure (MOP) at an anomaly

top dent with any *indication of metal loss, cracking, or stress riser*

top dent (above the 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter

Any anomaly judged to require immediate attention

To maintain safety, the operating pressure will be temporarily reduced or the pipeline will be shut down until the repair of these conditions is completed. The temporary reduction in operating pressure shall be calculated using the formula in Section 451.7 of ASME/ANSI B31.4. Where pressure reduction can not be calculated using Section 451.7, the Company engineering will document the basis for determining a safe operating pressure.

Ref: 49 CFR 195.452(h)	Updated: Sept 2008

The method described in section 451.7 of ASME/ANSI B31.4 is required by the rule and must be used for all circumstances for which it is appropriate (e.g., corrosion). When the method is applied based on in-service inspection log results, the tolerance of the inspection tool must be taken into consideration. That is, if the tool has a tolerance of plus or minus 10 percent, a best- estimate indication of 40 percent wall loss must be increased to 50 percent for use in the formula of section 451.7.

There are anomalies defined by the rule as immediate repair conditions for which the method of section 451.7 is not applicable (e.g., dents). The calculation in Section 451.7 of ASME/ANSI B31.4 is applicable to determining the remaining strength of pipe with corrosion defects or grind repairs (i.e., loss of wall thickness).

Pressure must be reduced for other types of immediate repair conditions, but the Company must develop appropriate engineering justification for the amount of pressure reduction. A reduction in operating pressure is intended to provide an additional safety margin until the defect can be remediated. To assure that additional margin is provided, the pressure reduction must be based upon pressures that the pipe has actually experienced, with the defect present (i.e., pressures for which safety has been demonstrated). These may be well below the "maximum operating pressure" for the pipe. For example, a reduction of 20 percent below the highest operating pressure actually experienced at the location of the defect within the two months preceding the inspection may provide the necessary additional safety margin.

Paragraph 195.452(h)(1) limits any reduction in operating pressure to <u>no more than 365 days before</u> an operator must take further remedial action to ensure the safety of the pipeline.

60 day condition: A defect or anomaly in the condition of the pipe that must be evaluated and repaired or remediate within 60 days of discovery. The rule identifies the following as 60-day conditions.

- A dent located on top of the pipeline (above 4 and 8 o'clock positions) with a depth greater than 3 percent of the pipeline diameter (greater than 0.25 inches for a pipeline diameter less than NPS 12)
- A dent located on the bottom of the pipeline that has any indication of metal loss, cracking or stress riser (NOTE: Top-of-the-pipe dents with metal loss, cracking or stress riser are an immediate repair condition)

180 day condition: A defect of anomaly in the condition of the pipe that must be evaluated and repaired or remediate within 180 days of discovery. The rule identifies the following as 180 conditions.

- A dent with depth greater than 2% of the pipeline's diameter (0.25 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld
- A dent located on the top of the pipeline (between the 4 and 8 o'clock position) with a depth greater than 2% of the pipeline's diameter (0.25inches in depth for a pipeline diameter less than NPS 12)

- A dent located on the bottom of the pipeline with a depth greater than 6 % of the pipeline's diameter
- A calculation of the remaining strength of the pipe shows an operating pressure that is less than the current established maximum operating pressure at the location of the anomaly (using suitable calculatingly methods)
- An area of general corrosion with a predicted metal loss greater than 50% of nominal wall
- Predicted metal loss greater than 50% of nominal wall that is located at a crossing of another pipeline, or is in an area with widespread circumferential corrosion, or is in an area that could affect a girth weld
- A potential crack indication that when excavated is determined to be a crack
- Corrosion of or along a longitudinal seam weld
- A gouge or groove greater than 12.5% of nominal wall

Other Conditions

The following is a list of some conditions not included in the categories listed above that will be considered for evaluation and remediation:

Significant changes since the previous assessment

Mechanical damage located on top of the pipe

An anomaly with abrupt features that could act as a stress concentrator

An anomaly longitudinal in nature

An anomaly over a large area

An anomaly located in or near a casing, foreign pipeline crossing, or area subject to CP interference

4.4 Repair and Remediation Methods

All repairs will be made in accordance with 195.422 and the Company O&M Manual. API #1160, Managing System Integrity for Hazardous Liquid Pipelines will be used as a guide to assist in determination of the type of repair/remediation that will be employed. See table 9-2, Summary of Commonly Used Permanent Pipeline Repairs.

When the repair is a result of the integrity management regulations and this IM program, the data will be used as input on PHMSA Form F 7000-1.1.

4.5 Safety Related Conditions

Evaluation of integrity assessment data shall include a review of the requirements for safety related conditions. Details on safety related conditions can be found in the Company O&M manual and 49 CFR 191.23 and 191.25.

4.6 Implementation of Element #4

The Company will use the attached agenda, "LIQ IMP element #4, Remediation and Repair agenda and action items", for implementation of this element. This review will be conducted once per calendar year not to exceed 18 months.

4.7 Records

1. Document using one or more of the following:
   - Baseline Assessment Results (ILI reports, pressure test reports, other technology reports)
   - IM Program Remediation Schedule Worksheet
   - Decision processes, rational, and assumptions
   - O&M repair and pressure test records
   - Reports to PHMSA (when remediation schedule can not be met)
   - PHMSA Form 7000-1.1
   - Safety Related Condition Report, if applicable

4.8 Related References and Documents

1. 49 CFR 195.452(h)(1), (h)(3), & (h)(4)

2. API #1160, Managing System Integrity for Hazardous Liquid Pipelines, Section 9.6, 9.7, and table 9-2, pages 27-29, 1st Edition, November 2001

3. OPS Frequently Asked Questions (FAQs):
   Section #7, Anomaly Repair and Excavation, Sept 17, 2007

4. OPS IMP Protocols
   Remediation, section #4, Oct 2006

5. Appendix C to Part 195, Guidance for Implementation of Integrity Management Program:
   Section #7 – Conditions That May Impair a Pipeline's Integrity, page 10

CPF 5-2008-7002M
Line 4

SPBPL IMP DATA REVIEW SUMMARY

HCA Segment Description
Reference: 49 CFR 192.917(a), IMP Element #2.3
Updated: Feb 25, 2009

Data Category	Type of Data	Example Factors	Person(s) Conducting Revelw	Date of Review	Comments and Action Items
Data gathered from development, excavation, and damage prevention activities along pipeline ROW.	Development	Expansion in LB Port	Rick Armstrong, Andy Bradfield,	2/25/2009	Major work for 2009-20011
	Excavation	Ongoing excavations due to expansion pf Port.	Rick Armstrong, Andy Bradfield,	2/25/2009	More frequent ROW inspections
	Damage Prevention Activities Taken by the company.	One call seminars or other education of excavators, mailers, third party damage, etc.	Rick Armstrong, Andy Bradfield,	2/25/2009	Public Awareness mailer sent out annually
Data Category	**Type of Data**	**Example Factors**	**Person(s) Conducting Revelw**		**Comments and Action Items**
Data gathered from integrity assessment, ILI with Smart Pig	Immediater repair condition	None	Rick Armstrong, Andy Bradfield,	2/25/2009	NA
	60 day repair condition	None	Rick Armstrong, Andy Bradfield,	2/25/2009	NA
	180 day repair condition	One on Elly Riser	Rick Armstrong, Andy Bradfield,	2/25/2009	Was in .844 WT pipe but repaired
	Conditions to monitor	Laminations in 16" on next UT Smart Pig run	Rick Armstrong, Andy Bradfield,	2/25/2009	
Data Category	**Type of Data**	**Example Factors**	**Person(s) Conducting Revelw**		**Comments and Action Items**
Data gathered from CP surveys, CP specs, etc.	CP surveys	CP survey (pipe to soil), close interval survey, interference currents, bonds readings, rectifier readings, test station maintenance, etc.	Rick Armstrong, Andy Bradfield,	2/25/2009	Pipe to soil potentials adequate
	CP System Specs:	Sacrificial Anode	Rick Armstrong, Andy Bradfield,	2/25/2009	Good Cond.
	Coating type and condition, etc.	CP system type, coating type, type of soil, etc.	Rick Armstrong, Andy Bradfield,	2/25/2009	Coal Tar Enamel and Felt. Concrete coat added offshore
	Internal corrosion	Gas analysis, coupons, corrosion probes, etc.	Rick Armstrong, Andy Bradfield,	2/25/2009	Coupons satisfactory. Batching chemical program every 3 weeks. Internal corrosion stablized.
	External corrosion	Exposed pipe reports	Rick Armstrong, Andy Bradfield,	2/25/2009	When exposed a report is documented
	Atmospheric corrosion	Atmospheric inspection reports	Rick Armstrong, Andy Bradfield,	2/25/2009	None noted.

Data Category	Type of Data	Example Factors	Person(s) Conducting Revelw		Comments and Action Items
ROW Surveillance	Patrol type and frequency	Flying, driving, walking, boat. Inspected at minimum required frequency or at more frequency interval.	Rick Armstrong, Andy Bradfield,	2/25/2009	ROW Inspected minimum of once a week by Boat and Auto
	Condition of right-of-way	Width, depth of burial, activity level, encroachment, pipeline markers/signs, class location, highway and railroad crossings, waterway crossings, etc.	Rick Armstrong, Andy Bradfield,	2/25/2009	ROW Inspected minimum of once a week by Boat and Auto
Data Category	**Type of Data**	**Example Factors**	**Person(s) Conducting Revelw**		**Comments and Action Items**
Information about how a failure could affect a HCA	Environmental sensitivity	Environmentally sensitive area, or distance to environmentally sensitive area.	Rick Armstrong, Andy Bradfield,	2/25/2009	Pipeline in HCA
	Public and personnel safety	Class location, sites where the public would congregate (Beach's, parks, places of work etc.)	Rick Armstrong, Andy Bradfield,	2/25/2009	Pipeline is in a HCA
	Pipeline profile	What is the profile of the pipeline as it relates to location near populated areas/bldgs?	Rick Armstrong, Andy Bradfield,	2/25/2009	Spill offshore could affect waterfront property. Onshore would affect low population dencity area's
	Potential for ignition	What is the potential for ignition?	Rick Armstrong, Andy Bradfield,	2/25/2009	Low. Apx. 85.0 Deg.
	Location of nearest response personnel	What is the location of the nearest response personnel?	Rick Armstrong, Andy Bradfield,	2/25/2009	Local, with 5-10 Mins
Data Category	**Type of Data**	**Example Factors**	**Person(s) Conducting Revelw**		**Comments and Action Items**
Alternate Modes of Operation	Pipe spec's,	Pipe specs will include the SMYS rating	Rick Armstrong, Andy Bradfield,	2/25/2009	Current operations have a very low stress on the pipeline, 16% of SMYS
	Affects of anomalies on MOP	Corrosion cell that reduces WT	Rick Armstrong, Andy Bradfield,	2/25/2009	No anomalies in reducing WT by 20% or more
	MOP and NOP	Max MOP is 1152# while NOP is 260-400#	Rick Armstrong, Andy Bradfield,	2/25/2009	Current operations have a very low stress on the pipeline, 16% of SMYS
	Cycling times	How often does pipeline startup and shutdown in 24 hours	Rick Armstrong, Andy Bradfield,	2/25/2009	ROW Inspected minimum of once a week by Boat and Auto

SPBPL AUTOMATIC SHUTOFF VALVE (ESD) RISK ASSESSMENT

Updated: 2-25-2009
Segment: SPBPL 16" & Beta 10" lines

Factor #	Factor Description	ESD Risk Analysis Question	Mitigative Measures Currently In Place	S	L
1	Swiftness of leak detection and pipe shutdown capabilities	How quickly will the system detect a leak and shutdown the pipeline?	Atmos Pipe LDS on 16". Intellution on 10" which is monitored by Crimson PL	2	5
2	Type of product being transported	High H2S, Flash Point	Low H2S facility, Flash 85 Deg.	2	4
3	Operating pressure	What is the operating pressure? The higher the pressure the higher the risk.	*250-500* on 16" *200-400#* on 10"	2	4
4	Rate of potential release	What is the rate of potential release?	175 Bph on 16" 760 Bph on 10"	2	4
5	Pipeline profile	What is the profile of the pipeline as it relates to location near populated areas/bldgs?	Spill offshore could affect waterfront property. Onshore would affect low population dencity area's	2	4
6	Potential for ignition	What is the potential for ignition?	Low, Flash 85 Deg	2	4
7	Location of nearest response personnel	What is the location of the nearest response personnel?	5-10 Mins	2	4
			Total Risk Score =	14	29
			Average Risk Score (Total Risk Score Divided by Number of Risk Factors)	2	4

SPBPL Riser

SPBPL (CSFM # 0341)

Updated: Feb 18, 2009

(yellow)	= unknown data, or unsat data
(blue)	= no threat
(red)	= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
1	External corrosion	**Results from all previous testing/inspection integrity issues (smart pigs, pressure tests, ECDA, *other*). *[see 195.452(h)]***	Hydro test conducted in Sept 2000 with no leaks. Caliper Pig inspection 05, UT ILI in Sept 07, MFL ILI in Sept 07	ILI, pressure test, DA	
1	External corrosion	**Leak and repair history.**	No leaks. Repair to riser at splash zone (+13) due to Ext. Corr.	ILI, pressure test, DA	
1	External corrosion	**Cathodic protection history and known corrosion or condition of pipeline. [see 195.452(g)]**	CP survey history adequate, all readings above 850 mv criteria.	ILI, pressure test, DA	
1	External corrosion	**Type, quality, and condition of coating (disbonded coating increases likelihood of corrosion)**	Paint and coating on riser in good Cond. ROV survey in 07 showed no signs of disbondment	ILI, pressure test, DA	
1	External corrosion	**Age of pipe.** **Consider installing new** pipe to improve manufacturing process, seam *type, joint factor, and*	Installed in 1980	ILI, pressure test, DA	
1	External corrosion	**Pipe wall thickness (thicker walls give a better safety margin).**	0.844	ILI, pressure test, DA	
1	External corrosion	**Time since the last internal inspection/pressure testing.**	Sept 2007---- 1 year 5 months	ILI, pressure test, DA	
1	External corrosion	**Previously discovered defects/anomalies, including type, growth rate, and size.**	One corrosion pit at splash zone	ILI, pressure test, DA	
1	**External corrosion**	**Close interval survey**	**Yes 2-07**	**ILI, pressure test, DA**	
1	External corrosion	**Open hole inspections/exposed pipe reports.**	Yes, Pipe is exposed above the water line	ILI, pressure test, DA	
1	External corrosion	**Install more CP test stations**	NA ---	ILI, pressure test, DA	
1	External corrosion	**Local environmental factors that could affect the pipeline (corrosivity of soil, *MIC*, etc.)**	No soil testing on this segment.	ILI, pressure test, DA	
1	**External corrosion**	**Remote CP monitoring**	**Drop cell survey every year**	**ILI, pressure test, DA**	
1	**External corrosion**	**Guided wave technology**	**None**	**ILI, pressure test, DA**	
1	**External corrosion**	**Fill casing voids with inert materials**	**None**	**ILI, pressure test, DA**	
1	**External corrosion**	**DCVG survey (coating holidays)**	**None**	**ILI, pressure test, DA**	
1	External corrosion	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)	ILI, pressure test, DA	
1	External corrosion	Upgrade or change CP system design	Not required at this time.	ILI, pressure test, DA	

	SPBPL Riser				
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
1	External corrosion	Increase frequency of CP survey readings and/or revised O&M procedures.	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	*Increase frequency of integrity testing* (ILI, pressure test, DA, Other)	*Not required at this time.*	*ILI, pressure test, DA*	
1	**External corrosion summary**	**Threat Yes/No**	**Yes it is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.**		

	S. BPL Riser				
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	Internal corrosion	**Results from all previous testing/inspection integrity issues. [see 195.452(h)]**	None found	ILI, pressure test, DA	
2	Internal corrosion	**Leak and repair history.**	No repairs do to internal corrosion	ILI, pressure test, DA	
2	Internal corrosion	**Age of pipe.** Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Const. in 1980		
2	Internal corrosion	**Pipe wall thickness (thicker walls give a better safety margin).**	0.844	ILI, pressure test, DA	
2	Internal corrosion	**Time since the last internal inspection/pressure testing.**	1 year and five month's	ILI, pressure test, DA	
2	Internal corrosion	**Previously discovered defects/anomalies, including type, growth rate, and size.**	None discovered	ILI, pressure test, DA	
2	Internal corrosion	**Fluid analysis and characteristics of product transported (corrosive properties, etc.).**	Fluid analysis shows no corrosive properties.	ILI, pressure test, DA	
2	Internal corrosion	**Corrosion monitoring program**	Coupons show no corrosion. Corrosion inhibitor and biocide injected at recommended rates by Clariant	ILI, pressure test, DA	
2	Internal corrosion	**Elevation profile**	Plus 45' down to Minus 236'	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	**Increase wall thickness**	**Not needed.**	**ILI, pressure test, DA**	
2	Internal corrosion	Install corrosion detection devices (coupons, probes, etc.)	Coupons already in place	ILI, pressure test, DA	
2	Internal corrosion	Change operating parameters (particularly pressure and flow velocity and especially periods where there is no flow)	Not needed but system operates at steady state when shipping.	ILI, pressure test, DA	
2	Internal corrosion	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as coupon monitoring, chemical injection, etc.	**Only using DOT Qualified company personnel** for DOT task.	ILI, pressure test, DA	

	SPBPL Riser				
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	Internal corrosion	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of corrosion monitoring and/or revised O&M procedures.	Not needed	ILI, pressure test, DA	
2	Internal corrosion	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. *260-400 # (11% of SMYS)*	ILI, pressure test, DA	
2	Internal corrosion	Run cleaning pig and/or cleaning fluid through the line.	PER runs 2-3 pigs weekly	ILI, pressure test, DA	
2	Internal corrosion	Chemical injection for impurities	Yes	ILI, pressure test, DA	
2	Internal corrosion	Exposed pipe reports	Yes	ILI, pressure test, DA	
2	**Internal corrosion summary**	Threat YES/NO	**Yes is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.**		

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	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
3	Stress corrosion cracking	Age of pipe	29 Years	SCC specific DA	
3	Stress corrosion cracking	Operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)	SCC specific DA	
3	Stress corrosion cracking	Operating temperature	160 - 110 Degrees	SCC specific DA	
3	Stress corrosion cracking	Distance from compressor station	NA	SCC specific DA	
3	Stress corrosion cracking	Coating type	Paint and Coal Tar enamel with 15LBS felt	SCC specific DA	
3	Stress corrosion cracking	Past hydro static test information	NA	SCC specific DA	
3	**SCC Summary Comment:**	All of the following conditions must be present for SCC: (see ASME B31.8S, appendix section A3.3) 1) Operating stress greater than 60% SMYS 2) Operating temperature greater than 100 degrees F	**This segment does not meet the conditions of #1 and #3, therefore SCC is not a threat to this segment.**		
	Construction, Manufacturing,and Materials Threat Summary		**Yes this segment is considered a threat .**		

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	Updated: Feb 18, 2009		= no threat		
			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Pipe material	ASTM A-106 Grade B Seamless Steel Pipe	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Year of installtion	1980	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Manufacturing process	Normal. No cast iron pipe, no mechanically coupled pipe, no acetylene girth welds.	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Seam type	Seamless	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Joint factor	1.0 (195.106)	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Operating pressure history	System operates at steady state	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	MOP	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
4	Construction, Manufacturing, and Materials	% SMYS at MOP	31%		

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			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	**Results from previous testing/inspection. [see 195.452(h)]**	None found	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Leak and repair history.**	No leaks. Repair to riser at splash zone (+13) due to Ext, Corr.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Type, quality, and condition of pipe coating (disbonded coating results in corrosion).**	Paint above +13, Coal Tar Enamel with 15 LBS Felt below	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Age of pipe.** Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not needed, Installed 1980	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Characteristics of product transported (*highly volatile, highly* flammable and toxic liquids present a greater threat).**	Heavy Crude Oil	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Pipe wall thickness (thicker walls give a better safety margin).**	0.844	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Local environmental factors that could affect the pipeline (corrosivity of soil, subsidence, climatic)**	Wave action of ocean	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Time since the last internal inspection/pressure testing.**	1 year and 5 months	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

	SPBPL Riser				
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 16, 2009		= *no threat*		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	**Previously discovered *defects/anomalies*, including type, growth rate, and size.**	None to date	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Operating stress levels in the pipeline. Exposure of pipeline to exceed MOP**	PSH's set at 862#, PRV is set at 1100# *Below MOP of 1152#*	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Physical support** of the pipeline segment such as by a cable suspension bridge. Includes external loading and stress.	Support clamps on entire Ellys Platform	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	**Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).**	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	*Construction, Manufacturing, and* Materials	**Elevation profile**	Plus 45' down to Minus 250'	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	*Install new pipe to improve* manufacturing process, seam type, joint factor, and pipe type.	*Not Needed*	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Reduce operating stress level (% SMYS)	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Review and improve welding procedures	Approved welding procedures already in place.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

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	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be *Collected & Reviewed for* Each HCA Segment**	**Segment specific data and *summary comments:***	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Conduct NDT inspection on welds	Original welds x-rayed and inspected	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct exposed pipe inspections reports and bellholes.	Inspections performed twice annually.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	**Construction, Manufacturing,and Materials Threat Summary**		Yes considered a threat due to age of line.		

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	Updated: Feb 18, 2009		= no threat		
			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
5	Third Party Damage Threat	**Results from previous testing/inspection. [see 195.452(h)]**	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Leak and repair history.**	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Type, quality, and condition of pipe coating (disbonded coating results in corrosion).**	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Pipe wall thickness (thicker walls give a better safety margin).**	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).**	3111 Bbls worst case scenario from integreted contingency plan	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Time since the last internal inspection/pressure testing.**	1 Year and 5 Months	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Previously discovered defects/anomalies, including type, growth rate, and size.**	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.**	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Construction activity in the area.**	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [H.02.a]**	Only using DOT Qualified company personnel *for DOT task.*	ILI, pressure tests, *exposed pipe reports*	
5	Third Party Damage Threat	**Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]**	None	ILI, pressure tests, exposed pipe reports	

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	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
5	Third Party Damage Threat	**Participating in one-call systems and monitoring "One Call" activity more closely. [H.02.a]**	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If evidence of encroahment without monitoring, excavations or above gnd electrical survey per NACE RP-0502. [H.02.a]**	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Improve line marking**	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Install optical electronic detection and/or sound detection system.**	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Increase depth of cover**	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Line relocation	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Improve public education**	Meeting requirement See O&M procedure 3.03	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Improve Right-of-Way (ROW) *Maintenance***	Weekly boat patrols	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**More frequent ROW inspections**	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Mechanical pipe inspection**	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Additional pipe wall thickness**	none	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	**Pipeline marker tape over pipeline**	None	ILI, pressure tests, exposed pipe reports	
5	**Third Party Damage Threat Summary**		Yes this segment is considered a threat due to fact that third party damage is major cause of pipeline accidents nationwide.	ILI, pressure tests, exposed pipe reports	

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	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 16, 2009		= no threat		
			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
6	Incorrect Operations or Procedure Error Threat	Conduct self audits	Integrity program reviewed once per year. Audited by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Review and improve O&M procedures	Meets yearly requiremnts and been audited by agencies numerous times. Audited in by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Conduct training, or improve existing training	OQ trng in place.	Audits by agency, company or 3rd party	
6	**Incorrect Operations Threat Summary**		Yes this segment is considered a threat due to fact that incorrect operations is a cause of pipeline accidents nationwide.	Audits by agency, company or 3rd party	
7	Equipment Threat	**Leak and repair history.**	No leaks. Repair to riser at splash zone (+13) due to Ext. Corr.	Repair of replace equip	
7	Equipment Threat	**Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.**	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#	Repair of replace equip	
7	Equipment Threat	**Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).**	All standardized equipment used	Repair of replace equip	
7	Equipment Threat	Increase frequency of visual and *mechanical inspections*	*Inspected daily*	Repair of replace equip	
7	Equipment Threat	Improve or change design or materials	Always open to improvements, none needed a	Repair of replace equip	
7	Equipment Threat	Review and improve O&M procedures	None needed at this time		
7	**Equipment Threat Summary**		Yes this segment is considered a threat due to fact equipment failures can be a a cause of pipeline accidents.		

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			= *threat*		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Joint method (mechancial coupling, acetylene weld, arc weld)	All arc welded	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Topographical and soil conditions (unstable slope, water crossings, water proximity, soil liquefactions susceptibility)	Wave action can cause *damage*	*O&M inspections*	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Earthquake fault	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Profile of ground of ground acceleration near fault zones (>0.2 g acceleration)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Depth of frost line	NA	*O&M inspections*	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Year of installation	1980	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Pipe grade, diameter, wall thickness (internal stress calcs added to external loading, total stress not to excedd 100% SMYS)	ASTM A-106 Grade B Seamless Steel Pipe, .844 WT, 16 OD, 31% of SMYS	O&M inspections	

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	**Natural Forces Damage threat summary**		Yes this segment is considered a threat due to being in a fault zone.	O&M inspections	
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	**Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate**	Located in environmentally sensitive area.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	**Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).**	Heavy crude Oil		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	**Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).**	3111 as per ICP manual		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	**Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.**	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	**Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly**	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	High pressure shutdown set at 862# with ESD valves on both ends of the PL		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Relocate line	**None**		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install or improve computerized monitoring	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
9	**Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases Threat Summary**		**Yes this segment is considered a threat .**		
10	**Environmental Impact**	**Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate**	Line is within HCA		
10	*Environmental Impact*	***Characteristics of product* transported (highly volatile, highly flammable and toxic liquids present a greater threat).**	Heavy crude Oil		

SPBPL Riser

SPBPL (CSFM # 0341)

Updated: Feb 18, 2009

(yellow)	= unknown data, or unsat data
(blue)	= no threat
(red)	= threat

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Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
10	Environmental Impact	**Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).**	3111 Bbls worst case scenario from integrated contingency plan		
10	Environmental Impact	**Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.**	PSH's set at 862#, PRV is set at 1100#Below *MOP of 1152#*		
10	Environmental Impact	**Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly**	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
10	Environmental Impact	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is **Apx. 260-400 # (11% of SMYS)**		
10	Environmental Impact	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	High pressure shutdown set at 862# with ESD valves on both ends of the PL		
10	***Environmental Impact***	**Relocate line**	**None**		
10	Environmental Impact	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
10	Environmental Impact	Install or improve computerized monitoring	**ATMOS Pipe Leak detection. Installed in** 2001 and updated in 2008		
10	Environmental Impact	Review and improve O&M procedures	Meets yearly requiremnts and has been **audited by DOT & CSFM in 2008.**		
10	Environmental Impact	Conduct self audits	Integrity program (IMP), OQ and O&M **reviewed once per year.**		
10	Environmental Impact	Additional training on emergency procedures to reduce emergency response time with	*Annual training conducted*		
10	Environmental Impact	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
10	Environmental Impact	Reduce operating stress level (% SMYS)	MOP is 1152 but NOP is Ap. 260-400 # **Operating at 31% of SMYS**		
10	**Environmental Impact Threat Summary**		**Yes this segment is considered a threat .**		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
11	Property Damage	**Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.**	Line is within HCA		
11	Property Damage	**Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).**	Heavy crude Oil		
11	Property Damage	**Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).**	3111 Bbls worst case scenario from integrated contingency plan		
11	Property Damage	**Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.**	PSH's set at 862#, PRV is set at 1100#Below MOP of 1152#		
11	Property Damage	**Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that *make leak detection difficult without* specific sectional monitoring and/or significantly**	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
11	Property Damage	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
11	Property Damage	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	High pressure shutdown set at 862# with ESD valves on both ends of the PL		
11	*Property Damage*	*Relocate line*	None		
11	Property Damage	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
11	Property Damage	Install or improve computerized monitoring	**ATMOS Pipe Leak detection. Installed in** 2001 and updated in 2008		
11	Property Damage	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
11	Property Damage	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
11	Property Damage	Additional training on emergency procedures to reduce emergency response time with	*Annual training conducted*		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
11	Property Damage	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
11	Property Damage	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
11	**Property Damage Threat Summary**		Yes this segment is considered a threat .		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	**Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.**	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	**Conduct self audits**	Integrity program (IMP), OQ and O&M reviewed once per year.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct training, or improve existing training	OQ training in place		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
12	**Alternate Modes of Operation Threat Summay**		Yes this segment is considered a threat .		
13	**Interactive Threat**	Manufacturing defect activated by pressure cycling	Yes this segment is considered a threat .		Laminations identified in 9-07 ILI run. Classified as A-B-C. all listed as B's. (non-critical)
14	**Interactive Threat**	Corrosion accelerated by TPD	Yes this segment is considered a threat .		
15	**Interactive Threat**	Corrosion accelerated by outside force	Yes this segment is considered a threat .		
16	**Other segment specific threats summary**		**None**		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
1	External corrosion	Results from all previous testing/inspection integrity issues (smart pigs, pressure tests, ECDA, other). [see 195.452(h)]	Hydro test conducted in Sept 2000 with no leaks. Caliper Pig inspection 05, UT ILI in Sept 07, MFL ILI in Sept 07	ILI, pressure test, DA	
1	External corrosion	Leak and repair history.	No repairs do to external corrosion	**ILI, pressure test, DA**	
1	External corrosion	Cathodic protection history and known corrosion or condition of pipeline. [see 195.452(g)]	CP survey history adequate, all readings above 850 mv criteria.	ILI, pressure test, DA	
1	External corrosion	Type, quality, and condition of coating (disbonded coating increases likilihood of corrosion)	Coating in good Cond. ROV survey in 07 showed no signs of disbondment	ILI, pressure test, DA	
1	External corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and	Installed in 1980	ILI, pressure test, DA	
1	External corrosion	**Pipe wall thickness (thicker walls give** a better safety margin).	0.5	ILI, pressure test, DA	
1	External corrosion	Time since the last internal inspection/pressure testing.	Sept 2007---- 1 year 5 months	ILI, pressure test, DA	
1	External corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	Very minimal	ILI, pressure test, DA	**This is a baseline accessment, will reaccess on next UT ILI.**
1	**External corrosion**	**Close interval survey**	**Yes 2-07**	**ILI, pressure test, DA**	
1	*External corrosion*	Open hole inspections/exposed pipe reports.	NA	ILI, pressure test, DA	
1	External corrosion	Install more CP test stations	NA	ILI, pressure test, DA	
1	External corrosion	Local environmental factors that could affect the pipeline (corrosivity of soil, MIC, etc.)	No soil testing on this segment.	ILI, pressure test, DA	
1	**External corrosion**	**Remote CP monitoring**	**ROV survey bi-annually**	**ILI, pressure test, DA**	
1	**External corrosion**	**Guided wave technology**	**None**	**ILI, pressure test, DA**	
1	**External corrosion**	**Fill casing voids with inert materials**	**None**	**ILI, pressure test, DA**	
1	**External corrosion**	**DCVG survey (coating holidays)**	**None**	**ILI, pressure test, DA**	
1	External corrosion	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is **Apx. 260-400 # (11% of SMYS)**	ILI, pressure test, DA	
1	External corrosion	Upgrade or change CP system design	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of CP survey readings and/or revised O&M procedures.	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not required at this time.	ILI, pressure test, DA	

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
1	External corrosion summary	Threat Yes/No	Yes it is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.		

SPBPL Sub Sea

SPBPL (CSFM # 0341)

Updated: Feb 18, 2009

= unknown data, or unsat data

= no threat

= threat

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Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
2	Internal corrosion	Results from all previous testing/inspection integrity issues. [see 195.452(h)]	None found	ILI, pressure test, DA	
2	Internal corrosion	Leak and repair history.	No repairs do to internal corrosion	ILI, pressure test, DA	
2	Internal corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Const. In 1980		
2	Internal corrosion	Pipe wall thickness (thicker walls give a better safety margin).	0.5	ILI, pressure test, DA	
2	Internal corrosion	Time since the last internal inspection/pressure testing.	1 year and five month's	ILI, pressure test, DA	
2	Internal corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	None discovered	ILI, pressure test, DA	
2	Internal corrosion	Fluid analysis and characteristics of product transported (corrosive properties, etc.).	Fluid analysis shows no corrosive properties.	ILI, pressure test, DA	
2	Internal corrosion	Corrosion monitoring program	Coupons show no corrosion. Corrosion inhibitor and biocide injected at recommended rates by Clariant	ILI, pressure test, DA	
2	Internal corrosion	Elevation profile	Minus 236' at Elly up to 0' at Shoreline	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of integrity testing (*ILI, pressure test, DA, Other*)	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Increase wall thickness	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Install corrosion detection devices (coupons, probes, etc.)	Coupons already in place	ILI, pressure test, DA	
2	Internal corrosion	Change operating parameters (particularly pressure and flow velocity and especially periods where there is no flow)	Not needed but system operates at steady state when shipping.	ILI, pressure test, DA	
2	Internal corrosion	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as coupon monitoring, chemical injection, etc.	Only using DOT Qualified company personnel for DOT task.	ILI, pressure test, DA	
2	Internal corrosion	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of corrosion monitoring and/or revised O&M procedures	Not needed	ILI, pressure test, DA	

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	Internal corrosion	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)	ILI, pressure test, DA	
2	Internal corrosion	Run cleaning pig and/or cleaning fluid *through the line.*	PER runs 2-3 pigs weekly	ILI, pressure test, DA	
2	Internal corrosion	Chemical injection for impurities	Yes	ILI, pressure test, DA	
2	Internal corrosion	Exposed pipe reports	Yes	ILI, pressure test, DA	
2	**Internal corrosion summary**	**Threat YES/NO**	Yes is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.		

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3	Stress corrosion cracking	Age of pipe	29 Years	SCC specific DA	
3	Stress corrosion cracking	Operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)	SCC specific DA	
3	Stress corrosion cracking	Operating temperature	110 degrees to 60 degrees	SCC specific DA	
3	Stress corrosion cracking	Distance from compressor station	NA	SCC specific DA	
3	Stress corrosion cracking	Coating type	Coal Tar enamel with 15LBS felt, Concrete weight coat	SCC specific DA	
3	Stress corrosion cracking	Past hydro static test information	NA	SCC specific DA	
3	**SCC Summary Comment:**	All of the following conditions must be present for SCC: (see ASME B31.8S, appendix section A3.3) 1) Operating stress greater than 60% SMYS 2) Operating temperature greater than 100 degrees F	**This segment does not meet the conditions of #1 and #3, therefore SCC is not a threat to this segment.**		
	Construction, Manufacturing,and Materials Threat Summary		**Yes this segment is considered a threat .**		

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			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Pipe material	ASTM A-106 Grade B Seamless Steel Pipe	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Year of installtion	1980	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Manufacturing process	Normal. No cast iron pipe, no mechanically coupled pipe, no acetylene girth welds.	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Seam type	Seamless	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Joint factor	1.0 (195.106)	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Operating pressure history	System operates at steady state	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	MOP	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
4	Construction, Manufacturing, and Materials	% SMYS at MOP	31%		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Results from previous testing/inspection. [see 195.452(h)]	Lamenations discovered during 9/07 ILI.- all sub surface. Discovered 2 dents in pipeline during 2001 Geo tool run. They were caused during the const. of the line. Repaired with Struct. Clamps.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	**This is a baseline accessment, will reaccess on next UT ILI. Rated A,B or C A being best, no C's found**
4	Construction, Manufacturing, and Materials	Leak and repair history.	None due to subject	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Coal Tar Enamel with 15 LBS Felt, Concrete weight coat	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not needed, installed 1980	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy Crude Oil	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Pipe wall thickness (thicker walls give a better safety margin).	0.5	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Local environmental factors that could affect the pipeline (corrosivity of soil, subsidence, climatic)	Wave action of ocean	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Time since the last internal inspection/pressure testing.	1 year and 5 months	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Previously discovered defects/anomalies, including type, growth rate, and size.	None to date	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

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(blue)	= no threat
(red)	= threat

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Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
4	Construction, Manufacturing, and Materials	Operating stress levels in the pipeline. Exposure of pipeline to exceed MOP	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Physical support of the pipeline segment such as by a cable suspension bridge. Includes external loading and stress.	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Elevation profile	Minus 236' at Elly up to 0' at shoreline	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Install new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Reduce operating stress level (% SMYS)	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Review and improve welding procedures	Approved welding procedures already in place.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct NDT inspection on welds	Original welds x-rayed and inspected	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct exposed pipe inspections reports and bellholes.	Inspections performed twice annually.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	**Construction, Manufacturing,and Materials Threat Summary**		Yes considered a threat due to age of line.		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
5	Third Party Damage Threat	Results from previous testing/inspection. [see 195.452(h)]	Dent from anchor discovered in 1992 by Geo tool.	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Leak and repair history.	No leaks. Repaired dent in pipeline from anchor with structural clamp in 1992	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipe wall thickness (thicker walls give *a better safety margin*).	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	3111 Bbls worst case scenario from integreted contingency plan	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Time since the last internal inspection/pressure testing.	1 Year and 5 Months	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure *of pipeline to exceed MOP.*	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Construction activity in the area.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [H.02.a]	**Only using DOT Qualified company personnel** for DOT task.	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure tests, exposed pipe reports	
5	*Third Party Damage Threat*	*Participating in* one-call systems and monitoring "One Call" activity more closely. [H.02.a]	NA	ILI, pressure tests, exposed pipe reports	

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
5	Third Party Damage Threat	Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If evidence of encroahment without monitoring, excavations or above gnd electrical survey per NACE RP-0502. [H.02.a]	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve line marking	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Install optical electronic detection and/or sound detection system.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Increase depth of cover	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Line relocation	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve public education	Meeting requirement See O&M procedure 3.03	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve Right-of-Way (ROW) Maintenance	Weekly boat patrols.	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	More frequent ROW inspections	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Mechanical pipe inspection	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Additional pipe wall thickness	none	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline marker tape over pipeline	None	ILI, pressure tests, exposed pipe reports	
5	**Third Party Damage Threat Summary**		Yes this segment is considered a threat due to fact that third party damage is major cause of pipeline accidents nationwide	ILI, pressure tests, exposed pipe reports	

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
6	Incorrect Operations or Procedure Error Threat	Conduct self audits	Integrity program reviewed once per year. Audited by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Review and improve O&M procedures	**Meets yearly requiremnts and been audited by** agencies numerous times. Audited in by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Conduct training, or improve existing training	OQ trng in place.	Audits by agency, company or 3rd party	
6	**Incorrect Operations Threat Summary**		**Yes this segment is considered a threat due to fact that incorrect operations is a cause of pipeline accidents nationwide.**	Audits by agency, company or 3rd party	
7	**Equipment Threat**	**Leak and repair history.**	**NA - subsea pipeline**	**Repair of replace equip**	
7	Equipment Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure *of pipeline to exceed MOP.*	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#	Repair of replace equip	
7	Equipment Threat	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	NA	Repair of replace equip	
7	Equipment Threat	Increase frequency of visual and mechanical inspections	NA	Repair of replace equip	
7	Equipment Threat	Improve or change design or materials	**Always open to improvements, none needed a**	**Repair of replace equip**	
7	Equipment Threat	Review and improve O&M procedures	None needed at this time		
7	**Equipment Threat Summary**		**Yes this segment is considered a threat due to fact equipment failures can be a a cause of pipeline accidents.**		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Joint method (mechancial coupling, acetylene weld, arc weld)	All arc welded	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Topicgraphical and soil conditions (unstable slops, water crossings, water proximity, soil liquefactions susceptibility)	Wave action can cause damage	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Earthquake fault	Liquidification zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Profile of ground of ground acceleration near fault zones (>0.2 g acceleration)	Liquidification zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Depth of frost line	NA	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Year of installation	1980	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Pipe grade, diameter, wall thickness (internal stress calcs added to external loading, total stress not to excedd 100% SMYS)	API 5LX Grade X52, DSA, Cold Expanded, Steel Pipe 0.500 WT, 16 OD, 1152# MOP which is 31% of SMYS	O&M inspections	

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SPBPL (CSFM # 0341)

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Legend	
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Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
8	**Natural Forces Damage threat summary**		Yes this segment is considered a threat due to being in a fault zone.	O&M inspections	
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Located in environmentally sensitive area.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	3111 as per ICP manual		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	High pressure shutdown set at 862# with ESD valves on both ends of the PL		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Relocate line	None		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install H_2S sensors and/or fuel gas sensors	Not a high H_2S facility		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install or improve computerized monitoring	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
9	**Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases Threat Summary**		**Yes this segment is considered a threat .**		
10	**Environmental Impact**	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
10	Environmental Impact	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	*Heavy crude Oil*		
10	Environmental Impact	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	3111 Bbls worst case scenario from integreted contingency plan		
10	Environmental Impact	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100#Below MOP of 1152#		

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SPBPL (CSFM # 0341)

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Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
10	Environmental Impact	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
10	Environmental Impact	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is **Apx. 260-400 # (11% of SMYS)**		
10	Environmental Impact	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	High pressure shutdown set at 862# with ESD valves on both ends of the PL		
10	**Environmental Impact**	**Relocate line**	**None**		
10	Environmental Impact	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
10	Environmental Impact	Install or improve computerized monitoring	**ATMOS Pipe Leak detection. Installed in** 2001 and updated in 2008		
10	Environmental Impact	Review and improve O&M procedures	Meets yearly requiremnts and has been **audited by DOT & CSFM in 2008.**		
10	Environmental Impact	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
10	Environmental Impact	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
10	Environmental Impact	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
10	Environmental Impact	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is **Apx. 260-400 # (11% of SMYS)**		
10	**Environmental Impact Threat Summary**		**Yes this segment is considered a threat .**		
11	Property Damage	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
11	Property Damage	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
11	Property Damage	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	3111 Bbls worst case scenario from integreted contingency plan		
11	Property Damage	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100#Below MOP of 1152#		

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Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
11	Property Damage	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
11	Property Damage	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is **Apx. 260-400 # (11% of SMYS)**		
11	Property Damage	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	High pressure shutdown set at 862# with ESD valves on both ends of the PL		
11	**Property Damage**	**Relocate line**	**None**		
11	Property Damage	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
11	Property Damage	Install or Improve computerized monitoring	**ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008**		
11	Property Damage	Review and improve O&M procedures	Meets yearly requiremnts and has been **audited by DOT & CSFM in 2008.**		
11	Property Damage	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
11	Property Damage	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
11	Property Damage	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
11	Property Damage	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is ***Apx. 260-400 # (11% of SMYS)***		
11	**Property Damage Threat Summary**		**Yes this segment is considered a threat .**		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100#Below MOP of 1152#		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct training, or improve existing training	OQ training in place		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line,	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
12	Alternate Modes of Operation Threat Summay		Yes this segment is considered a threat .		
13	Interactive Threat	Manufacturing defect activated by pressure cycling	Yes this segment is considered a threat .		Laminations identified in 9-07 ILI run. Classified as A-B-C. all listed as B's. (non-critical)
14	Interactive Threat	Corrosion accelerated by TPD	Yes this segment is considered a threat .		
15	Interactive Threat	Corrosion accelerated by outside force	Yes this segment is considered a threat .		
16	Other segment specific threats summary		None		

SPBPL Onshore Segment #3: Shoreline to Beta Pump Station

SPBPL (CSFM # 0341)

Updated: Feb 18, 2009

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Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
1	External corrosion	Results from all previous testing/inspection integrity issues (smart pigs, pressure tests, ECDA, other). [see 195.452(h)]	Hydro test conducted in Sept 2000 with no leaks. Caliper Pig inspection 05, UT ILI in Sept 07, MFL ILI in Sept 07	ILI, pressure test, DA	
1	External corrosion	Leak and repair history.	None Due to external Corr.	ILI, pressure test, DA	
1	External corrosion	Cathodic protection history and known corrosion or condition of pipeline. [see 195.452(g)]	CP survey history adequate, all readings above 850 mv criteria.	ILI, pressure test, DA	
1	External corrosion	Type, quality, and condition of coating (disbonded coating increases likelihood of corrosion)	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	ILI, pressure test, DA	
1	External corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and	Installed in 1980	ILI, pressure test, DA	
1	External corrosion	Pipe wall thickness (thicker walls give a better safety margin).	0.500 and 0.375	ILI, pressure test, DA	
1	External corrosion	Time since the last internal inspection/pressure testing.	Sept 2007— 1 year 5 months	ILI, pressure test, DA	
1	External corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	Very minimal	ILI, pressure test, DA	***Baseline assessment on ILI run of 9/07. Will reassess next run***
1	External corrosion	Close interval survey	Yes 2-07	ILI, pressure test, DA	
1	External corrosion	Open hole inspections/exposed pipe reports.	Yes, always looked like new	ILI, pressure test, DA	
1	External corrosion	Install more CP test stations	None needed at this time	ILI, pressure test, DA	
1	External corrosion	Local environmental factors that could affect the pipeline (corrosivity of soil, MIC, etc.)	None needed at this time	ILI, pressure test, DA	
1	External corrosion	Remote CP monitoring	CP surveys performed annually	ILI, pressure test, DA	
1	External corrosion	Guided wave technology	None	ILI, pressure test, DA	
1	External corrosion	Fill casing voids with inert materials	None	ILI, pressure test, DA	
1	External corrosion	DCVG survey (coating holidays)	None	ILI, pressure test, DA	
1	External corrosion	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)	ILI, pressure test, DA	
1	External corrosion	Upgrade or change CP system design	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of CP survey readings and/or revised O&M procedures.	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not required at this time.	ILI, pressure test, DA	

	SPBPL Onshore		Segment #3: Shoreline to Beta Pump Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
1	External corrosion summary	Threat Yes/No	Yes it is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.		

	SPBPL Onshore		Segment #3: Shoreline to Beta Pump Station		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	Internal corrosion	Results from all previous testing/inspection integrity issues. [see 195.452(h)]	None found	ILI, pressure test, DA	
2	Internal corrosion	Leak and repair history.	No repairs do to internal corrosion	ILI, pressure test, DA	
2	Internal corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Const. in 1980		
2	Internal corrosion	Pipe wall thickness (thicker walls give a better safety margin).	0.500 to 0.375	ILI, pressure test, DA	
2	Internal corrosion	Time since the last internal inspection/pressure testing.	1 year and five month's	ILI, pressure test, DA	
2	Internal corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	None discovered	ILI, pressure test, DA	
2	Internal corrosion	Fluid analysis and characteristics of product transported (corrosive properties, etc.).	Fluid analysis shows no corrosive properties.	ILI, pressure test, DA	
2	Internal corrosion	Corrosion monitoring program	Coupons show no corrosion. Corrosion inhibitor and biocide injected at recommended rates by Clariant	ILI, pressure test, DA	
2	Internal corrosion	Elevation profile	0' at shoreline to Apx 15' at beta Station	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Increase wall thickness	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Install corrosion detection devices (coupons, probes, etc.)	Coupons already in place	ILI, pressure test, DA	
2	Internal corrosion	Change operating parameters (particularly pressure and flow velocity and especially periods where there is no flow)	Not needed but system operates at steady state when shipping.	ILI, pressure test, DA	
2	Internal corrosion	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as coupon monitoring, chemical injection, etc.	Only using DOT Qualified company personnel for DOT task.	ILI, pressure test, DA	
2	Internal corrosion	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of corrosion monitoring and/or revised O&M procedures.	Not needed	ILI, pressure test, DA	

	SPBPL Onshore	Segment #3: Shoreline to Beta Pump Station			
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	*Internal corrosion*	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)	ILI, pressure test, DA	
2	Internal corrosion	Run cleaning pig and/or cleaning fluid through the line.	PER runs 2-3 pigs weekly	ILI, pressure test, DA	
2	Internal corrosion	Chemical injection for impurities	Yes	ILI, pressure test, DA	
2	Internal corrosion	Exposed pipe reports	Yes	ILI, pressure test, DA	
2	**Internal corrosion summary**	**Threat YES/NO**	**Yes is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.**		

	SPBPL Onshore		Segment #3: Shoreline to Beta Pump Station		
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			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
3	Stress corrosion cracking	Age of pipe	29 Years	SCC specific DA	
3	Stress corrosion cracking	Operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)	SCC specific DA	
3	Stress corrosion cracking	Operating temperature	65 to 74 degrees	SCC specific DA	
3	Stress corrosion cracking	Distance from compressor station	NA	SCC specific DA	
3	Stress corrosion cracking	Coating type	Coal Tar enamel with 15 LBS felt	SCC specific DA	
3	Stress corrosion cracking	Past hydro static test information	NA	SCC specific DA	
3	**SCC Summary Comment:**	All of the following conditions must be present for SCC: (see ASME B31.8S, appendix section A3.3) 1) Operating stress greater than 60% SMYS 2) Operating temperature greater than 100 degrees F	**This segment does not meet the conditions of #1 and #3, therefore SCC is not a threat to this segment.**		
	Construction, Manufacturing,and Materials Threat Summary		**Yes this segment is considered a threat .**		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Pipe material	API 5LX Grade X52, DSA, Cold Expanded, Steel Pipe 0.500 and 0.375 WT	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Year of installtion	1980	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Manufacturing process	Normal. No cast iron pipe, no mechanically coupled pipe, no acetylene girth welds.	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Seam type	Seamless	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Joint factor	1.0 (195.106)	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Operating pressure history	System operates at steady state	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	MOP	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
4	Construction, Manufacturing, and Materials	% SMYS at MOP	31%		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Results from previous testing/inspection. [see 195.452(h)]	None found	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Leak and repair history.	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not needed, installed 1980	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy Crude Oil	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Pipe wall thickness (thicker walls give a better safety margin).	0.500 and 0.375	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Local environmental factors that could affect the pipeline (corrosivity of soil, subsidence, climatic)	subsidence	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	***ROW surveys cunducted more Freq.***
4	Construction, Manufacturing, and Materials	Time since the last internal inspection/pressure testing.	1 year and 5 months	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Previously discovered defects/anomalies, including type, growth rate, and size.	None to date	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

SPBPL Onshore | Segment #3: Shoreline to Beta Pump Station

SPBPL (CSFM # 0341)

Updated: Feb 18, 2009

Color	Meaning
Yellow	= unknown data, or unsat data
Blue	= no threat
Red	= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, **Rev #2009-1**

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
4	Construction, Manufacturing, and Materials	Operating stress levels in the pipeline. Exposure of pipeline to exceed MOP	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Physical support of the pipeline segment such as by a cable suspension bridge. Includes external loading and stress.	NA	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Elevation profile	0' at shoreline to Apx 15' at Beta Station	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Install new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Reduce operating stress level (% SMYS)	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Review and improve welding procedures	Approved welding procedures already in place.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct NDT inspection on welds	Original welds x-rayed and inspected	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct exposed pipe inspections reports and bellholes.	Inspections performed twice annually.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	**Construction, Manufacturing,and Materials Threat Summary**		**Yes considered a threat due to age of line.**		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
5	Third Party Damage Threat	Results from previous testing/inspection. [see 195.452(h)]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Leak and repair history.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipe wall thickness (thicker walls give a better safety margin).	0.500 and 0.375	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	3111 Bbls worst case scenario from integreted contingency plan	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Time since the last internal inspection/pressure testing.	1 Year and 5 Months	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Construction activity in the area.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [H.02.a]	Only using DOT Qualified company personnel for DOT task.	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Participating in one-call systems and monitoring "One Call" activity more closely. [H.02.a]	Yes, USA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If evidence of encroahment without monitoring, excavations or above gnd electrical survey per NACE RP-0502. [H.02.a]	Yes	ILI, pressure tests, exposed pipe reports	

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
5	Third Party Damage Threat	Improve line marking	Always open to improvements, none needed at this time	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Install optical electronic detection and/or sound detection system.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Increase depth of cover	None needed at this time	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Line relocation	Have related pipeline in 3 locations	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve public education	Meeting requirement See O&M procedure 3.03	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve Right-of-Way (ROW) Maintenance	Weekly ROW inspections	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	More frequent ROW inspections	When activity rises in area	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Mechanical pipe inspection	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Additional pipe wall thickness	Not needed	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline marker tape over pipeline	None	ILI, pressure tests, exposed pipe reports	
5	**Third Party Damage Threat Summary**		Yes this segment is considered a threat due to fact that third party damage is major cause of pipeline accidents nationwide.	ILI, pressure tests, exposed pipe reports	

SPBPL Onshore — Segment #3: Shoreline to Beta Pump Station

SPBPL (CSFM # 0341)

Updated: Feb 18, 2009

Colour	Meaning
Yellow	= unknown data, or unsat data
Light blue	= no threat
Red	= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
6	Incorrect Operations or Procedure Error Threat	Conduct self audits	Integrity program reviewed once per year. Audited by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Review and improve O&M procedures	Meets yearly requiremnts and been audited by agencies numerous times. Audited in by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Conduct training, or improve existing training	OQ trng in place.	Audits by agency, company or 3rd party	
6	**Incorrect Operations Threat Summary**		Yes this segment is considered a threat due to fact that Incorrect operations is a cause of pipeline accidents nationwide.	Audits by agency, company or 3rd party	
7	Equipment Threat	Leak and repair history.	NA	Repair of replace equip	
7	Equipment Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#	Repair of replace equip	
7	Equipment Threat	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	All standardized equipment used	Repair of replace equip	
7	Equipment Threat	Increase frequency of visual and mechanical inspections	NA	Repair of replace equip	
7	Equipment Threat	Improve or change design or materials	Always open to improvements, none needed	Repair of replace equip	
7	Equipment Threat	Review and improve O&M procedures	None needed at this time		
7	**Equipment Threat Summary**		Yes this segment is considered a threat due to fact equipment failures can be a a cause of pipeline accidents.		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Joint method (mechancial coupling, acetylene weld, arc weld)	All arc welded	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Topicgraphical and soil conditions (unstable slops, water crossings, water proximity, soil liquefactions susceptibility)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Earthquake fault	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Profile of ground of ground acceleration near fault zones (>0.2 g acceleration)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Depth of frost line	NA	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Year of installation	1980	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Pipe grade, diameter, wall thickness (internal stress calcs added to external loading, total stress not to excedd 100% SMYS)	API 5LX Grade X52, DSA, Cold Expanded, Steel Pipe 0.500 and 0.375 WT	O&M inspections	

SPBPL Onshore | Segment #3: Shoreline to Beta Pump Station

SPBPL (CSFM # 0341)

Updated: Feb 18, 2009

Legend	
(yellow)	= unknown data, or unsat data
(light blue)	= no threat
(red)	= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
8	**Natural Forces Damage threat summary**		Yes this segment is considered a threat due to being in a fault zone.	O&M inspections	
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Located in environmentally sensitive area.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	3111 as per ICP manual		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	High pressure shutdown set at 862# with ESD valves on both ends of the PL		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Relocate line	None		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install or improve computerized monitoring	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		

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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
9	**Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases Threat Summary**		**Yes this segment is considered a threat .**		
10	Environmental Impact	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
10	Environmental Impact	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
10	Environmental Impact	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	3111 Bbls worst case scenario from integreted contingency plan		
10	Environmental Impact	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP	PSH's set at 862#, PRV is set at 1100#Below MOP of 1152#		

	SPBPL Onshore	Segment #3: Shoreline to Beta Pump Station			
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet. Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
10	Environmental Impact	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
10	Environmental Impact	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
10	Environmental Impact	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	High pressure shutdown set at 862# with ESD valves on both ends of the PL		
10	Environmental Impact	Relocate line	None		
10	Environmental Impact	Install H2S sensors and/or fuel gas sensors	NA		
10	Environmental Impact	Install or improve computerized monitoring	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
10	Environmental Impact	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
10	Environmental Impact	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
10	Environmental Impact	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
10	Environmental Impact	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
10	Environmental Impact	Reduce operating stress level (% SMYS)	MOP is 1152 but NOP is Ap. 260-400 # Operating at 31% of SMYS		
10	**Environmental Impact Threat Summary**		**Yes this segment is considered a threat .**		
11	Property Damage	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
11	Property Damage	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
11	Property Damage	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	3111 Bbls worst case scenario from integreted contingency plan		
11	Property Damage	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100#Below MOP of 1152#		

	SPBPL Onshore		Segment #3: Shoreline to Beta Pump Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
11	Property Damage	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
11	Property Damage	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
11	Property Damage	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	High pressure shutdown set at 862# with ESD valves on both ends of the PL		
11	Property Damage	Relocate line	None		
11	Property Damage	Install H2S sensors and/or fuel gas sensors	NA		
11	Property Damage	Install or improve computerized monitoring	ATMOS Pipe Leak detection. Installed in 2001 and updated in 2008		
11	Property Damage	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
11	Property Damage	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
11	Property Damage	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
11	Property Damage	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
11	Property Damage	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		
11	**Property Damage Threat Summary**		**Yes this segment is considered a threat .**		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct training, or improve existing training	OQ training in place		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Reduce operating stress level (% SMYS)	MOP is 1152 (31% of SMYS) but NOP is Apx. 260-400 # (11% of SMYS)		

	SPBPL Onshore		Segment #3: Shoreline to Beta Pump Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
12	Alternate Modes of Operation Threat Summay		Yes this segment is considered a threat .		
13	Interactive Threat	Manufacturing defect activated by pressure cycling	Yes this segment is considered a threat .		
14	Interactive Threat	Corrosion accelerated by TPD	Yes this segment is considered a threat .		
15	Interactive Threat	Corrosion accelerated by outside force	Yes this segment is considered a threat .		
16	Other segment specific threats summary		None		

Beta Pump Station
SPBPL (CSFM # 0341)
Updated: Feb 18, 2009

Segment #: Beta Station

(yellow)	= unknown data, or unsat data
(blue)	= no threat
(red)	= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
1	External corrosion	Results from all previous testing/inspection integrity issues (smart pigs, pressure tests, ECDA, other). [see 195.452(h)]	All inspections, CP surveys, valve inspections and instrument testing performed with no malfuctions	ILI, pressure test, DA	
1	External corrosion	Leak and repair history	None	ILI, pressure test, DA	
1	External corrosion	Cathodic protection history and known corrosion or condition of pipeline. [see 195.452(g)]	CP survey history adequate, all readings above 850 mv criteria.	ILI, pressure test, DA	
1	External corrosion	Type, quality, and condition of coating (disbonded coating increases likilhood of corrosion)	Coal tar enamel coating shows no signs of disbondment	ILI, pressure test, DA	
1	External corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and	Installed in 1980	ILI, pressure test, DA	
1	External corrosion	Pipe wall thickness (thicker walls give a better safety margin).	Multiple – Pump Station	ILI, pressure test, DA	
1	External corrosion	Time since the last internal inspection/pressure testing.	NA	ILI, pressure test, DA	
1	External corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure test, DA	
1	External corrosion	Close interval survey	NA	ILI, pressure test, DA	
1	External corrosion	Open hole inspections/exposed pipe reports.	Exposed pipe report	ILI, pressure test, DA	
1	External corrosion	Install more CP test stations	NA ---	ILI, pressure test, DA	
1	External corrosion	Local environmental factors that could affect the pipeline (corrosivity of soil, MIC, etc.)	None to date	ILI, pressure test, DA	
1	External corrosion	Remote CP monitoring	CP survey annually	ILI, pressure test, DA	
1	External corrosion	Guided wave technology	None	ILI, pressure test, DA	
1	External corrosion	Fill casing voids with inert materials	None	ILI, pressure test, DA	
1	External corrosion	DCVG survey (coating holidays)	None	ILI, pressure test, DA	
1	External corrosion	Reduce operating stress level (% SMYS)	NA -	ILI, pressure test, DA	
1	External corrosion	Upgrade or change CP system design	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of CP survey readings and/or revised O&M procedures.	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not required at this time.	ILI, pressure test, DA	

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
1	External corrosion summary	Threat Yes/No	Yes it is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.		

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet. Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	Internal corrosion	Results from all previous testing/inspection integrity issues. [see 195.452(h)]	None found	ILI, pressure test, DA	
2	Internal corrosion	Leak and repair history.	No repairs do to internal corrosion	ILI, pressure test, DA	
2	Internal corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Const. in 1980		
2	Internal corrosion	Pipe wall thickness (thicker walls give a better safety margin).	Multiple -- Pump Station	ILI, pressure test, DA	
2	Internal corrosion	Time since the last internal inspection/pressure testing.	NA	ILI, pressure test, DA	
2	Internal corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	None discovered	ILI, pressure test, DA	
2	Internal corrosion	Fluid analysis and characteristics of product transported (corrosive properties, etc.).	Fluid analysis shows no corrosive properties.	ILI, pressure test, DA	
2	Internal corrosion	Corrosion monitoring program	Coupons show no corrosion. Corrosion inhibitor and biocide injected at recommended rates by Clariant	ILI, pressure test, DA	
2	Internal corrosion	Elevation profile	Level at 13'	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of integrity testing (*ILI, pressure test, DA, Other*)	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Increase wall thickness	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Install corrosion detection devices (coupons, probes, etc.)	Coupons already in place	ILI, pressure test, DA	
2	Internal corrosion	Change operating parameters (particularly pressure and flow velocity and especially periods where there is no flow)	Not needed but system operates at steady state when shipping.	ILI, pressure test, DA	
2	Internal corrosion	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as coupon monitoring, chemical injection, etc.	Only using DOT Qualified company personnel for DOT task.	ILI, pressure test, DA	
2	Internal corrosion	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of corrosion monitoring and/or revised O&M procedures	Not needed	ILI, pressure test, DA	

	Beta Pump Station		Segment #[illegible]: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	Internal corrosion	Reduce operating stress level (% SMYS)	NA -- Pump Station	ILI, pressure test, DA	
2	Internal corrosion	Run cleaning pig and/or cleaning fluid through the line.	Unpiggable	ILI, pressure test, DA	
2	Internal corrosion	Chemical injection for impurities	No	ILI, pressure test, DA	
2	Internal corrosion	Exposed pipe reports	Yes	ILI, pressure test, DA	
2	**Internal corrosion summary**	**Threat YES/NO**	**Yes is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.**		

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
3	Stress corrosion cracking	Age of pipe	29 Years	SCC specific DA	
3	Stress corrosion cracking	Operating stress level (% SMYS)	50.5% Max	SCC specific DA	
3	Stress corrosion cracking	Operating temperature	64 thru 74 degrees	SCC specific DA	
3	Stress corrosion cracking	Distance from compressor station	NA	SCC specific DA	
3	Stress corrosion cracking	Coating type	Paint and Coal Tar enamel with 15LBS felt	SCC specific DA	
3	Stress corrosion cracking	Past hydro static test information	NA	SCC specific DA	
3	**SCC Summary Comment:**	All of the following conditions must be present for SCC: (see ASME B31.8S, appendix section A3.3) 1) Operating stress greater than 60% SMYS 2) Operating temperature greater than 100 degrees F	**This segment does not meet the conditions of #1 and #3, therefore SCC is not a threat to this segment.**		
	Construction, Manufacturing,and Materials Threat Summary		**Yes this segment is considered a threat .**		

	Beta Pump Station		Segment #4: Beta Station		
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	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	*Construction, Manufacturing, and* Materials	*Pipe material*	ASTM A-106 Grade B Seamless Steel Pipe	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Year of installtion	1980	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Manufacturing process	Normal. No cast iron pipe, no mechanically coupled pipe, no acetylene girth welds.	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Seam type	Seamless	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Joint factor	1.0 (195.106)	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and *Materials*	Operating pressure history	6 thru 700#	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	MOP	NA		
4	Construction, Manufacturing, and Materials	% SMYS at MOP	50.5% Max		

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: *SPBPL Liquid IMP Threat Analysis & Data Worksheet. Rev #2009-1*				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Results from previous testing/inspection. [see 195.452(h)]	None found	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Leak and repair history.	No leaks. Repair to riser at splash zone (+13) due to Ext, Corr.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Paint above ground and Coal Tar Enamel with 15 LBS Felt below	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not needed, installed 1980	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy Crude Oil	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Pipe wall thickness (thicker walls give a better safety margin).	Multiple -- Pump Station	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Local environmental factors that could affect the pipeline. (corrosivity of soil, subsidence, climatic)	Wave action of ocean	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Time since the last internal inspection/pressure testing.	1 year and 5 months	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Previously discovered defects/anomalies, including type, growth rate, and size.	None to date	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Operating stress levels in the pipeline. Exposure of pipeline to exceed MOP	Facility completely protected with instrumentation to protect against over pressure	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Physical support of the pipeline segment such as by a cable suspension bridge. Includes external loading and stress.	Support clamps on entire Ellys Platform	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Elevation profile	Level at 13'	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Install new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Reduce operating stress level (% SMYS)	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Review and improve welding procedures	Approved welding procedures already in place.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct NDT inspection on welds	Original welds x-rayed and inspected	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct exposed pipe inspections reports and bellholes.	When exposed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	**Construction, Manufacturing,and Materials Threat Summary**		**Yes considered a threat due to age of line.**		

Beta Pump Station
SPBPL (CSFM # 0341)
Updated: Feb 18, 2009

Segment #4: Beta Station

Color	Meaning
Yellow	= unknown data, or unsat data
Light blue	= no threat
Red	= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet. Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
5	Third Party Damage Threat	Results from previous testing/inspection. [see 195.452(h)]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Leak and repair history.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	None due to TPD	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipe wall thickness (thicker walls give a better safety margin).	NA -- Has multiple	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Time since the last internal inspection/pressure testing.	NA -- Pump Station	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Facility completely protected with instrumentation to protect against over pressure	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Construction activity in the area.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [H.02.a]	Only using DOT Qualified company personnel for DOT task.	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Participating in one-call systems and monitoring "One Call" activity more closely. [H.02.a]	Yes -- USA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If evidence of encroahment without monitoring, excavations or above gnd electrical survey per NACE RP-0502. [H.02.a]	Always have personnel for excavation monitoring	ILI, pressure tests, exposed pipe reports	

	Beta Pump Station		Segment #1: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
5	Third Party Damage Threat	Improve line marking	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Install optical electronic detection and/or sound detection system.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Increase depth of cover	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Line relocation	NA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve public education	Meeting requirement See O&M procedure 3.03	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve Right-of-Way (ROW) Maintenance	NA-- Pump Station	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	More frequent ROW inspections	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Mechanical pipe inspection	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Additional pipe wall thickness	none	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline marker tape over pipeline	None	ILI, pressure tests, exposed pipe reports	
5	**Third Party Damage Threat Summary**		Yes this segment is considered a threat due to fact that third party damage is major cause of pipeline accidents nationwide.	ILI, pressure tests, exposed pipe reports	

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
6	Incorrect Operations or Procedure Error Threat	Conduct self audits	Integrity program reviewed once per year. Audited by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Review and improve O&M procedures	Meets yearly requiremnts and been audited by agencies numerous times. Audited in by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Conduct training, or improve existing training	OQ trng in place.	Audits by agency, company or 3rd party	
6	**Incorrect Operations Threat Summary**		Yes this segment is considered a threat due to fact that incorrect operations is a cause of pipeline accidents nationwide.	Audits by agency, company or 3rd party	
7	Equipment Threat	Leak and repair history.	No leaks or repair history	Repair of replace equip	
7	Equipment Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Facility completely protected with instrumentation to protect against over pressure	Repair of replace equip	
7	Equipment Threat	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	All standardized equipment used	Repair of replace equip	
7	Equipment Threat	Increase frequency of visual and mechanical inspections	Inspected daily	Repair of replace equip	
7	Equipment Threat	Improve or change design or materials	Always open to improvements, none needed	Repair of replace equip	
7	Equipment Threat	Review and improve O&M procedures	None needed at this time		
7	**Equipment Threat Summary**		Yes this segment is considered a threat due to fact equipment failures can be a a cause of pipeline accidents.		

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	*Joint method (mechancial coupling,* acetylene weld, arc weld)	All arc welded	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Topicgraphical and soil conditions (unstable slops, water crossings, water proximity, soil liquefactions susceptibility)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Earthquake fault	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Profile of ground of ground acceleration near fault zones (>0.2 g acceleration)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Depth of frost line	NA	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	**Year of installation**	1980	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Pipe grade, diameter, wall thickness (internal stress calcs added to external loading, total stress not to excedd 100% SMYS)	Pump Station, multiple types and size of pipe	O&M inspections	

	Beta Pump Station		Segment #4: Beta Station		
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	Updated: Feb 18, 2009		= no threat		
			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	**Natural Forces Damage threat summary**		Yes this segment is considered a threat due to being in a fault zone.	O&M inspections	
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Located in environmentally sensitive area.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	*Amount of product that could be* released (i.e., size of pipe, higher volume release if the pipe ruptures).	*10 Bbls as per ICP Annex H*		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Facility completely protected with instrumentation to protect against over pressure		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional *monitoring and/or significantly*	Facility has complete access for inspection		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	NA		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	Facility completely protected with instrumentation to protect against over pressure		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Relocate line	None		
9	*Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases*	*Install H2S sensors and/or fuel gas* sensors	*Not a high H2S facility*		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install or improve computerized monitoring	Already in place		

	Beta Pump Station		Segment #4: Beta Station		
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			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	NA		
9	**Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases Threat Summary**		Yes this segment is considered a threat .		
10	Environmental Impact	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
10	Environmental Impact	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
10	Environmental Impact	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		
10	Environmental Impact	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Facility completely protected with instrumentation to protect against over pressure		

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
10	Environmental Impact	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	Facility has complete access for inspection		
10	Environmental Impact	Reduce operating stress level (% SMYS)	NA		
10	Environmental Impact	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	Facility has MOV's for isolation of the facility if needed		
10	Environmental Impact	Relocate line	None		
10	Environmental Impact	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
10	Environmental Impact	Install or improve computerized monitoring	Already in place		
10	Environmental Impact	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
10	Environmental Impact	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
10	Environmental Impact	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
10	Environmental Impact	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
10	Environmental Impact	Reduce operating stress level (% SMYS)	NA		
10	**Environmental Impact Threat Summary**		Yes this segment is considered a threat .		
11	Property Damage	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
11	Property Damage	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
11	Property Damage	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		
11	Property Damage	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Facility completely protected with instrumentation to protect against over pressure		

	Beta Pump Station		Segment #?: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
11	Property Damage	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	Facility has complete access for inspection		
11	Property Damage	Reduce operating stress level (% SMYS)	NA		
11	Property Damage	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors	Facility has MOV's for isolation of the facility if needed		
11	Property Damage	Relocate line	None		
11	Property Damage	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
11	Property Damage	Install or improve computerized monitoring	NA		
11	Property Damage	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
11	Property Damage	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
11	Property Damage	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
11	Property Damage	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
11	Property Damage	Reduce operating stress level (% SMYS)	Not needed		
11	**Property Damage Threat Summary**		Yes this segment is considered a threat .		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Facility completely protected with instrumentation to protect against over pressure		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	*Conduct training, or improve existing training*	*OQ training in place*		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Reduce operating stress level (% SMYS)	Not needed		

	Beta Pump Station		Segment #4: Beta Station		
	SPBPL (CSFM # 0341)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= *no threat*		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
12	**Alternate Modes of Operation Threat Summay**		Yes this segment is considered a threat .		
13	**Interactive Threat**	**Manufacturing defect activated by pressure cycling**	Yes this segment is considered a threat .		Laminations identified in 9-07 ILI run. Classified as A-B-C. all listed as B's. (non-critical)
14	**Interactive Threat**	Corrosion accelerated by TPD	Yes this segment is considered a threat .		
15	**Interactive Threat**	Corrosion accelerated by outside force	Yes this segment is considered a threat .		
16	**Other segment specific threats summary**		**None**		

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
	Beta (CSFM # 1017)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
1	External corrosion	Results from all previous testing/inspection integrity issues (smart pigs, pressure tests, ECDA, other). [see 195.452(h)]	Line OOS since 1995. Last hydro test was 2000. Line is unpiggable	ILI, pressure test, DA	
1	External corrosion	Leak and repair history.	None	ILI, pressure test, DA	
1	External corrosion	Cathodic protection history and known corrosion or condition of pipeline. [see 195.452(g)]	CP survey history adequate, all readings above 850 mv criteria.	ILI, pressure test, DA	
1	External corrosion	Type, quality, and condition of coating (disbonded coating increases likilhood of corrosion)	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	ILI, pressure test, DA	
1	External corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and	Installed in 1980	ILI, pressure test, DA	
1	External corrosion	Pipe wall thickness (thicker walls give a better safety margin).	0.438	ILI, pressure test, DA	
1	External corrosion	Time since the last internal inspection/pressure testing.	Jun-05	ILI, pressure test, DA	
1	External corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure test, DA	
1	*External corrosion*	*Close interval survey*	*None*	*ILI, pressure test, DA*	
1	External corrosion	Open hole inspections/exposed pipe reports.	Yes, always looked like new	ILI, pressure test, DA	
1	External corrosion	Install more CP test stations	None needed at this time	ILI, pressure test, DA	
1	External corrosion	Local environmental factors that could affect the pipeline (corrosivity of soil, MIC, etc.)	None needed at this time	ILI, pressure test, DA	
1	External corrosion	Remote CP monitoring	CP surveys performed annually	ILI, pressure test, DA	
1	External corrosion	Guided wave technology	None	ILI, pressure test, DA	
1	External corrosion	Fill casing voids with inert materials	None	ILI, pressure test, DA	
1	External corrosion	DCVG survey (coating holidays)	None	ILI, pressure test, DA	
1	External corrosion	Reduce operating stress level (% SMYS)	NA- Line OOS will hydrotest if brought back into service	ILI, pressure test, DA	
1	External corrosion	Upgrade or change CP system design	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of CP survey readings and/or revised O&M procedures.	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not required at this time.	ILI, pressure test, DA	

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
	Beta (CSFM # 1017)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
1	External corrosion summary	Threat Yes/No	Yes it is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.		

Beta Delivery line # 1

Beta (CSFM # 1017)

Updated: Feb 18, 2009

Segment #5: Beta Shipping Line # 1

= unknown data, or unsat data

= no threat

= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
2	Internal corrosion	Results from all previous testing/inspection integrity issues. [see 195.452(h)]	None found	ILI, pressure test, DA	
2	*Internal corrosion*	*Leak and repair history.*	*No repairs due to internal corrosion*	ILI, pressure test, DA	
2	Internal corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Const. in 1980		
2	Internal corrosion	Pipe wall thickness (thicker walls give a better safety margin).	0.438	ILI, pressure test, DA	
2	Internal corrosion	Time since the last internal inspection/pressure testing.	9 years	ILI, pressure test, DA	
2	Internal corrosion	Previously discovered *defects/anomalies, including type,* growth rate, and size.	None discovered	ILI, pressure test, DA	
2	Internal corrosion	Fluid analysis and characteristics of product transported (corrosive properties, etc.).	Fluid analysis shows no corrosive properties.	ILI, pressure test, DA	
2	Internal corrosion	Corrosion monitoring program	Coupons show no corrosion. Corrosion inhibitor and biocide injected at recommended rates by Clariant	ILI, pressure test, DA	
2	Internal corrosion	Elevation profile	level	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of integrity testing *(ILI, pressure test, DA, Other)*	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Increase wall thickness	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Install corrosion detection devices (coupons, probes, etc.)	None	ILI, pressure test, DA	
2	Internal corrosion	Change operating parameters (particularly pressure and flow velocity and especially periods where there is no flow)	NA Line OOS	ILI, pressure test, DA	
2	Internal corrosion	Using qualified personnel for work *an operator is conducting that could* adversely affect the integrity of a covered segment, such as coupon monitoring, chemical injection, etc.	Only using DOT Qualified company *personnel for DOT task.*	ILI, pressure test, DA	
2	Internal corrosion	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional *P&M in HCA areas. [H.02.a]*	None	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of corrosion monitoring and/or revised O&M procedures.	Not needed	ILI, pressure test, DA	

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
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	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	Internal corrosion	Reduce operating stress level (% SMYS)	NA- Line OOS will hydrotest if brought back into service	ILI, pressure test, DA	
2	Internal corrosion	Run cleaning pig and/or cleaning fluid through the line.	Unpiggable	ILI, pressure test, DA	
2	Internal corrosion	Chemical injection for impurities	None	ILI, pressure test, DA	
2	Internal corrosion	Exposed pipe reports	None	ILI, pressure test, DA	
2	**Internal corrosion summary**	**Threat YES/NO**	**Yes is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.**		

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
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	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
3	Stress corrosion cracking	Age of pipe	29 Years	SCC specific DA	
3	Stress corrosion cracking	Operating stress level (% SMYS)	NA- Line OOS will hydrotest if brought back into service	SCC specific DA	
3	Stress corrosion cracking	Operating temperature	65 to 74 degrees	SCC specific DA	
3	Stress corrosion cracking	Distance from compressor station	NA	SCC specific DA	
3	Stress corrosion cracking	Coating type	Coal Tar enamel with 15 LBS felt	SCC specific DA	
3	Stress corrosion cracking	Past hydro static test information	NA	SCC specific DA	
3	**SCC Summary Comment:**	All of the following conditions must be present for SCC: (see ASME B31.8S, appendix section A3.3) 1) Operating stress greater than 60% SMYS 2) Operating temperature greater than 100 degrees F	**This segment does not meet the conditions of #1 and #3, therefore SCC is not a threat to this segment.**		
	Construction, Manufacturing,and Materials Threat Summary		**Yes this segment is considered a threat .**		

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Pipe material	Mild Steel API 5L GR B. 0.438 WT	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Year of installtion	1980	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Manufacturing process	Normal. No cast iron pipe, no mechanically coupled pipe, no acetylene girth welds.	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Seam type	Seamless	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Joint factor	1.0 (195.106)	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Operating pressure history	Pipeline is OOS	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	MOP	NA- Line OOS will hydrotest if brought back into service		
4	Construction, Manufacturing, and Materials	% SMYS at MOP	NA- Line OOS will hydrotest if brought back into service		

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
	Beta (CSFM # 1017)		= unknown data, or unset data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Results from previous testing/inspection. [see 195.452(h)]	None found	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Leak and repair history.	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not needed, installed 1980	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy Crude Oil	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Pipe wall thickness (thicker walls give a better safety margin).	0.438	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Local environmental factors that could affect the pipeline (corrosivity of soil, subsidence, climatic)	subsidence	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	***ROW surveys cunducted more Freq.***
4	Construction, Manufacturing, and Materials	Time since the last internal inspection/pressure testing.	9 years	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Previously discovered defects/anomalies, including type, growth rate, and size.	None to date	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
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Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Operating stress levels in the pipeline. Exposure of pipeline to exceed MOP	PSH's set at 500#, PRV is set at 1400#	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Physical support of the pipeline segment such as by a cable suspension bridge. Includes external loading and stress.	NA	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Elevation profile	Level	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Install new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, *Manufacturing, and* Materials	*Reduce operating stress level (%* SMYS)	*Not Needed*	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Review and improve welding procedures	Approved welding procedures already in place.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct NDT inspection on welds	Original welds x-rayed and inspected	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct exposed pipe inspections reports and bellholes.	Inspections performed twice annually.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
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			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	**Construction, Manufacturing,and Materials Threat Summary**		**Yes considered a threat due to age of line.**		

Beta Delivery line # 1 — Segment #5: Beta Shipping Line # 1

Beta (CSFM # 1017)

Updated: Feb 18, 2009

= unknown data, or unsat data
= no threat
= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet. Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
5	Third Party Damage Threat	Results from previous testing/inspection. [see 195.452(h)]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Leak and repair history.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipe wall thickness (thicker walls give a better safety margin).	0.438	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Time since the last internal inspection/pressure testing.	9 years	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Pipeline OOS until further notice	ILI, pressure tests, exposed pipe reports	***Will hydrotest before bringing back into service***
5	Third Party Damage Threat	Construction activity in the area.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [H.02.a]	Only using DOT Qualified company personnel for DOT task.	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Participating in one-call systems and monitoring "One Call" activity more closely. [H.02.a]	Yes, USA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If evidence of encroahment without monitoring, excavations or above gnd electrical survey per NACE RP-0502. [H.02.a]	Yes	ILI, pressure tests, exposed pipe reports	

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
	Beta (CSFM # 1017)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
5	Third Party Damage Threat	Improve line marking	Always open to improvements, none needed at this time	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Install optical electronic detection and/or sound detection system.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Increase depth of cover	None needed at this time	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Line relocation	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve public education	Meeting requirement See O&M procedure 3.03	ILI, pressure tests, exposed pipe reports	
5	*Third Party Damage Threat*	*Improve Right-of-Way (ROW)* Maintenance	Weekly ROW inspections	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	More frequent ROW inspections	When activity rises in area	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Mechanical pipe inspection	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Additional pipe wall thickness	Not needed	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline marker tape over pipeline	None	ILI, pressure tests, exposed pipe reports	
5	**Third Party Damage Threat Summary**		**Yes this segment is considered a threat due to fact that third party damage is major cause of pipeline accidents nationwide.**	ILI, pressure tests, exposed pipe reports	

Beta Delivery line # 1

Segment #5: Beta Shipping Line # 1

Beta (CSFM # 1017)

Updated: Feb 18, 2009

(yellow)	= unknown data, or unsat data
(light blue)	= no threat
(red)	= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet. Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
6	Incorrect Operations or Procedure Error Threat	Conduct self audits	Integrity program reviewed once per year. Audited by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Review and improve O&M procedures	Meets yearly requiremnts and been audited by agencies numerous times. Audited in by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Conduct training, or improve existing training	OQ trng in place.	Audits by agency, company or 3rd party	
6	**Incorrect Operations Threat Summary**		**Yes this segment is considered a threat due to fact that incorrect operations is a cause of pipeline accidents nationwide.**	Audits by agency, company or 3rd party	
7	Equipment Threat	Leak and repair history.	NA	Repair of replace equip	
7	Equipment Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Pipeline OOS until further notice	Repair of replace equip	***Will hydrotest before bringing back into service***
7	Equipment Threat	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	All standardized equipment used	Repair of replace equip	
7	Equipment Threat	Increase frequency of visual and mechanical inspections	NA	Repair of replace equip	
7	Equipment Threat	Improve or change design or materials	Always open to improvements, none needed at this time	Repair of replace equip	
7	Equipment Threat	Review and improve O&M procedures	None needed at this time		
7	**Equipment Threat Summary**		**Yes this segment is considered a threat due to fact equipment failures can be a a cause of pipeline accidents.**		

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
	Beta (CSFM # 1017)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Joint method (mechancial coupling, acetylene weld, arc weld)	All arc welded	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Topicgraphical and soil conditions (unstable slops, water crossings, water proximity, soil liquefactions susceptibility)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Earthquake fault	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Profile of ground of ground acceleration near fault zones (>0.2 g acceleration)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Depth of frost line	NA	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Year of installation	1980	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Pipe grade, diameter, wall thickness (internal stress calcs added to external loading, total stress not to excedd 100% SMYS)	Mild Steel API 5L GR B. 0.438 WT	O&M inspections	

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
	Beta (CSFM # 1017)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	**Natural Forces Damage threat summary**		Yes this segment is considered a threat due to being in a fault zone.	O&M inspections	
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Located in environmentally sensitive area.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Pipeline OOS until further notice		*Will hydrotest before bringing back into service*
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	None		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	NA, Line OOS		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	Will install if pipeline brought back into service		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Relocate line	None		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install or improve computerized monitoring	None installed due to line being OOS		

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
	Beta (CSFM # 1017)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	NA due to line being OOS		
9	**Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases Threat Summary**		**Yes this segment is considered a threat .**		
10	Environmental Impact	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
10	Environmental Impact	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
10	*Environmental Impact*	*Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).*	10 Bbls *as per* ICP Annex H		
10	Environmental Impact	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Pipeline OOS until further notice		

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
	Beta (CSFM # 1017)	(yellow)	= unknown data, or unsat data		
	Updated: Feb 18, 2009	(blue)	= no threat		
		(red)	= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
10	Environmental Impact	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	None installed due to line being OOS		
10	Environmental Impact	Reduce operating stress level (% SMYS)	NA due to line being OOS		
10	Environmental Impact	Install automatic shut-off and/or remote control valves. See protocol *H.07.a for factors.*	NA due to line being OOS		
10	Environmental Impact	Relocate line	None		
10	Environmental Impact	Install H2S sensors and/or fuel gas sensors	NA		
10	Environmental Impact	Install or improve computerized monitoring	None installed due to line being OOS		
10	Environmental Impact	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
10	Environmental Impact	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
10	Environmental Impact	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
10	Environmental Impact	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
10	Environmental Impact	Reduce operating stress level (% SMYS)	Pipeline OOS until further notice		
10	**Environmental Impact Threat Summary**		Yes this segment is considered a threat .		
11	Property Damage	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
11	Property Damage	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
11	Property Damage	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		
11	Property Damage	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	NA due to line being OOS		

Beta Delivery line # 1 | Segment #5: Beta Shipping Line # 1

Beta (CSFM # 1017)

Updated: Feb 18, 2009

(yellow)	= unknown data, or unsat data
(blue)	= no threat
(red)	= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
11	Property Damage	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	None installed due to line being OOS		
11	Property Damage	Reduce operating stress level (% SMYS)	NA due to line being OOS		
11	Property Damage	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	NA due to line being OOS		
11	Property Damage	Relocate line	None		
11	Property Damage	Install H2S sensors and/or fuel gas sensors	NA		
11	Property Damage	Install or improve computerized monitoring	None installed due to line being OOS		
11	Property Damage	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
11	Property Damage	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
11	Property Damage	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
11	Property Damage	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
11	Property Damage	Reduce operating stress level (% SMYS)	NA due to line being OOS		
11	**Property Damage Threat Summary**		Yes this segment is considered a threat .		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 862#, PRV is set at 1100# Below MOP of 1152#		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct training, or improve existing training	OQ training in place		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Reduce operating stress level (% SMYS)	NA due to line being OOS		

	Beta Delivery line # 1	Segment #5: Beta Shipping Line # 1			
	Beta (CSFM # 1017)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
12	Alternate Modes of Operation Threat Summay		Yes this segment is considered a threat .		
13	Interactive Threat	Manufacturing defect activated by pressure cycling	Yes this segment is considered a threat .		
14	Interactive Threat	Corrosion accelerated by TPD	Yes this segment is considered a threat .		
15	Interactive Threat	Corrosion accelerated by outside force	Yes this segment is considered a threat .		
16	Other segment specific threats summary		None		

	Beta Delivery line # 2				
	Beta (CSFM # 1018)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
1	External corrosion	Results from all previous testing/inspection integrity issues (smart pigs, pressure tests, ECDA, other). [see 195.452(h)]	Line successfully hydrotested to 1800# on 4-07	ILI, pressure test, DA	
1	External corrosion	Leak and repair history.	None	ILI, pressure test, DA	
1	External corrosion	Cathodic protection history and known corrosion or condition of pipeline. [see 195.452(g)]	CP survey history adequate, all readings above 850 mv criteria.	ILI, pressure test, DA	
1	External corrosion	Type, quality, and condition of coating (disbonded coating increases likilihood of corrosion)	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	ILI, pressure test, DA	
1	External corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Installed in 1980	ILI, pressure test, DA	
1	External corrosion	Pipe wall thickness (thicker walls give a better safety margin).	0.438	ILI, pressure test, DA	
1	External corrosion	Time since the last internal inspection/pressure testing.	22 months	ILI, pressure test, DA	
1	External corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure test, DA	
1	External corrosion	Close interval survey	None	ILI, pressure test, DA	
1	External corrosion	Open hole inspections/exposed pipe reports.	Yes, always looked like new	ILI, pressure test, DA	
1	External corrosion	Install more CP test stations	None needed at this time	ILI, pressure test, DA	
1	External corrosion	Local environmental factors that could affect the pipeline (corrosivity of soil, MIC, etc.)	None needed at this time	ILI, pressure test, DA	
1	External corrosion	Remote CP monitoring	CP surveys performed annually	ILI, pressure test, DA	
1	External corrosion	Guided wave technology	None	ILI, pressure test, DA	
1	External corrosion	Fill casing voids with inert materials	None	ILI, pressure test, DA	
1	External corrosion	DCVG survey (coating holidays)	None	ILI, pressure test, DA	
1	External corrosion	Reduce operating stress level (% SMYS)	NA- Line OOS will hydrotest if brought back into service	ILI, pressure test, DA	
1	External corrosion	Upgrade or change CP system design	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of CP survey readings and/or revised O&M procedures.	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not required at this time.	ILI, pressure test, DA	

Segment # 6.[illegible]a Shipping Line # 2

1	External corrosion summary	Threat Yes/No	Yes it is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.		

Segment # 6,[illegible]a Shipping Line # 2

2	Internal corrosion	Results from all previous testing/inspection integrity issues. [see 195.452(h)]	None found	ILI, pressure test, DA	
2	Internal corrosion	Leak and repair history.	No repairs due to internal corrosion	ILI, pressure test, DA	
2	Internal corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Const. in 1980		
2	Internal corrosion	Pipe wall thickness (thicker walls give a better safety margin).	0.438	ILI, pressure test, DA	
2	Internal corrosion	Time since the last internal inspection/pressure testing.	22 months	ILI, pressure test, DA	
2	Internal corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure test, DA	
2	Internal corrosion	Fluid analysis and characteristics of product transported (corrosive properties, etc.).	None	ILI, pressure test, DA	
2	Internal corrosion	Corrosion monitoring program	Yes, always looked like new	ILI, pressure test, DA	
2	Internal corrosion	Elevation profile	level	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Increase wall thickness	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Install corrosion detection devices (coupons, probes, etc.)	None	ILI, pressure test, DA	
2	Internal corrosion	Change operating parameters (particularly pressure and flow velocity and especially periods where there is no flow)	Not needed	ILI, pressure test, DA	
2	Internal corrosion	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as coupon monitoring, chemical injection, etc.	Only using DOT Qualified company personnel for DOT task.	ILI, pressure test, DA	
2	Internal corrosion	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of corrosion monitoring and/or revised O&M procedures.	Not needed	ILI, pressure test, DA	
2	Internal corrosion	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#	ILI, pressure test, DA	

2	Internal corrosion	Run cleaning pig and/or cleaning fluid through the line.	Unpiggable	ILI, pressure test, DA	
2	Internal corrosion	Chemical injection for impurities	None	ILI, pressure test, DA	
2	Internal corrosion	Exposed pipe reports	None	ILI, pressure test, DA	
2	**Internal corrosion summary**	**Threat YES/NO**	**Yes is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.**		

3	Stress corrosion cracking	Age of pipe	29 Years	SCC specific DA	
3	Stress corrosion cracking	Operating stress level (% SMYS)	50.50%	SCC specific DA	
3	Stress corrosion cracking	Operating temperature	65 to 74 degrees	SCC specific DA	
3	Stress corrosion cracking	Distance from compressor station	NA	SCC specific DA	
3	Stress corrosion cracking	Coating type	Coal Tar enamel with 15 LBS felt	SCC specific DA	
3	Stress corrosion cracking	Past hydro static test information	NA	SCC specific DA	
3	**SCC Summary Comment:**	All of the following conditions must be present for SCC: (see ASME B31.8S, appendix section A3.3) 1) Operating stress greater than 60% SMYS 2) Operating temperature greater than 100 degrees F	**This segment does not meet the conditions of #1 and #3, therefore SCC is not a threat to this segment.**		
	Construction, Manufacturing,and Materials Threat Summary		**Yes this segment is considered a threat .**		

4	Construction, Manufacturing, and Materials	Pipe material	Mild Steel API 5L GR B. 0.438 WT	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Year of installtion	1980	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Manufacturing process	Normal. No cast iron pipe, no mechanically coupled pipe, no acetylene girth welds.	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Seam type	Seamless	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Joint factor	1.0 (195.106)	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Operating pressure history	Never operated above 700# or 24.5% of SMYS	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	MOP	1440		
4	Construction, Manufacturing, and Materials	% SMYS at MOP	50.50%		

4	Construction, Manufacturing, and Materials	Results from previous testing/inspection. [see 195.452(h)]	None found	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Leak and repair history.	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not needed, installed 1980	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy Crude Oil	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Pipe wall thickness (thicker walls give a better safety margin).	0.438	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Local environmental factors that could affect the pipeline (corrosivity of soil, subsidence, climatic)	subsidence	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	***ROW surveys cunducted more Freq.***
4	Construction, Manufacturing, and Materials	Time since the last internal inspection/pressure testing.	22 months	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Previously discovered defects/anomalies, including type, growth rate, and size.	None to date	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

4	Construction, Manufacturing, and Materials	Operating stress levels in the pipeline. Exposure of pipeline to exceed MOP	PSH's set at 700#, PRV is set at 1400#	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	***PSH set at 700# at the request of Crimson PL***
4	Construction, Manufacturing, and Materials	Physical support of the pipeline segment such as by a cable suspension bridge. Includes external loading and stress.	NA	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Elevation profile	Level	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Install new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Reduce operating stress level (% SMYS)	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Review and improve welding procedures	Approved welding procedures already in place.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct NDT inspection on welds	Original welds x-rayed and inspected	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct exposed pipe inspections reports and bellholes.	Inspections performed twice annually.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

4	Construction, Manufacturing,and Materials Threat Summary		Yes considered a threat due to age of line.		

5	Third Party Damage Threat	Results from previous testing/inspection. [see 195.452(h)]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Leak and repair history.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipe wall thickness (thicker walls give a better safety margin).	0.438	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Time since the last internal inspection/pressure testing.	22 months	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline design criteria and operating stress levels in the pipeline. *Exposure of pipeline to exceed MOP.*	PSH's set at 700#, PRV is set at 1400#	ILI, pressure tests, exposed pipe reports	***PSH set at 700# at the request of Crimson PL***
5	Third Party Damage Threat	Construction activity in the area.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [H.02.a]	Only using DOT Qualified company personnel for DOT task.	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Participating in one-call systems and monitoring "One Call" activity more closely. [H.02.a]	Yes, USA	ILI, pressure tests, exposed pipe reports	

5	Third Party Damage Threat	Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If evidence of encroahment without monitoring, excavations or above gnd electrical survey per NACE RP-0502. [H.02.a]	Yes	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve line marking	Always open to improvements, none needed at this time	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Install optical electronic detection and/or sound detection system.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Increase depth of cover	None needed at this time	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Line relocation	none	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve public education	Meeting requirement See O&M procedure 3.03	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve Right-of-Way (ROW) Maintenance	Weekly ROW inspections	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	More frequent ROW inspections	When activity rises in area	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Mechanical pipe inspection	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Additional pipe wall thickness	Not needed	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline marker tape over pipeline	None	ILI, pressure tests, exposed pipe reports	
5	**Third Party Damage Threat Summary**		**Yes this segment is considered a threat due to fact that third party damage is major cause of pipeline accidents nationwide.**	ILI, pressure tests, exposed pipe reports	

6	Incorrect Operations or Procedure Error Threat	Conduct self audits	Integrity program reviewed once per year. Audited by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Review and improve O&M procedures	Meets yearly requiremnts and been audited by agencies numerous times. Audited in by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Conduct training, or improve existing training	OQ trng in place.	Audits by agency, company or 3rd party	
6	**Incorrect Operations Threat Summary**		**Yes this segment is considered a threat due to fact that incorrect operations is a cause of pipeline accidents nationwide.**	Audits by agency, company or 3rd party	
7	Equipment Threat	Leak and repair history.	NA	Repair of replace equip	
7	Equipment Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 700#, PRV is set at 1400#	Repair of replace equip	***PSH set at 700# at the request of Crimson PL***
7	Equipment Threat	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	All standardized equipment used	Repair of replace equip	
7	Equipment Threat	Increase frequency of visual and mechanical inspections	NA	Repair of replace equip	
7	Equipment Threat	Improve or change design or materials	Always open to improvements, none needed	Repair of replace equip	
7	Equipment Threat	Review and improve O&M procedures	None needed at this time		
7	**Equipment Threat Summary**		**Yes this segment is considered a threat due to fact equipment failures can be a a cause of pipeline accidents.**		

8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Joint method (mechancial coupling, acetylene weld, arc weld)	All arc welded	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Topicgraphical and soil conditions (unstable slops, water crossings, water proximity, soil liquefactions susceptibility)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Earthquake fault	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Profile of ground of ground acceleration near fault zones (>0.2 g acceleration)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Depth of frost line	NA	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Year of installation	1980	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Pipe grade, diameter, wall thickness (internal stress calcs added to external loading, total stress not to exceed 100% SMYS)	Mild Steel API 5L GR B. 0.438 WT	O&M inspections	
8	**Natural Forces Damage threat summary**		Yes this segment is considered a threat due to being in a fault zone.	O&M inspections	

9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Located in environmentally sensitive area.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat)	Heavy crude Oil		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 700#, PRV is set at 1440#		***PSH set at 700# at the request of Crimson PL***
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	None		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	Line equiped with remote controlled MOV		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Relocate line	None		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		

9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install or improve computerized monitoring	*Already in place*		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
9	**Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases Threat Summary**		**Yes this segment is considered a threat .**		
10	Environmental Impact	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
10	Environmental Impact	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
10	Environmental Impact	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		
10	Environmental Impact	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
10	Environmental Impact	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	Pipeline is in streets making monitoring very easy		
10	Environmental Impact	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		

10	Environmental Impact	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	Line equiped with remote controlled MOV		
10	Environmental Impact	Relocate line	None		
10	Environmental Impact	Install H2S sensors and/or fuel gas sensors	NA		
10	Environmental Impact	Install or improve computerized monitoring	Already in place		
10	Environmental Impact	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
10	Environmental Impact	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
10	Environmental Impact	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
10	Environmental Impact	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
10	Environmental Impact	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
10	**Environmental Impact Threat Summary**		**Yes this segment is considered a threat .**		
11	Property Damage	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
11	Property Damage	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
11	Property Damage	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		

11	Property Damage	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	50.5% of SMYS at MOP of 1440#		
11	Property Damage	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	Pipeline is in streets making monitoring very easy		
11	Property Damage	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
11	Property Damage	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	Line equiped with remote controlled MOV		
11	Property Damage	Relocate line	None		
11	Property Damage	Install H2S sensors and/or fuel gas sensors	NA		
11	Property Damage	Install or improve computerized monitoring	Already in place		
11	Property Damage	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
11	Property Damage	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
11	Property Damage	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
11	Property Damage	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
11	Property Damage	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
11	**Property Damage Threat Summary**		**Yes this segment is considered a threat .**		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		

12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct training, or improve existing training	OQ training in place		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
12	**Alternate Modes of Operation Threat Summay**		**Yes this segment is considered a threat .**		
13	**Interactive Threat**	**Manufacturing defect activated by pressure cycling**	**Yes this segment is considered a threat .**		
14	**Interactive Threat**	**Corrosion accelerated by TPD**	**Yes this segment is considered a threat .**		
15	**Interactive Threat**	**Corrosion accelerated by outside force**	**Yes this segment is considered a threat .**		
16	**Other segment specific threats summary**		**None**		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
1	External corrosion	Results from all previous testing/inspection integrity issues (smart pigs, pressure tests, ECDA, other). [see 195.452(h)]	Pipeline had an ILI with a MFL tool in 7-07	ILI, pressure test, DA	
1	External corrosion	Leak and repair history.	None	ILI, pressure test, DA	
1	External corrosion	Cathodic protection history and known corrosion or condition of pipeline. [see 195.452(g)]	CP survey history adequate, all readings above 850 mv criteria.	ILI, pressure test, DA	
1	External corrosion	Type, quality, and condition of coating (disbonded coating increases likilihood of corrosion)	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	ILI, pressure test, DA	
1	External corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and	Installed in 1980	ILI, pressure test, DA	
1	External corrosion	Pipe wall thickness (thicker walls give a better safety margin).	0.438	ILI, pressure test, DA	
1	External corrosion	Time since the last internal inspection/pressure testing.	20 Months	ILI, pressure test, DA	
1	External corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure test, DA	
1	External corrosion	Close interval survey	None	ILI, pressure test, DA	
1	External corrosion	Open hole inspections/exposed pipe reports.	Yes, always looked like new	ILI, pressure test, DA	
1	External corrosion	Install more CP test stations	None needed at this time	ILI, pressure test, DA	
1	External corrosion	Local environmental factors that could affect the pipeline (corrosivity of soil, MIC, etc.)	None needed at this time	ILI, pressure test, DA	
1	External corrosion	Remote CP monitoring	CP surveys performed annually	ILI, pressure test, DA	
1	External corrosion	Guided wave technology	None	ILI, pressure test, DA	
1	External corrosion	Fill casing voids with inert materials	None	ILI, pressure test, DA	
1	External corrosion	DCVG survey (coating holidays)	None	ILI, pressure test, DA	
1	External corrosion	Reduce operating stress level (% SMYS)	NA- Line OOS will hydrotest if brought back into service	ILI, pressure test, DA	
1	External corrosion	Upgrade or change CP system design	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of CP survey readings and/or revised O&M procedures.	Not required at this time.	ILI, pressure test, DA	
1	External corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not required at this time.	ILI, pressure test, DA	

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
1	External corrosion summary	Threat Yes/No	Yes it is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	Internal corrosion	Results from all previous testing/inspection integrity issues. [see 195.452(h)]	None found	ILI, pressure test, DA	
2	Internal corrosion	Leak and repair history.	No repairs due to internal corrosion	ILI, pressure test, DA	
2	Internal corrosion	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Const. in 1980		
2	Internal corrosion	Pipe wall thickness (thicker walls give a better safety margin).	0.438	ILI, pressure test, DA	
2	Internal corrosion	Time since the last internal inspection/pressure testing.	20 months	ILI, pressure test, DA	
2	Internal corrosion	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure test, DA	
2	Internal corrosion	Fluid analysis and characteristics of product transported (corrosive properties, etc.).	None	ILI, pressure test, DA	
2	Internal corrosion	Corrosion monitoring program	Yes, always looked like new	ILI, pressure test, DA	
2	Internal corrosion	Elevation profile	level	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of integrity testing (ILI, pressure test, DA, Other)	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Increase wall thickness	Not needed.	ILI, pressure test, DA	
2	Internal corrosion	Install corrosion detection devices (coupons, probes, etc.)	None	ILI, pressure test, DA	
2	Internal corrosion	Change operating parameters (particularly pressure and flow velocity and especially periods where there is no flow)	Not needed	ILI, pressure test, DA	
2	Internal corrosion	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as coupon monitoring, chemical injection, etc.	Only using DOT Qualified company personnel for DOT task.	ILI, pressure test, DA	
2	Internal corrosion	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure test, DA	
2	Internal corrosion	Increase frequency of corrosion monitoring and/or revised O&M procedures.	Not needed	ILI, pressure test, DA	
2	Internal corrosion	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#	ILI, pressure test, DA	

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
2	Internal corrosion	Run cleaning pig and/or cleaning fluid through the line.	Unpiggable	ILI, pressure test, DA	
2	Internal corrosion	Chemical injection for impurities	None	ILI, pressure test, DA	
2	Internal corrosion	Exposed pipe reports	None	ILI, pressure test, DA	
2	**Internal corrosion summary**	**Threat YES/NO**	**Yes is considered a threat due to fact that corrosion is second cause of pipeline accidents nationwide.**		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unset data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
3	Stress corrosion cracking	Age of pipe	29 Years	SCC specific DA	
3	Stress corrosion cracking	Operating stress level (% SMYS)	50.50%	SCC specific DA	
3	Stress corrosion cracking	Operating temperature	65 to 74 degrees	SCC specific DA	
3	Stress corrosion cracking	Distance from compressor station	NA	SCC specific DA	
3	Stress corrosion cracking	Coating type	Coal Tar enamel with 15 LBS felt	SCC specific DA	
3	Stress corrosion cracking	Past hydro static test information	NA	SCC specific DA	
3	**SCC Summary Comment:**	All of the following conditions must be present for SCC: (see ASME B31.8S, appendix section A3.3) 1) Operating stress greater than 60% SMYS 2) Operating temperature greater than 100 degrees F	**This segment does not meet the conditions of #1 and #3, therefore SCC is not a threat to this segment.**		
	Construction, Manufacturing,and Materials Threat Summary		**Yes this segment is considered a threat .**		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Pipe material	Mild Steel API 5L GR B. 0.438 WT	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Year of installtion	1980	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Manufacturing process	Normal. No cast iron pipe, no mechanically coupled pipe, no acetylene girth welds.	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Seam type	Seamless	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Joint factor	1.0 (195.106)	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	Operating pressure history	Never operated above 700# or 24.5% of SMYS	Pressure testing and pipe replacement	
4	Construction, Manufacturing, and Materials	MOP	1440		
4	Construction, Manufacturing, and Materials	% SMYS at MOP	50.50%		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Results from previous testing/inspection. [see 195.452(h)]	None found	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Leak and repair history.	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not needed, installed 1980	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy Crude Oil	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Pipe wall thickness (thicker walls give a better safety margin).	0.438	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Local environmental factors that could affect the pipeline (corrosivity of soil, subsidence, climatic)	subsidence	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	***ROW surveys cunducted more Freq.***
4	Construction, Manufacturing, and Materials	Time since the last internal inspection/pressure testing.	22 months	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Previously discovered defects/anomalies, including type, growth rate, and size.	None to date	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing, and Materials	Operating stress levels in the pipeline. Exposure of pipeline to exceed MOP	PSH's set at 700#, PRV is set at 1400#	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	***PSH set at 700# at the request of Crimson PL***
4	Construction, Manufacturing, and Materials	Physical support of the pipeline segment such as by a cable suspension bridge. Includes external loading and stress.	NA	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	None	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Elevation profile	Level	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Install new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Reduce operating stress level (% SMYS)	Not Needed	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Review and improve welding procedures	Approved welding procedures already in place.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct NDT inspection on welds	Original welds x-rayed and inspected	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	
4	Construction, Manufacturing, and Materials	Conduct exposed pipe inspections reports and bellholes.	Inspections performed twice annually.	Pressure testing and pipe replacement or, excavation protocols per ASME appendix A, section A5.5.	

	Beta Delivery line # 3	Segment #7, Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
4	Construction, Manufacturing,and Materials Threat Summary		Yes considered a threat due to age of line.		

Beta Delivery line # 3 | Segment #7. Beta Shipping Line # 3

Beta (CSFM # 1201) — = unknown data, or unsat data

Updated: Feb 18, 2009 — = no threat

= threat

FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet. Rev #2009-1

Threat #	INTEGRITY THREATS -IMP ELEMENT #2	Minimum Data Sets to be Collected & Reviewed for Each HCA Segment	Segment specific data and summary comments:	Integrity Assessment Methods for this Threat	COMMENTS and RECOMMENDATIONS
5	Third Party Damage Threat	Results from previous testing/inspection. [see 195.452(h)]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Leak and repair history.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	Coal Tar Enamel with 15 LBS Felt. Shows no signs of disbondment	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipe wall thickness (thicker walls give a better safety margin).	0.438	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Time since the last internal inspection/pressure testing.	22 months	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Previously discovered defects/anomalies, including type, growth rate, and size.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 700#, PRV is set at 1400#	ILI, pressure tests, exposed pipe reports	***PSH set at 700# at the request of Crimson PL***
5	Third Party Damage Threat	Construction activity in the area.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [H.02.a]	Only using DOT Qualified company personnel for DOT task.	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Participating in one-call systems and monitoring "One Call" activity more closely. [H.02.a]	Yes, USA	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If evidence of encroahment without monitoring, excavations or above gnd electrical survey per NACE RP-0502. [H.02.a]	Yes	ILI, pressure tests, exposed pipe reports	

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
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	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
5	Third Party Damage Threat	Improve line marking	Always open to improvements, none needed at this time	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Install optical electronic detection and/or sound detection system.	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Increase depth of cover	None needed at this time	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Line relocation	none	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve public education	Meeting requirement See O&M procedure 3.03	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Improve Right-of-Way (ROW) Maintenance	Weekly ROW inspections	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	More frequent ROW inspections	When activity rises in area	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Mechanical pipe inspection	None	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Additional pipe wall thickness	Not needed	ILI, pressure tests, exposed pipe reports	
5	Third Party Damage Threat	Pipeline marker tape over pipeline	None	ILI, pressure tests, exposed pipe reports	
5	**Third Party Damage Threat Summary**		Yes this segment is considered a threat due to fact that third party damage is major cause of pipeline accidents nationwide.	ILI, pressure tests, exposed pipe reports	

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
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			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
6	Incorrect Operations or Procedure Error Threat	Conduct self audits	Integrity program reviewed once per year. Audited by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Review and improve O&M procedures	Meets yearly requiremnts and been audited by agencies numerous times. Audited in by DOT in 2008	Audits by agency, company or 3rd party	
6	Incorrect Operations Threat	Conduct training, or improve existing training	OQ trng in place.	Audits by agency, company or 3rd party	
6	**Incorrect Operations Threat Summary**		**Yes this segment is considered a threat due to fact that incorrect operations is a cause of pipeline accidents nationwide.**	Audits by agency, company or 3rd party	
7	Equipment Threat	Leak and repair history.	NA	Repair of replace equip	
7	Equipment Threat	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 700#, PRV is set at 1400#	Repair of replace equip	***PSH set at 700# at the request of Crimson PL***
7	Equipment Threat	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	All standardized equipment used	Repair of replace equip	
7	Equipment Threat	Increase frequency of visual and mechanical inspections	NA	Repair of replace equip	
7	Equipment Threat	Improve or change design or materials	Always open to improvements, none needed	Repair of replace equip	
7	Equipment Threat	Review and improve O&M procedures	None needed at this time		
7	**Equipment Threat Summary**		**Yes this segment is considered a threat due to fact equipment failures can be a a cause of pipeline accidents.**		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Joint method (mechancial coupling, acetylene weld, arc weld)	All arc welded	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Topicgraphical and soil conditions (unstable slops, water crossings, water proximity, soil liquefactions susceptibility)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Earthquake fault	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Profile of ground of ground acceleration near fault zones (>0.2 g acceleration)	Liquidfication zone see link in attached comment	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Depth of frost line	NA	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Year of installation	1980	O&M inspections	
8	Natural Forces Damage (earthquake, hurricane, flood, freezing,etc.)	Pipe grade, diameter, wall thickness (internal stress calcs added to external loading, total stress not to excedd 100% SMYS)	Mild Steel API 5L GR B. 0.438 WT	O&M inspections	

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			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
8	**Natural Forces Damage threat summary**		Yes this segment is considered a threat due to being in a fault zone.	O&M inspections	
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Located in environmentally sensitive area.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	PSH's set at 700#, PRV is set at 1440#		***PSH set at 700# at the request of Crimson PL***
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	None		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	Line equiped with remote controlled MOV		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Relocate line	None		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install H2S sensors and/or fuel gas sensors	Not a high H2S facility		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Install or improve computerized monitoring	Already in place		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
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			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet. Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
9	Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
9	**Health & Safety Impact - Detecting & Minimizing Consequences of Unintended Releases Threat Summary**		**Yes this segment is considered a threat .**		
10	Environmental Impact	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
10	Environmental Impact	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
10	Environmental Impact	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		
10	Environmental Impact	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
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	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
10	Environmental Impact	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	Pipeline is in streets making monitoring very easy		
10	Environmental Impact	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
10	Environmental Impact	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	Line equiped with remote controlled MOV		
10	Environmental Impact	Relocate line	None		
10	Environmental Impact	Install H2S sensors and/or fuel gas sensors	NA		
10	Environmental Impact	Install or improve computerized monitoring	Already in place		
10	Environmental Impact	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
10	Environmental Impact	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
10	Environmental Impact	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
10	Environmental Impact	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
10	Environmental Impact	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
10	**Environmental Impact Threat Summary**		Yes this segment is considered a threat .		
11	Property Damage	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	Line is within HCA		
11	Property Damage	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	Heavy crude Oil		
11	Property Damage	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	10 Bbls as per ICP Annex H		
11	Property Damage	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	50.5% of SMYS at MOP of 1440#		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
11	Property Damage	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	Pipeline is in streets making monitoring very easy		
11	Property Damage	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
11	Property Damage	Install automatic shut-off and/or remote control valves. See protocol H.07.a for factors.	Line equiped with remote controlled MOV		
11	Property Damage	Relocate line	None		
11	Property Damage	Install H2S sensors and/or fuel gas sensors	NA		
11	Property Damage	Install or improve computerized monitoring	Already in place		
11	Property Damage	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
11	Property Damage	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
11	Property Damage	Additional training on emergency procedures to reduce emergency response time with	Annual training conducted		
11	Property Damage	Conduct drill with emergency officials	Annual drills with agencies for ICP.		
11	Property Damage	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
11	**Property Damage Threat Summary**		Yes this segment is considered a threat .		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct self audits	Integrity program (IMP), OQ and O&M reviewed once per year.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Review and improve O&M procedures	Meets yearly requiremnts and has been audited by DOT & CSFM in 2008.		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Conduct training, or improve existing training	OQ training in place		
12	Alternate Modes of Operation (e.g., startup, shutdown, shut-in, slack line, pressure cycling, etc.)	Reduce operating stress level (% SMYS)	Not needed but would operate at 50.5% of SMYS at MOP of 1440#		

	Beta Delivery line # 3	Segment #7. Beta Shipping Line # 3			
	Beta (CSFM # 1201)		= unknown data, or unsat data		
	Updated: Feb 18, 2009		= no threat		
			= threat		
	FN: SPBPL Liquid IMP Threat Analysis & Data Worksheet, Rev #2009-1				
Threat #	**INTEGRITY THREATS -IMP ELEMENT #2**	**Minimum Data Sets to be Collected & Reviewed for Each HCA Segment**	**Segment specific data and summary comments:**	**Integrity Assessment Methods for this Threat**	**COMMENTS and RECOMMENDATIONS**
12	Alternate Modes of Operation Threat Summary		Yes this segment is considered a threat .		
13	Interactive Threat	Manufacturing defect activated by pressure cycling	Yes this segment is considered a threat .		
14	Interactive Threat	Corrosion accelerated by TPD	Yes this segment is considered a threat .		
15	Interactive Threat	Corrosion accelerated by outside force	Yes this segment is considered a threat .		
16	Other segment specific threats summary		None		

	Risk Analysis Factor Cross Reference													
	Updated: Sept 12, 2008													
		Threats												
		[illegible]al Corrosion	Internal Corrosion	Stress Corrosion Cracking	Const., Manf., and Materials	Third Party Damage	Incorrect Operations or Procedure Error	Equipment Failures	Natural Forces Damage	Health and Safety Impact	Environmental Impact	Property Damage	Alternate Modes of Operation	Summary and Additional Comments
Factor #	**Minimum Required Factors to be used in Risk Analysis**													
1	Populated areas, unusually sensitive environmental areas, National Fish Hatcheries, commercially navigable waters, areas where people congregate.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
2	Results from previous testing/inspection. [see 195.452(h), integrity testing]	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
3	Leak and repair history.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
4	Cathodic protection history and known corrosion or condition of pipeline. [see 195.452(g)]	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
5	Type, quality, and condition of pipe coating (disbonded coating results in corrosion).	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
6	Age of pipe. Consider installing new pipe to improve manufacturing process, seam type, joint factor, and pipe type.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
7	Characteristics of product transported (highly volatile, highly flammable and toxic liquids present a greater threat).	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
8	Pipe wall thickness (thicker walls give a better safety margin).	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
9	Amount of product that could be released (i.e., size of pipe, higher volume release if the pipe ruptures).	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
10	Local environmental factors that could affect the pipeline (corrosivity of soil, subsidence, climatic)	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
11	Security of throughput (effects on customers if there is failure requiring shutdown).	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
12	Time since the last internal inspection/pressure testing.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
13	Previously discovered defects/anomalies, including type, growth rate, and size.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
14	Pipeline design criteria and operating stress levels in the pipeline. Exposure of pipeline to exceed MOP.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	

Risk Analysis Factor Cross Reference
Updated: Sept 12, 2008

Threats

		External Corrosion	Internal Corrosion	Stress Corrosion Cracking	Const., Manf., and Materials	Third Party Damage	Incorrect Operations or Procedure Error	Equipment Failures	Natural Forces Damage	Health and Safety Impact	Environmental Impact	Property Damage	Alternate Modes of Operation	Summary and Additional Comments
15	Location of the pipeline segment as it relates to the ability of the operator to detect and respond to a leak. (e.g., pipelines deep underground, or in locations that make leak detection difficult without specific sectional monitoring and/or significantly	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
16	Physical support of the pipeline segment such as by a cable suspension bridge. Includes external loading and stress.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
17	Non-standard or other than recognized industry practice on pipeline installation (e.g., horizontal directional drilling).	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
18	Terrain surrounding the pipeline including elevation profile, farm drain tiles, conduits.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
19	Construction activity in the area.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
20	General health and safety factors (employees and public)	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
21	Environmental impacts	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
22	Property damage	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
23	Local economic impact	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
24	Elevation profile	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
25	Possibility of spillage into farm field following the drain till into a waterway	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
26	Ditches along side a roadway the pipeline crosses	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
27	Using qualified personnel for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [H.02.a]	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
28	Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments and the root cause analysis to support ID of targeted additional P&M in HCA areas. [H.02.a]	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
29	Participating in one-call systems and monitoring "One Call" activity more closely. [H.02.a]	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	

3

Risk Analysis Factor Cross Reference

Updated: Sept 12, 2008

		Threats												
		[illegible]al Corrosion	Internal Corrosion	Stress Corrosion Cracking	Const., Manf., and Materials	Third Party Damage	Incorrect Operations or Procedure Error	Equipment Failure	Natural Forces Damage	Health and Safety Impact	Environmental Impact	Property Damage	Alternate Modes of Operation	Summary and Additional Comments
30	Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If evidence of encroahment without monitoring, excavations or above gnd electrical survey per NACE RP-0502. [H.02.a]	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
31	Improve line marking	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
32	Install optical electronic detection and/or sound detection system.	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
33	Increase depth of cover	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
34	Install more CP test stations	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
35	Improve public education	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
36	Improve Right-of-Way (ROW) Maintenance	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
37	More frequent ROW inspections	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
38	Mechanical pipe Inspection	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
39	Line relocation	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
40	Pipeline marker tape over pipeline	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
41	Close interval survey	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
42	Open hole inspections	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
43	Corrosion monitoring - probe	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	
44	Fluid analysis for corrosive properties	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	

BETA Liquid IMP RISK RANK AND SCHEDULE

Updated: Feb 19, 2009
PHMSA Operator ID: #
CSFM Line ID#: 2000A

Priority #	Beta Segment # 1-7	HCA Segment Name	Avg Risk Rank Score	Date of Last Assessment	Assess Interval (yrs)	Scheduled Date of Next Assessment	Assess Method (ILI, Pressure Test, Other) and type of ILI Tools Used (smart pigs)	Basis for Assesment Method (Threats Identified)	MILES	Nominal Outside Diameter	Method HCA Identified	Comments and Validation:
1	1	SPBPL Riser	8.09	9/1/07	2	8/31/09	ILI - Smart pig (MFL) and UT lamination once every 4 years	External and internal corrosion, Manf. Defects (Laminations)	0.16	16.000	NPMS & Local experts	The two year re-assessment interval is adequate based on review of operating history and the operating pressure.
2	2	SPBPL Sub Sea	7.56	9/1/07	2	8/31/09	ILI - Smart pig (MFL) and UT lamination once every 4 years	External and internal corrosion, TPD, Manf. Defects (Laminations)	15.35	16.000	NPMS & Local experts	The two year re-assessment interval is adequate based on review of operating history and the operating pressure.
3	3	SPBPL Onshore	8.09	9/1/07	2	8/31/09	ILI - Smart pig (MFL) and UT lamination once every 4 years	External and internal corrosion, TPD, Manf. Defects (Laminations)	2.03	16.000	NPMS & Local experts	The two year re-assessment interval is adequate based on review of operating history and the operating pressure.
4	4	Beta Station	8.18	Sep-80	20	Aug-00	API 653 tank Inspection	External and internal corrosion	0.00	Tank	NPMS & Local experts	PHMSA approved 2 year special permit for API 653 integrity inspection of tank. Due Feb 20101
5	5	Beta Shipping Line # 1 (Line Out of service since 1995)	8.27	Sep-80	NA	Before start up of pipeline	Pressure Test (line not piggable)	External and internal corrosion, TPD, natural forces.	0.26	10.000	NPMS & Local experts	The five year re-assessment interval is adequate based on review of operating history and the operating pressure. Line is currently OOS
6	6	Beta Shipping Line # 2	8.18	6/1/07	5	5/30/12	Pressure Test (line not piggable)	External and internal corrosion, TPD, natural forces.	0.26	10.000	NPMS & Local experts	The five year re-assessment interval is adequate based on review of operating history and the operating pressure.
7	7	Beta Shipping Line # 3	8.18	6/1/07	5	5/30/12	ILI - Smart pig (MFL)	External and internal corrosion, TPD, natural forces.	0.26	10.000	NPMS & Local experts	The five year re-assessment interval is adequate based on review of operating history and the operating pressure.
									18.32			

MOP Calculation
Per Pipeline Segment

BETA HAZARDOUS LIQUID PIPELINE MOP SUMMARY

Pipeline Segment	Segment MOP (psi)	Governing Component	Pipeline MOP (psi)	Operating Pressure (psi)	PSV Protection (psi)	Wall Thick. (Inch)	Pressure Test (psi)	Pressure Test Year	Installation Year	Segment Class
SPBPL - Seg 1a	1152	Pressure Test	1152	240-400	1100	0.844	1440	2000	1980	
SPBPL - Seg 1b	1152	Pressure Test	1152	240-400	1100	0.844	1440	2000	1980	
SPBPL - Seg 2	1152	Pressure Test	1152	240-400	1100	0.500	1440	2000	1980	
SPBPL - Seg 3a1	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	1980	
SPBPL - Seg 3ar1	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	2000	
SPBPL - Seg 3a2	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	1980	
SPBPL - Seg 3b1	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	1980	
SPBPL - Seg 3br1	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	1991	
SPBPL - Seg 3b2	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	1979	
SPBPL - Seg 3br2	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	1993	
SPBPL - Seg 3br3	1152	Pressure Test	1152	240-400	1100	0.500	1440	2000	1993	
SPBPL - Seg 3br4	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	1993	
SPBPL - Seg 3b3	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	1980	
SPBPL - Seg 3c	1152	Pressure Test	1152	240-400	1100	0.375	1440	2000	1980	
Delivery Line #3	1440	Component	1440	400	1370	0.438	2160	1980	1980	
Delivery Line #2	1440	Component	1440	690	1370	0.438	2160	1980	1980	
Out Of Service - Pipelines de-oiled and filled with inhibited water										
Delivery Line #1	320	Pressure Test	400	400	1400	0.438	500	2001	1980	

Last Update: 3/12/2007

San Pedro Bay Pipeline Co.
Beta Production Unit

16" Elly to Long Beach Crude Oil Pipeline
(16" flange downstream of Elly Main Line Block Valve to 16" flange upstream of Beta Station Main Line Block Valve)

Description	Length	Length	OD of Pipe	Wall Thickness	Pipe	Pipe	Pipe ID	Volume	Volume / foot	Volume
	feet	miles	inches	inches	Grade	Spec	in	gal.	bbls/ft	bbls
Flange DS of MLBV to Two Bends	124	0.023	16	0.844	API 5L Gr B	ANSI	14.312	1,035		25
Two Bends just above +13.67 Elev Flange	41	0.008	16	0.844	API 5L Gr B	ANSI	14.312	344		8
+13.67 Elev to -42 Elev	56	0.011	16	0.844	API 5L Gr B	ANSI	14.312	469		11
-42 Elev to -60.5 Elev + 2 45 deg 2' long radius bends	13	0.003	16	0.844	API 5L Gr B	ANSI	14.312	111		3
-60.5 Elev to -236 Elev 7 deg comb batter	177	0.033	16	0.844	API 5L Gr B	ANSI	14.312	1,478		35
Swivel Flng to Station 0+00	39	0.007	16	0.844	5LX42	API	14.312	323		8
Station 0+00 to Station 3+74	374	0.071	16	0.844	5LX42	API	14.312	3,125		74
Total Top Side/Riser/Approach Pipe	824	0.156	16	0.844	API 5LX Gr B Riser & Gr X42 Appr.	ANSI & API	14.312	6,884	0.1990	164
Offshore in OCS Waters	33,459	6.337	16	0.5	5LX42	API	15.000	307,134		7,313
Total Offshore in OCS Waters	**34,283**	**6.493**	**16**	**0.844 / 0.6**	**API 5LX Gr B Riser, Gr. X42 Appr. & Gr X42 Offshore**	**ANSI & API**	**14.312 / 15.001**	**314,017**		**7,477**
Offshore in State Waters	23,347	4.422	16	0.5	5LX42	API	15.000	214,313	0.2186	5,103
Offshore in City of Long Beach Waters	21,987	4.164	16	0.5	5LX42	API	15.000	201,825		4,805
Offshore in Port of Long Beach Waters	1,412	0.267	16	0.5	5LX42	API	15.000	12,965		309
Total Offshore in State Waters	**46,747**	**8.854**	**16**	**0.5**	**5LX42**	**API**	**15.000**	**429,103**		**10,217**
Total Offshore Pipe	**81,030**	**15.347**	**16**	**0.844 / 0.5**	**API 5LX Gr B Riser, Gr X42 Appr. & Gr X42 Offshore**	**ANSI & API**	**14.312 / 15.000**	**743,120**		**17,693**
Onshore	7,483	1.417	16	0.375	5LX52	API	15.250	70,995	0.2259	1,690
Onshore Pipe Change	238	0.045	16	0.5	5LX52	API	15.000	2,182		52
Onshore to flange US of MLBV	2,960	0.561	16	0.375	5LX52	API	15.250	28,086		669
Total Onshore Pipe	**10,681**	**2.023**	**16**	**0.375 / 0.5**	**API 5IX Gr X52 / Gr B**	**API**	**15.250 / 15.000**	**101,263**		**2,411**
Total Offshore & Onshore Pipe	**91,710**	**17.369**	**16**	**0.844 / 0.5 / 0.375**	**API 5LX Gr B, Gr. X42 and Gr. X52**	**ANSI & API**	**14.312 / 15.000 / 15.250**	**844,383**		**20,104**

San Pedro Bay Pipeline Co.
Beta Production Unit
16" Elly to Long Beach Crude Oil Pipeline (Launcher Flange to Receiver Flange)

Description	Length	Length	OD of Pipe	Wall Thickness	Pipe	Pipe	Pipe ID	Volume	Volume / foot	Volume
	feet	miles	inches	inches	Grade	Spec	in	gal.	bbls/ft	bbls
Launcher Flange to Flange DS of MLBV	29	0.005	16	0.562	API 5L Gr B	ANSI	14.876	257		6
Flange DS of MLBV to Two Bends	124	0.023	16	0.844	API 5L Gr B	ANSI	14.312	1,035		25
Two Bends just above +13.67 Elev Flange	41	0.008	16	0.844	API 5L Gr B	ANSI	14.312	344		8
+13.67 Elev to -42 Elev	56	0.011	16	0.844	API 5L Gr B	ANSI	14.312	469		11
-42 Elev to -60.5 Elev + 2 45 deg 2' long radius bends	13	0.003	16	0.844	API 5L Gr B	ANSI	14.312	111		3
-60.5 Elev to -236 Elev 7 deg comb batter	177	0.033	16	0.844	API 5L Gr B	ANSI	14.312	1,478		35
Swivel Flng to Station 0+00	39	0.007	16	0.844	5LX42	API	14.312	323		8
Station 0+00 to Station 3+74	374	0.071	16	0.844	5LX42	API	14.312	3,125		74
Total Top Side/Riser/Approach Pipe	**852**	**0.161**	**16**	**0.562 / 0.844**	**API 5LX Gr B Riser & Gr X42 Appr.**	**ANSI & API**	**14.876 / 14.312**	**7,141**	**0.1995**	**170**
Offshore in OCS Waters	33,459	6.337	16	0.5	5LX42	API	15.000	307,134		7,313
Total Offshore in OCS Waters	**34,311**	**6.498**	**16**	**0.844 / 0.6**	**API 5LX Gr B Riser, Gr. X42 Appr. & Gr X42 Offshore**	**ANSI & API**	**14.312 / 15.001**	**314,275**		**7,483**
Offshore in State Waters	23,347	4.422	16	0.5	5LX42	API	15.000	214,313	0.2186	5,103
Offshore in City of Long Beach Waters	21,987	4.164	16	0.5	5LX42	API	15.000	201,825		4,805
Offshore in Port of Long Beach Waters	1,412	0.267	16	0.5	5LX42	API	15.000	12,965		309
Total Offshore in State Waters	**46,747**	**8.854**	**16**	**0.5**	**5LX42**	**API**	**15.000**	**429,103**		**10,217**
Total Offshore Pipe	**81,058**	**15.352**	**16**	**0.844 / 0.5**	**API 5LX Gr B Riser, Gr X42 Appr. & Gr X42 Offshore**	**ANSI & API**	**14.312 / 15.000**	**743,378**		**17,699**
Onshore	7,483	1.417	16	0.375	5LX52	API	15.250	70,995	0.2259	1,690
Onshore Pipe Change	238	0.045	16	0.5	5LX52	API	15.000	2,182		52
Onshore to flange US of MLBV	2,960	0.561	16	0.375	5LX52	API	15.250	28,086		669
Flange US of MLBV to Receiver Flange	16	0.003	16	0.562	5L Gr B	API	14.876	144		3
Total Onshore Pipe	**10,697**	**2.026**	**16**	**0.375 / 0.5**	**API 5IX Gr X52 / Gr B**	**API**	**15.250 / 15.000**	**101,407**		**2,414**
Total Offshore & Onshore Pipe	**91,755**	**17.378**	**16**	**0.844 / 0.5 / 0.375**	**API 5LX Gr B, Gr. X42 and Gr. X52**	**ANSI & API**	**14.312 / 15.000 / 15.250**	**844,784**		**20,114**

Pacific Energy Res. Ltd

SHEET NO.	1 OF
JOB NO.	
DATE	25-Aug-06
DESIGN	Poe/Miller
CHECK	REA/AB

Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**

Pipeline Segment	=	**Platform Elly: Pipeline inlet to riser, elevation subsea minus 236 ft.**		
Pipeline Description	=	**San Pedro Bay Pipeline (SPBPL) Riser**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 185 Deg F**
Operating Pressure, P	=	**500**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.844**	in.	
Specified Minimum Yield Strgth.	=	**35000**	psig	**Grade B**
Design Factor	=	**0.60**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5L GR B Seamless, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**Seamless**
Manufacture Date	=	**1979**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where:
- P= Design Pressure, psi, (Sec. 195.106(a))
- S= Yield Strength, psi (Sec. 195.106(b))
- t= Wall Thickness, in. (Sec. 195.106(c))
- F= Design Factor, (Sec. 195.106(a))
- E= Seam Joint Factor, (Sec. 195.106(e))
- T= Temperature Derating Factor, (Sec. 195.102)
- D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 35000 \times 0.844 \times 0.60 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 35000 \times 0.844 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = **2216** psi

$P_{100\%\ SMYS}$ = 3693 psi		$P_{72\%\ SMYS}$ = 2659 psi		$P_{40\%\ SMYS}$ = 1477 psi	
$P_{80\%\ SMYS}$ = 2954 psi		$P_{60\%\ SMYS}$ = 2216 psi		$P_{30\%\ SMYS}$ = 1108 psi	
$P_{75\%\ SMYS}$ = 2769 psi		$P_{50\%\ SMYS}$ = 1846 psi		$P_{20\%\ SMYS}$ = 739 psi	

(2) Maximum Design Pressure of Components

900 Series Components	2160	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **2160** psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152** psi

(4) Segment MOP = **1152** psi

(5) OVERALL PIPELINE MOP = **1152** psi

(6) MOP % of SMYS 31.20%

Pacific Energy Res. Ltd

Sheet No.	1 of
Job No.	
Date	25-Aug-06
Design	Poe/Miller
Check	REA/AB

Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**

Pipeline Segment	=	**Platform Elly: Elevation subsea minus 236 ft. to Station 3+74**		
Pipeline Description	=	**San Pedro Bay Pipeline (SPBPL) Riser Approach pipe**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 185 Deg F**
Operating Pressure, P	=	**500**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.844**	in.	
Specified Minimum Yield Strgth.	=	**42000**	psig	**Grade X42**
Design Factor	=	**0.60**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X42, DSA, Cold Expanded Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**DSA**
Manufacture Date	=	**1979**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 42000 \times 0.844 \times 0.60 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 42000 \times 0.844 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = **2659** psi

$P_{100\%\ SMYS}$ = 4431 psi		$P_{72\%\ SMYS}$ = 3190 psi		$P_{40\%\ SMYS}$ = 1772 psi	
$P_{80\%\ SMYS}$ = 3545 psi		$P_{60\%\ SMYS}$ = 2659 psi		$P_{30\%\ SMYS}$ = 1329 psi	
$P_{75\%\ SMYS}$ = 3323 psi		$P_{50\%\ SMYS}$ = 2216 psi		$P_{20\%\ SMYS}$ = 886 psi	

(2) Maximum Design Pressure of Components

900 Series Components	2160	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **2160** psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152** psi

(4) Segment MOP = **1152** psi

(5) OVERALL PIPELINE MOP = **1152** psi

(6) MOP % of SMYS 26.00%

Pacific Energy Res. Ltd

SHEET NO.	1 OF
JOB NO.	
DATE	25-Aug-06
DESIGN	Poe/Miller
CHECK	REA/AB

Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**

Pipeline Segment	=	**Sub Sea Pipeline Station 3+74 to Station 802+83**		
Pipeline Description	=	**San Pedro Bay Pipeline - Offshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 185 Deg F**
Operating Pressure, P	=	**500**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.500**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X52, DSA, Cold Expanded, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**DSA**
Manufacture Date	=	**1979**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where:
P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.500 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.500 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = **2340** psi

$P_{100\%\ SMYS}$ = 3250 psi		$P_{72\%\ SMYS}$ = 2340 psi		$P_{40\%\ SMYS}$ = 1300 psi	
$P_{80\%\ SMYS}$ = 2600 psi		$P_{60\%\ SMYS}$ = 1950 psi		$P_{30\%\ SMYS}$ = 975 psi	
$P_{75\%\ SMYS}$ = 2438 psi		$P_{50\%\ SMYS}$ = 1625 psi		$P_{20\%\ SMYS}$ = 650 psi	

(2) Maximum Design Pressure of Components

900 Series Components	2160	psi
600 Series Components	1440	psi
		psi
		psi
		psi

$P_{Component}$ = **1440** psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152** psi

(4) Segment MOP = **1152** psi

(5) OVERALL PIPELINE MOP = **1152** psi

(6) MOP % of SMYS 35.45%

Pacific Energy Res. Ltd	SHEET NO. 1 OF
	JOB NO.
	DATE 25-Aug-06
	DESIGN Poe/Miller
Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**	CHECK REA/AB

Pipeline Segment	=	**Onshore Pipeline: Station 802+83 (Offshore) to Station 3+00.7 (Onshore)**		
Pipeline Description	=	**Onshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**
Operating Pressure, P	=	**150**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.375**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X52, DSA, Cold Expanded, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**DSA, cold expanded**
Manufacture Date	=	**1979**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = 1755 psi		
$P_{100\%\ SMYS}$ = 2438 psi	$P_{72\%\ SMYS}$ = 1755 psi	$P_{40\%\ SMYS}$ = 975 psi
$P_{80\%\ SMYS}$ = 1950 psi	$P_{60\%\ SMYS}$ = 1463 psi	$P_{30\%\ SMYS}$ = 731 psi
$P_{75\%\ SMYS}$ = 1828 psi	$P_{50\%\ SMYS}$ = 1219 psi	$P_{20\%\ SMYS}$ = 488 psi

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = 1440 psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = 1152 psi

(4) Segment MOP = 1152 psi

(5) OVERALL PIPELINE MOP = 1152 psi

(6) MOP % of SMYS 47.26%

Pacific Energy Res. Ltd

Sheet No.	1 of
Job No.	
Date	20-May-05
Design	Poe/Miller
Check	REA/AB

Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**

Pipeline Segment	=	Onshore Pipeline: Station 3+00.7 (Onshore) to Station 3+09.9 (Onshore)			
Pipeline Description	=	Onshore Pipeline			
Process Product	=	Crude Oil			
Design Temperature		< or = 250	Degrees F		Sec. 192.115
Design Temperature Factor	=	1.000			Highest product temp. 100 Deg F
Operating Pressure, P	=	150	psig		
Pipeline Outside Diameter	=	16	in.		
Pipeline Wall Thickness, original	=	0.375	in.		
Specified Minimum Yield Strgth.	=	52000	psig		Grade X52
Design Factor	=	0.72	Sec. 195.106(a)		
External Coating	=	Yes	in.		
Material	=	API 5LX Grade X52, ERW, non-expanded, Steel Line Pipe			
Joint Efficiency, E	=	1.00			ERW, non-expanded
Manufacture Date	=	2000			
Test Pressure	=	1440	psig	Date =	9/26/2000
					Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = **1755 psi**

$P_{100\%\ SMYS}$ = 2438 psi		$P_{72\%\ SMYS}$ = 1755 psi		$P_{40\%\ SMYS}$ = 975 psi	
$P_{80\%\ SMYS}$ = 1950 psi		$P_{60\%\ SMYS}$ = 1463 psi		$P_{30\%\ SMYS}$ = 731 psi	
$P_{75\%\ SMYS}$ = 1828 psi		$P_{50\%\ SMYS}$ = 1219 psi		$P_{20\%\ SMYS}$ = 488 psi	

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **1440 psi**

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152 psi**

(4) Segment MOP = **1152 psi**

(5) OVERALL PIPELINE MOP = **1152 psi**

(6) MOP % of SMYS 47.26%

Pacific Energy Res. Ltd	SHEET NO.	1 OF
	JOB NO.	
	DATE	25-Aug-06
	DESIGN	Poe/Miller
Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**	CHECK	REA/AB

Pipeline Segment	=	**Onshore Pipeline: Station 3+09.9 (Onshore) to Station 9+55.12 (Onshore)**		
Pipeline Description	=	**Onshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**
Operating Pressure, P	=	**150**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.375**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X52, DSA, Cold Expanded, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**DSA, cold expanded**
Manufacture Date	=	**1979**		
Test Pressure	=	**1440**	psig	**Date** = **9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = **1755** psi

$P_{100\%\ SMYS}$ =	2438 psi	$P_{72\%\ SMYS}$ =	1755 psi	$P_{40\%\ SMYS}$ =	975 psi
$P_{80\%\ SMYS}$ =	1950 psi	$P_{60\%\ SMYS}$ =	1463 psi	$P_{30\%\ SMYS}$ =	731 psi
$P_{75\%\ SMYS}$ =	1828 psi	$P_{50\%\ SMYS}$ =	1219 psi	$P_{20\%\ SMYS}$ =	488 psi

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **1440** psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152** psi

(4) Segment MOP = **1152** psi

(5) OVERALL PIPELINE MOP = **1152** psi

(6) MOP % of SMYS 47.26%

SHEET NO.	1 OF
JOB NO.	
DATE	25-Aug-06
DESIGN	Poe/Miller
CHECK	REA/AB

Pacific Energy Res. Ltd

Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**

Pipeline Segment	=	**Onshore Pipeline: Station 9+55.12 to Station 72+07.92**		
Pipeline Description	=	**Onshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**
Operating Pressure, P	=	**150**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.375**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X52, ERW, non-expanded, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**ERW, non-expanded**
Manufacture Date	=	**1979**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ =	1755	psi
$P_{100\%\ SMYS}$ =	2438	psi
$P_{80\%\ SMYS}$ =	1950	psi
$P_{75\%\ SMYS}$ =	1828	psi

$P_{72\%\ SMYS}$ =	1755	psi
$P_{60\%\ SMYS}$ =	1463	psi
$P_{50\%\ SMYS}$ =	1219	psi

$P_{40\%\ SMYS}$ =	975	psi
$P_{30\%\ SMYS}$ =	731	psi
$P_{20\%\ SMYS}$ =	488	psi

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = 1440 psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = 1152 psi

(4) Segment MOP = 1152 psi

(5) OVERALL PIPELINE MOP = 1152 psi

(6) MOP % of SMYS 47.26%

Pacific Energy Res. Ltd	SHEET NO. 1 OF
	JOB NO.
	DATE 25-Aug-06
	DESIGN Poe/Miller
Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**	CHECK REA/AB

Pipeline Segment	=	**Onshore Pipeline: Station 72+07.92 to Station 72+89.35 AH / 72+91.35 BK**		
Pipeline Description	=	**Onshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**
Operating Pressure, P	=	**150**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.375**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X52, ERW, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**ERW**
Manufacture Date	=	**1991**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = 1755 psi		
$P_{100\%\ SMYS}$ = 2438 psi	$P_{72\%\ SMYS}$ = 1755 psi	$P_{40\%\ SMYS}$ = 975 psi
$P_{80\%\ SMYS}$ = 1950 psi	$P_{60\%\ SMYS}$ = 1463 psi	$P_{30\%\ SMYS}$ = 731 psi
$P_{75\%\ SMYS}$ = 1828 psi	$P_{50\%\ SMYS}$ = 1219 psi	$P_{20\%\ SMYS}$ = 488 psi

(2) Maximum Design Pressure of Components

	psi
	psi
	psi
	psi
	psi

$P_{Component}$ = N/A psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = 1152 psi

(4) Segment MOP = 1152 psi

(5) OVERALL PIPELINE MOP = 1152 psi

(6) MOP % of SMYS 47.26%

Pacific Energy Res. Ltd

SHEET NO.	1 OF
JOB NO.	
DATE	20-May-05
DESIGN	Poe/Miller
CHECK	REA/AB

Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**

Pipeline Segment	=	**Onshore Pipeline: Station 72+89.35 AH / 72+91.35 BK to Station 73+07.4**		
Pipeline Description	=	**Onshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**
Operating Pressure, P	=	**150**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.375**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X52, ERW, non-expanded, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**ERW, non-expanded**
Manufacture Date	=	**1991**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where:
- P= Design Pressure, psi, (Sec. 195.106(a))
- S= Yield Strength, psi (Sec. 195.106(b))
- t= Wall Thickness, in. (Sec. 195.106(c))
- F= Design Factor, (Sec. 195.106(a))
- E= Seam Joint Factor, (Sec. 195.106(e))
- T= Temperature Derating Factor, (Sec. 195.102)
- D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = **1755 psi**

$P_{100\%\ SMYS}$ =	2438 psi		$P_{72\%\ SMYS}$ =	1755 psi		$P_{40\%\ SMYS}$ =	975 psi
$P_{80\%\ SMYS}$ =	1950 psi		$P_{60\%\ SMYS}$ =	1463 psi		$P_{30\%\ SMYS}$ =	731 psi
$P_{75\%\ SMYS}$ =	1828 psi		$P_{50\%\ SMYS}$ =	1219 psi		$P_{20\%\ SMYS}$ =	488 psi

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **1440 psi**

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152** psi

(4) Segment MOP = **1152** psi

(5) OVERALL PIPELINE MOP = **1152** psi

(6) MOP % of SMYS 47.26%

Pacific Energy Res. Ltd

Sheet No.	1 of
Job No.	
Date	25-Aug-06
Design	Poe/Miller
Check	REA/AB

Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**

Pipeline Segment	=	**Onshore Pipeline: Station 73+07.4 to Station 73+73.5**		
Pipeline Description	=	**Onshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**
Operating Pressure, P	=	**150**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.375**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X52, ERW, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**ERW**
Manufacture Date	=	**1993**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$	=	**1755**	psi
$P_{100\%\ SMYS}$	=	2438	psi
$P_{80\%\ SMYS}$	=	1950	psi
$P_{75\%\ SMYS}$	=	1828	psi

$P_{72\%\ SMYS}$	=	1755	psi
$P_{60\%\ SMYS}$	=	1463	psi
$P_{50\%\ SMYS}$	=	1219	psi

$P_{40\%\ SMYS}$	=	975	psi
$P_{30\%\ SMYS}$	=	731	psi
$P_{20\%\ SMYS}$	=	488	psi

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **1440** psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152** psi

(4) Segment MOP = **1152** psi

(5) OVERALL PIPELINE MOP = **1152** psi

(6) MOP % of SMYS 47.26%

# Pacific Energy Res. Ltd	SHEET NO. 1 OF
	JOB NO.
	DATE 25-Aug-06
	DESIGN Poe/Miller
Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**	CHECK REA/AB

Pipeline Segment	=	**Onshore Pipeline: Station 73+73.5 to Station 76+11.2**		
Pipeline Description	=	**Onshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**
Operating Pressure, P	=	**150**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.500**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	**in.**	
Material	=	**API 5LX Grade X52, ERW, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**ERW**
Manufacture Date	=	**1993**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.500 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.500 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ =	**2340**	psi						
$P_{100\%\ SMYS}$ =	3250	psi	$P_{72\%\ SMYS}$ =	2340	psi	$P_{40\%\ SMYS}$ =	1300	psi
$P_{80\%\ SMYS}$ =	2600	psi	$P_{60\%\ SMYS}$ =	1950	psi	$P_{30\%\ SMYS}$ =	975	psi
$P_{75\%\ SMYS}$ =	2438	psi	$P_{50\%\ SMYS}$ =	1625	psi	$P_{20\%\ SMYS}$ =	650	psi

(2) Maximum Design Pressure of Components

	psi
	psi
	psi
	psi
	psi

$P_{Component}$ = N/A psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152** psi

(4) Segment MOP = **1152** psi

(5) OVERALL PIPELINE MOP = **1152** psi

(6) MOP % of SMYS 35.45%

Pacific Energy Res. Ltd

SHEET NO.	1 OF
JOB NO.	
DATE	20-May-05
DESIGN	Poe/Miller
CHECK	REA/AB

Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**

Pipeline Segment	=	**Onshore Pipeline: Station 76+11.2 to Station 91+24.1 BK / 89+66.7 AH**		
Pipeline Description	=	**Onshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**
Operating Pressure, P	=	**150**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.375**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X52, ERW, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**ERW**
Manufacture Date	=	**1993**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= *Design Factor, (Sec. 195.106(a))*
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = **1755** psi

$P_{100\%\ SMYS}$ = 2438 psi	$P_{72\%\ SMYS}$ = 1755 psi	$P_{40\%\ SMYS}$ = 975 psi
$P_{80\%\ SMYS}$ = 1950 psi	$P_{60\%\ SMYS}$ = 1463 psi	$P_{30\%\ SMYS}$ = 731 psi
$P_{75\%\ SMYS}$ = 1828 psi	$P_{50\%\ SMYS}$ = 1219 psi	$P_{20\%\ SMYS}$ = 488 psi

(2) Maximum Design Pressure of Components

	psi
	psi
	psi
	psi
	psi

$P_{Component}$ = **N/A** psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152** psi

(4) Segment MOP = **1152** psi

(5) OVERALL PIPELINE MOP = **1152** psi

(6) MOP % of SMYS 47.26%

Pacific Energy Res. Ltd	SHEET NO. 1 OF ___
	JOB NO.
	DATE 25-Aug-06
	DESIGN Poe/Miller
Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**	CHECK REA/AB

Pipeline Segment	=	**Onshore Pipeline: Station 91+24.1 BK / 89+66.7 AH to Station 103+35.6**			
Pipeline Description	=	***Onshore Pipeline***			
Process Product	=	**Crude Oil**			
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**	
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**	
Operating Pressure, P	=	**150**	psig		
Pipeline Outside Diameter	=	**16**	in.		
Pipeline Wall Thickness, original	=	**0.375**	in.		
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**	
Design Factor	=	**0.72**	Sec. 195.106(a)		
External Coating	=	**Yes**	in.		
Material	=	**API 5LX Grade X52, ERW, non-expanded, Steel Line Pipe**			
Joint Efficiency, E	=	**1.00**		**ERW, non-expanded**	
Manufacture Date	=	**1979**			
Test Pressure	=	**1440**	psig	**Date** =	**9/26/2000**
					Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ =	1755 psi						
$P_{100\%\ SMYS}$ =	2438 psi		$P_{72\%\ SMYS}$ =	1755 psi		$P_{40\%\ SMYS}$ =	975 psi
$P_{80\%\ SMYS}$ =	1950 psi		$P_{60\%\ SMYS}$ =	1463 psi		$P_{30\%\ SMYS}$ =	731 psi
$P_{75\%\ SMYS}$ =	1828 psi		$P_{50\%\ SMYS}$ =	1219 psi		$P_{20\%\ SMYS}$ =	488 psi

(2) Maximum Design Pressure of Components

	psi
	psi
	psi
	psi
	psi
$P_{Component}$ =	1440 psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = 1152 psi

(4) Segment MOP = 1152 psi

(5) OVERALL PIPELINE MOP = 1152 psi

(6) MOP % of SMYS 47.26%

Pacific Energy Res. Ltd	Sheet No. 1 of
	Job No.
	Date 25-Aug-06
	Design Poe/Miller
Subject: **San Pedro Bay Pipeline MOP Calculation - IMP Baseline Assessment**	Check REA/AB

Pipeline Segment	=	**Onshore Pipeline: Station 103+35.6 to Station 104+14.10**		
Pipeline Description	=	**Onshore Pipeline**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 100 Deg F**
Operating Pressure, P	=	**150**	psig	
Pipeline Outside Diameter	=	**16**	in.	
Pipeline Wall Thickness, original	=	**0.375**	in.	
Specified Minimum Yield Strgth.	=	**52000**	psig	**Grade X52**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**API 5LX Grade X52, DSA, Cold Expanded, Steel Line Pipe**		
Joint Efficiency, E	=	**1.00**		**DSA, cold expanded**
Manufacture Date	=	**1979**		
Test Pressure	=	**1440**	psig	**Date = 9/26/2000**
				Hydrotest 8-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 52000 \times 0.375 \times 0.72 \times 1.00 \times 1.000}{16.000}$$

$$P_{100\%\ SMYS} = \frac{2 \times 52000 \times 0.375 \times 1 \times 1.00 \times 1.000}{16.000}$$

$P_{Pipe\ Design}$ = **1755** psi

$P_{100\%\ SMYS}$ =	2438 psi	$P_{72\%\ SMYS}$ =	1755 psi	$P_{40\%\ SMYS}$ =	975 psi
$P_{80\%\ SMYS}$ =	1950 psi	$P_{60\%\ SMYS}$ =	1463 psi	$P_{30\%\ SMYS}$ =	731 psi
$P_{75\%\ SMYS}$ =	1828 psi	$P_{50\%\ SMYS}$ =	1219 psi	$P_{20\%\ SMYS}$ =	488 psi

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **1440** psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1152** psi

(4) Segment MOP = **1152** psi

(5) OVERALL PIPELINE MOP = **1152** psi

(6) MOP % of SMYS 47.26%

Pacific Energy Res. Ltd

Sheet No.	1 of
Job No.	
Date	12-Mar-07
Design	Poe/Miller
Check	REA/AB

Subject: **Beta Station to THUMS Manifold Delivery Line #1 - Commission of New Pipeline**

Pipeline Segment	=	**Beta Station Line #1 to THUMS Manifold**		
Pipeline Description	=	**Delivery Line #1**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 80 Deg F**
Operating Pressure, P	=	**320**	psig	
Pipeline Outside Diameter	=	**10.75**	in.	
Pipeline Wall Thickness, original	=	**0.438**	in.	
Specified Minimum Yield Strgth.	=	**35000**	psig	**Grade B**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**Mild Steel API 5L GR B**		
Joint Efficiency, E	=	**1.00**		**ERW, Non expanded**
Manufacture Date	=	**1979**		
Test Pressure	=	**2160**	psig	**Date = 9/9/1980**
				Hydrotest 24-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 35000 \times 0.438 \times 0.72 \times 1.00 \times 1.000}{10.750}$$

$$P_{100\%\ SMYS} = \frac{2 \times 35000 \times 0.438 \times 1 \times 1.00 \times 1.000}{10.750}$$

$P_{Pipe\ Design}$ = **2054** psi

$P_{100\%\ SMYS}$ = 2852 psi		$P_{72\%\ SMYS}$ = 2054 psi		$P_{40\%\ SMYS}$ = 1141 psi	
$P_{80\%\ SMYS}$ = 2282 psi		$P_{60\%\ SMYS}$ = 1711 psi		$P_{30\%\ SMYS}$ = 856 psi	
$P_{75\%\ SMYS}$ = 2139 psi		$P_{50\%\ SMYS}$ = 1426 psi		$P_{20\%\ SMYS}$ = 570 psi	

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **1440** psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1728** psi

(4) Segment MOP = **1440** psi

(5) OVERALL PIPELINE MOP = **1440** psi

(6) MOP % of SMYS 50.49%

Pacific Energy Res. Ltd

SHEET NO.	1 OF
JOB NO.	
DATE	12-Mar-07
DESIGN	Poe/Miller
CHECK	REA/AB

Subject: **Beta Station to THUMS Manifold Delivery Line #2 - Commission of New Pipeline**

Pipeline Segment	=	**Beta Station Line #2 to THUMS Manifold**		
Pipeline Description	=	**Delivery Line #2**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 80 Deg F**
Operating Pressure, P	=	**320**	psig	
Pipeline Outside Diameter	=	**10.75**	in.	
Pipeline Wall Thickness, original	=	**0.438**	in.	
Specified Minimum Yield Strgth.	=	**35000**	psig	**Grade B**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**Mild Steel API 5L GR B**		
Joint Efficiency, E	=	**1.00**		**ERW, Non expanded**
Manufacture Date	=	**1979**		
Test Pressure	=	**1830**	psig	**Date = 4/5/2007**
				Hydrotest 24-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 35000 \times 0.438 \times 0.72 \times 1.00 \times 1.000}{10.750}$$

$$P_{100\%\ SMYS} = \frac{2 \times 35000 \times 0.438 \times 1 \times 1.00 \times 1.000}{10.750}$$

$P_{Pipe\ Design}$ = **2054** psi

$P_{100\%\ SMYS}$ = 2852 psi	$P_{72\%\ SMYS}$ = 2054 psi	$P_{40\%\ SMYS}$ = 1141 psi
$P_{80\%\ SMYS}$ = 2282 psi	$P_{60\%\ SMYS}$ = 1711 psi	$P_{30\%\ SMYS}$ = 856 psi
$P_{75\%\ SMYS}$ = 2139 psi	$P_{50\%\ SMYS}$ = 1426 psi	$P_{20\%\ SMYS}$ = 570 psi

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **1440** psi

(3) Pressure Test

$P_{80\%\ of\ PT}$ = **1464** psi

(4) Segment MOP = **1440** psi

(5) OVERALL PIPELINE MOP = **1440** psi

(6) MOP % of SMYS 50.49%

Pacific Energy Res. Ltd

Sheet No.	1 of
Job No.	
Date	12-Mar-07
Design	Poe/Miller
Check	REA/AB

Subject: **Beta Station to THUMS Manifold Delivery Line #3 - Commission of New Pipeline**

Pipeline Segment	=	**Beta Station Line #3 to THUMS Manifold**		
Pipeline Description	=	**Delivery Line #3**		
Process Product	=	**Crude Oil**		
Design Temperature		**< or = 250**	Degrees F	**Sec. 192.115**
Design Temperature Factor	=	**1.000**		**Highest product temp. 80 Deg F**
Operating Pressure, P	=	**320**	psig	
Pipeline Outside Diameter	=	**10.75**	in.	
Pipeline Wall Thickness, original	=	**0.438**	in.	
Specified Minimum Yield Strgth.	=	**35000**	psig	**Grade B**
Design Factor	=	**0.72**	Sec. 195.106(a)	
External Coating	=	**Yes**	in.	
Material	=	**Mild Steel API 5L GR B**		
Joint Efficiency, E	=	**1.00**		**ERW, Non expanded**
Manufacture Date	=	**1979**		
Test Pressure	=	**2160**	psig	**Date = 9/9/1980**
				Hydrotest 24-hours

Maximum Operating Pressure (MOP) *Ref. Sec. 195.106*

$$P = \frac{2 \times St \times F \times E \times T}{D}$$

Where: P= Design Pressure, psi, (Sec. 195.106(a))
S= Yield Strength, psi (Sec. 195.106(b))
t= Wall Thickness, in. (Sec. 195.106(c))
F= Design Factor, (Sec. 195.106(a))
E= Seam Joint Factor, (Sec. 195.106(e))
T= Temperature Derating Factor, (Sec. 195.102)
D= Nominal Outside Diameter, in.

(1) Maximum Design Pressure of Pipeline Segment

$$P_{Pipe\ Design} = \frac{2 \times 35000 \times 0.438 \times 0.72 \times 1.00 \times 1.000}{10.750}$$

$$P_{100\%\ SMYS} = \frac{2 \times 35000 \times 0.438 \times 1 \times 1.00 \times 1.000}{10.750}$$

$P_{Pipe\ Design}$ = **2054** psi

$P_{100\%\ SMYS}$ = 2852 psi		$P_{72\%\ SMYS}$ = 2054 psi		$P_{40\%\ SMYS}$ = 1141 psi	
$P_{80\%\ SMYS}$ = 2282 psi		$P_{60\%\ SMYS}$ = 1711 psi		$P_{30\%\ SMYS}$ = 856 psi	
$P_{75\%\ SMYS}$ = 2139 psi		$P_{50\%\ SMYS}$ = 1426 psi		$P_{20\%\ SMYS}$ = 570 psi	

(2) Maximum Design Pressure of Components

600 Series Components	1440	psi
		psi
		psi
		psi
		psi

$P_{Component}$ = **1440** psi

(3) Pressure Test

$P_{80\%\ of\ TP}$ = **1728** psi

(4) Segment MOP = **1440** psi

(5) OVERALL PIPELINE MOP = **1440** psi

(6) MOP % of SMYS 50.49%

CPF 5-2008-7002M
Line 5

Integrity Management Plan
Hazardous Liquid Pipelines
Element #7: Program Evaluation

Ref: 49 CFR 195.452(f)(7) & (k)	Updated: Sept 2008

In This Element:

7.1 Summary of Program Evaluation Requirements [195.452(k)]

After developing the IMP program, an operator must include methods to measure whether the program is effective in assessing and evaluating the integrity of each pipeline segment and in protecting the high consequence areas.

7.2 Types of Performance Measures

The performance measures required will depend on an understanding and analysis of the failure mechanisms or threats to integrity of each pipeline segment. The Company will select a set of measurements to judge how well its program is performing. The Company's objectives for its program are to ensure public safety, prevent or minimize leaks and spills and prevent property and environmental damage. This IMP program contains many elements. Therefore, several performance measures will be used to measure the effectiveness.

Performance measures show how a program to control risk on pipeline segments that could affect a high consequence area is progressing under the integrity management requirements. Performance measures generally fall into three categories:

1. Selected Process Measures–Measures that monitor the surveillance and preventive activities the Company has implemented. These measures indicate how well an Company is implementing the various elements of its integrity management program.

2. Deterioration Measures–Operation and maintenance trends that indicate when the integrity of the system is weakening despite preventive measures. This category of performance measure may indicate that the system condition is deteriorating despite well executed preventive activities.

3. Failure Measures–Leak History, incident response, product loss, etc. These measures will indicate progress towards fewer spills and less damage.

Internal vs. External Comparisons.

Internal versus external comparisons show how a pipeline segment that could affect a high consequence area is progressing in comparison to the Company's other pipeline segments that are not covered by the integrity management requirements and how that pipeline segment compares to other operators' pipeline segments.

1. Internal–Comparing data from the pipeline segment that could affect the high consequence area with data from pipeline segments in other areas of the system may indicate the effects from the attention given to the high consequence area. Note, if there no other non-HCAs segments, then no internal measures will be used.

2. External–Comparing data external to the pipeline segment (e.g., OPS incident data) may provide measures on the frequency and size of leaks in relation to other companies.

7.3 Performance Measures Process

Once per calendar year, not to exceed 18 months, the Company will collect performance information and evaluate the effectiveness of its integrity assessment methods, and its preventive and mitigative risk control activities, including repair. The Company will also evaluate the effectiveness of its management systems and processes in supporting integrity management decisions. In addition, MOC will be utilized to initiate performance evaluation of the IMP program when appropriate.

The company will defined performance goals that address IM Program areas as well as segments specific issues related to the operator's unique operating environment such as an increase in the number, and depth, of corrosion related anomalies, an increase in the threat of mechanical damage due to an increase in one calls, a change in operations resulting in an increase in pressure cycles, an increase in the number of crack anomalies, etc. See IMP data binder or IMP files for details. The company will also bench-mark company performance using data from outside the company. For example, Western Region Pipeline Operators(WRPO), agency reports, and Pipeline Association for Public Awareness (PAPA).

The Company expects the IMP will evolve and improve as experience is gained, and measurement of whether the program is effective is important in guiding that evolution. A combination of performance measures and system audits will be implemented to evaluate the overall effectiveness of the IMP program.

Ultimately, the performance measurement of the Company's integrity management program is the degree to which unintended releases are eliminated. The Company will have a minimum of ten (10) performance measures. These ten (10) performance measures shall include a distribution of leading, lagging, and deterioration measures. These ten (10) performance measures shall be based on an understanding of the failure mechanisms or threats to integrity for each pipeline system operated. The distinction between many of these measures will not always be clear.

7.4 List of Potential Performance Measures

Below is a list of potential performance measures the Company will use in measuring the effectiveness of the integrity management program. Table 7-1, located at the end of this IMP element section, includes more examples of performance measurement categories that may be used by the Company. The IMP records binder/files contains the Company's IMP list of selected performance measures.

Process Measures (Leading)

- A performance measure goal that documents the percentage of integrity management activities completed during the calendar year.
- A performance measure goal to track and evaluate the effectiveness of the Company's community outreach activities.
- A performance measure based upon internal audits of the Company's pipeline system per 49 CFR Part 195.
- A performance measure based upon external audits of the Company's pipeline system per 49 CFR Apart 195.
- A narrative description of pipeline system integrity, including a summary of performance improvements, both qualitative and quantitative, to the Company's integrity management program, prepared periodically.
- A performance measure based on operational events (e.g., relief occurrences, unplanned valve closures, SCADA outages, etc.) that have the potential to adversely affect pipeline integrity.
- A performance measure goal to measure the quality of information from in-line inspection tools

- A performance measure goal for management and analytical processes. (e.g., Is the risk assessment process failing to identify problem areas on the line?)
- A performance measure goal to analyze failures and near-misses and determine if these occurrences being critically examined and determine if lessons learned are being implemented

Deterioration Measures

- Aerial patrol with no one call
- Pig run with indicated corrosion
- Number of near misses reported

Failure Measures (Lagging)

- A performance measure goal to reduce the total volume from unintended releases with an ultimate goal of zero
- A performance measure goal to reduce the total number of unintended releases (based on a threshold of five gallons) with an ultimate goal of zero
- Trending of equipment or material failures as a means to evaluate pipeline deterioration (an indicator of the end of useful life of materials and components), including a method to establish the magnitude of trends that represent normal fluctuations versus significant deviations (i.e., significant enough to warrant corrective action)
- Trending of leading indicators such as inadvertent over-pressurization, right-of-way encroachments without one-call notification, SCADA outages, operation of overpressure or other safety devices, etc.

7.5 Program Evaluation Using Audits

Audits of integrity management programs are an important element of evaluating program effectiveness and identifying areas for improvement. Audits may be performed by personnel within the organization (self assessments), by auditors from outside organizations (third party consultants), or by agencies (PHMSA or CSFM). The IMP records binder/files contains the Company integrity management program audit goals and results.

The scope of the audits will be threefold. First, process activities required by 49 CFR 195 will be reviewed using the OPS protocol checklist found on the OPS website. The second audit type will be a complete review of the integrity management program to ensure all activities are performed accurately and in a timely manner. Lastly, the audit review shall include a review of the performance measures to determine if they should be updated to more accurately measure the program.

The company will develop goals for the audit program and continuous improvement of the integrity management program. The IMP Leader will ensure audits are conducted at least once every three years. The IMP Leader will also ensure audit findings are tracked and remedied in a timely manner.

Additional audits/program evaluations may be initiated due to management of changes issues like change in management or key IMP personnel, or when key operating parameters change. See company management of change procedures.

7.6 Communication of Program Evaluation

Integrity management program evaluation results will be distributed to all IMP team members and any other appropriate personnel. Communication shall include prioritized evaluation results and action taken to address the issues. The Operations Manager shall be notified immediately of any significant evaluation result. The Operations Manager will ensure evaluation issues are addressed in a timely manner.

The IMP procedures and process will be evaluated each year by use of the agenda's. During the IMP agenda reviews, IM team members will be asked for improvements to the process and procedures. These improvement ideas will be documented on the action item list and distributed as described above.

7.7 Use of Root Cause Analysis

The company root cause analysis/failure investigation procedures will be used to help determine causes of failures and make improvements in the IMP program.

7.8 Implementation of Element #7

The Company will use the attached agenda, "LIQ IMP element #7, Program Evaluation agenda and action items", for implementation of this element. This review will be conducted once per calendar year not to exceed 18 months.

7.9 Records

Document using one or more of the following:

- Performance Measures and review
- Audits reports (internal, third party, agency)
- Decision processes, rational, and assumptions
- Communication of program evaluation
- Root cause analysis reviews and conclusions
- Company performance goals, including segment specific if appropriate

7.10 Related References and Documents

1. 49 CFR 195.452(f)(7) & (k)

2. API #1160, Managing System Integrity for Hazardous Liquid Pipelines, Section #13, Program Evaluation, pages 36-40, 1st Edition, November 2001

3. OPS Frequently Asked Questions (FAQs):
   Section #10, Inspection and Enforcement, Sept 17, 2007
   Section #11, State Roles, Intra State Lines, Sept 17, 2007

4. OPS IMP Protocols
   Program Evaluation, Section #8, Oct 2006

5. Appendix C to Part 195, Guidance for Implementation of Integrity Mgmt Program: Section #5 – Methods to Measure Performance, pages 7-8

Table 7-1 Potential Performance Measurement Categories

	Leading		*Lagging*
Failure Mechanism	**Process Measures**	**Deterioration Measure**	**Failure Measures**
	Third-party Damage		
Third-party excavation, construction or other work at the time of failure	• Compliance with 195.422 • Compliance with "common ground" • Number of one-calls	• Aerial patrol reports with no one-call • Inadequate one-call follow-up • Pig run with indicated damage	• Leak due to TPD
Third-party excavation, construction or other work activity occurring at some time prior to failure		• Aerial patrol reports with no one-call • Inadequate one-call follow-up	• Pig run with indicated damage • Notification of pipeline damage by TPD
Other TPD, including vandalism, third-party vehicle contact with facility, and other intentional or unintentional acts	• Compliance with 195.442	• Aerial patrol reports • Pig run with indicated damage	• Leak due to TPD
	Corrosion		
External corrosion	• Compliance with 195.236,238,242, 244, 416 • Compliance with NACE RPO 169	• Pig run with indicated corrosion • Annual cathodic protection exception reports • Close interval surveys • Interference testing	• Leak due to corrosion
Internal corrosion	• Water content • H2S content • CO2 content	• Coupon tests • Pig run with indicated corrosion • Time interval between scraper runs	• Leak due to corrosion
	Material Failures		
Pipe materials, pipe seam, pipe weld or repair weld failure	• Review of ;material properties	• ILI tool run results • Hydro-test blowouts	• Leak or rupture

Table 7-1 Potential Performance Measurement Categories (cont.)

	Leading		*Lagging*
Failure Mechanism	**Process Measures**	**Deterioration Measure**	**Failure Measures**
	Equipment Failure		
Equipment malfunction or failure of non-pipe component	• Inappropriate specifications • Inappropriate materials • Efficiency testing of pumps • Maintenance training • Root cause failure analysis for systemic problems • Maintenance procedures	• Testing of control valves • Testing of high pressure shutdown devices • Testing of relief valves • Corrosion failure • API 653inspections • API 570 inspections	• Leaks due to gasket and packing failures • Leaks due to tank failure • Sump tank leaks
	Operational Error		
Excavation or physical damage to facility or pipeline by operator or operator's contractor	• Proper training • Internal one-calls	• Number of near misses reported	• Leaks • Pipe damage from pig run
Valve left or placed in wrong position		• Relief valve failure • Contamination	• Over pressure • Leaks
Pipeline or equipment over pressured	• Compliance with 195 • Training program reviews	• Number of relief valves operating	• Leak
	Motor vehicle		
Tank overfilled	• Oper. procedures are adequate • Shipper schedule changes or unscheduled deliveries	• Alarm maintenance	
Other human error		• Isolation of relief valves and shutdown devices for long periods of time	• Leaks
	Natural Forces		
Cold Weather			
Heavy rains/flooding	• Water crossing inspections	• Exposed pipes • Washout	• Rupture
Lightning	• #of station shutdowns due to ground faults		• Fire
Earth movement	• # of earthquakes	• Ground sloughing	• Rupture
	Other		
Other			
Other			
Other			

CPF 5-2008-7002M
Line 6

Integrity Management Plan
Hazardous Liquid Pipelines
Record Keeping

Ref: 49 CFR 195.452, 195.450, 195.6	Updated: Sept 2008

General

The purpose of this procedure is to provide guidance for recordkeeping of IMP program documents. Maps, drawings and records shall be readily available to any person requiring these documents to perform their pipeline duties.

List of IMP Required Records:

The table in the R&Rs tab shows all the data and records required by this IMP program.

Process

The appropriate person, as defined in the IMP roles and responsibilities tables, will generate the record as required and place in the appropriate DOT file. All records and data should be reviewed for accuracy by the IMP Leader or appropriate person.

Record Information

When changes are made to the IM program, the changes will be documented and include the reason for the change.

Record Retention:

Each record will be retained for the time noted on the file index table located at the end of this section. Generally, routine operations, maintenance, and operator qualification records will be kept for a minimum of five years. Construction, repair, and corrosion records will be kept for the life of the pipeline.

Records Location:

Generally, routine operations and maintenance records will be kept in a pipeline system DOT file. Records that require retention for life of the pipeline will be kept in the appropriate file location as noted in the DOT File Index. New construction, repairs, and other large projects should be combined into a project binder or file for placement into the DOT filing system.