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October 8, 2007

Chris Hoidal, P.E.
Director, Western Region
Pipelines and Hazardous Materials Safety Administration
12300 West Dakota Avenue, Suite 110
Lakewood, CO 80228

Re: Notice of Amendment - **CPF 5-2007-5021M**

Dear Mr. Hoidal:

BP Pipelines respectfully submits the following responses on behalf of BP Exploration Alaska (BPXA) to your "Review of NOA Response" (dated July 3, 2007), and received by BPXA on July 10, 2007, that resulted from the focused IMP inspection in Anchorage, Alaska on March 21 and 22, 2007.

As you will note, our response includes final language on how each item is being addressed. These updates will be posted in the next revision of the BPXA IMP which is in process. The apparent inadequacies found within BPXA's plans or procedures, as noted in your original letter, are described below, along with BPXA's responses.

If you have any questions pertaining to this matter, please contact Dave Barnes at (630) 836-3435.

Sincerely,

Gerald E. Schau
HSSE & Integrity Manager

Attachments:
1. *STP 32-200 Specification for On-Line Inspection (ILI) Data Evaluation and Resulting Repair Program Procedures for ILI Repair Projects (liquids)*
2. *Endicott/Badami Leak Detection Baseline Assessment Report*

cc: Sandy Stash - BPXA
Doug Suttles - BPXA
Tony Brock – BPXA
Angus Walker – BPXA
Bud Fackrell – BPXA
Mike Utsler - BPXA

Item 1.

§452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program:
(1) A process for identifying which pipeline segments could affect a high consequence area.

The review of the Badami Fate and Transport Analysis indicated that absorption was taken into account for overland spread. While it has been shown through experience that releases in winter can be partially contained by snow and cold temperatures, the assumption that releases in summer can be mitigated by absorption should be justified.

The Fate and Transport Analysis used current operating flow rates to calculate release volumes along each pipeline. The BPXA IM Plan should describe the process for identifying changing operating conditions that might impact the F&T analysis and how these changes will trigger new F&T analyses.

BPXA Response:
BPXA has incorporated the following technical justification for the absorption volumes into the assumption basis for the Fate and Transport (F&T) analysis to provide a more comprehensive understanding of the basis behind this work. The language below has been inserted in each of the F&T Analysis Reports in Attachment A – Analytical Methods.

The basis for the tundra absorption volume is provided in a report titled "North Slope Pipeline Discharge to Land Analysis" prepared for BP Exploration (Alaska) Inc. (BPXA) and PHILLIPS Alaska, Inc. (PAI) in August, 2002 by SLR Alaska and SL Ross[(3)]. A literature search of tundra sorption capacities for the arctic conducted for the study revealed a range of values. The study cites an Alaska Department of Environmental Conservation (ADEC) study of historic North Slope spills conducted by Behr-Andres et al. in 2001[(4)]. That research indicated that larger spills tend to cover between 0.1 and 0.4 square feet of tundra per gallon of crude oil. This is equivalent to 2.5 to 10 gallons of crude oil per square foot of tundra. Additionally, the PAI Oil Discharge Prevention and Contingency Plan (ODPCP) for the Kuparuk River Unit in 2001 as well as BPXA's Milne Point and Badami ODPCPs reference accepted tundra retention values of 3 gal/ft^2 of crude oil (1.15 times the lower end of the range identified by ADEC in 2001) which was used as the absorbed volume for the F&T analysis. In addition to the crude oil volume absorbed by the tundra vegetation, another fraction of spilled oil is contained on the surface of the tundra. The Northeast National Petroleum Reserve-Alaska Environmental Impact Statement (EIS) conducted by the U.S Department of Interior (USDOI) in 1998[(5)] states that during the summer months, flat coastal tundra develops a dead-storage capacity averaging 0.5 to 2.3 inches. Converting to a volume, this adds approximately 0.29 to 1.42 gal/ft^2 of crude oil storage capacity to North Slope tundra. As such, *a dead storage capacity of 0.4 gal/ft² (1.15 times the lower end of the range identified by USDOI in 1998) was added to the absorbed volume for a total tundra absorbed volume of 3.4 gal/ft².*

The basis for the snow absorption volume is derived from Volume 1 of the Alaska Clean Seas Technical Manual(6). Recovery Tactic R-3 lists the holding capacity of heavily oiled snow as 3.7 gal/ft³ of snow. It is estimated that the average depth of snow cover on the North Slope is between 8 to 12 inches with 10 inches being used as a basis for 3.0 gal/ ft² being used in this model.

Reference Citations (from above text)

(3) *SLR Alaska, Inc and SL. Ross Environmental Research Ltd., 2002. "North Slope Pipeline Discharge to Land Analysis". Prepared for PHILLIPS Alaska, Inc. and BP Exploration (Alaska) Inc. August.*

(4) *Behr-Andres, C.B., Wiegers, J.K., Forester, S.D., Conn, J.S. 2001. ADEC Tundra Spill Cleanup and Remediation Tactics: A Study of Historic Spills and Literature. May.*

(5) *U.S. Department of the Interior, Bureau of Land Management. 1998. Northeast National Petroleum Reserve – Alaska, Final Integrated Activity Plan/Environmental Impact Statement, Vol. 1. BLM/AK/PL-98/016+3130+930, Alaska.*

(6) *Alaska Clean Seas, Revised 2007. Alaska Clean Seas Technical Manual – Volume 1: Tactics Descriptions. March.*

Also, a set of criteria is being added to the IM program in Section 1.04, stating the following:

Any change in operation or physical configuration of a pipeline that would cause an annual pipeline throughput increase of 20% or more would trigger the re-evaluation of the need for a new F&T analysis. Such changes would include an increase in flow rate, increase in pipeline diameter, the addition to pipeline to the system, or the deletion of valves.

Item 2.

§195.452 (b) ***What program and practices must operators use to manage pipeline integrity?*** **Each operator of a pipeline covered by this section must:**
(3) Include in the program a plan to carry out baseline assessments of line pipe as required by paragraph (c) of this section.

§195.452 (c) ***What must be in the baseline assessment plan?*** **(1) An operator must include each of the following elements in its written baseline assessment plan:**
(i) The methods selected to assess the integrity of the line pipe. An operator must assess the integrity of the line pipe by any of the following methods. The methods an operator selects to assess low frequency electric resistance welded pipe or lap welded pipe susceptible to longitudinal seam failure must be capable of assessing seam integrity and of detecting corrosion and deformation anomalies.
(A) Internal inspection tool or tools capable of detecting corrosion and deformation anomalies including dents, gouges and grooves;
(B) Pressure test conducted in accordance with subpart E of this part; or
(C) Other technology that the operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 90 days before conducting the assessment, by sending a notice to the address or facsimile number specified in paragraph (m) of this section…(iii) An explanation of the assessment methods selected and evaluation of risk factors considered in establishing the assessment schedule.

The dent excavation spreadsheet reviewed during the inspection did not contain the recent ILI information for the EOA 34 inch pipeline. The results of this assessment should have been included in the spreadsheet for completeness.

An updated sheet was provided at the end of the inspection. This provided information on a future ILI inspection to be performed 7/2007 on the EOA FS 2 to FS 1 section. This section has been taken out of service and will be replaced by a new pipeline. The update did not include the results of dent investigation for the EOA 34 inch FS 1 to Skid 50 ILI run performed in October, 2006. A process for creating and populating your spreadsheets should include a completeness check or explanation for missing information.

BPXA Response:
A revised "dent log" spreadsheet was attached to BP's June 4, 2007 response that provided closure to this item. Also, a process for maintaining this log has been developed and fully described in the revised IMP in Section 3.04 and re-stated here:

*The **Integrity Analyst/Pipeline Inspection Authority** will maintain the "dent log" spreadsheet and will update this information after assessment results have been completed for each ILI.*

Item 3.

§452 (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)

§452 (h) (2) *Discovery of a 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 BPXA IM Plan states that indications >40% wall loss will be evaluated. These indications are not listed as "other" repair conditions in Protocol 4.01 or in BPNA procedure 200. BPXA should define the criteria that will be used to determine if any wall loss indications >40% must be repaired. This criteria needs to be incorporated into all applicable repair procedures.

The relationship of existing repair procedure 00090 and its proposed replacement -BPNA procedure 200 - to the Tier 2 OMER repair procedure is not clear. The Tier 2 OMER procedure does not contain all of the IM rule repair requirements for corrosion. In addition, it appears that procedure 00090 Sections 6.2 and 6.3 allow clamp on sleeves to be used to repair leaks due to corrosion whereas the Tier 2 OMER procedure does not. BPXA needs to ensure that all repair procedures accurately and completely address IM repair criteria and allowable repair methods. All regulatory requirements should be included on the final process.

BPXA Response:
The bulleted items below address the three areas identified above which include: clarification on the percent of wall loss requiring evaluation; ILI data evaluation criteria, and; incorporated repair criteria.

- *BPXA has reviewed the evaluation requirement for indications >40% wall loss as stated in the December 29, 2006 version (Rev 5) of the IMP, Section 3.03, 4th bullet item, and has revised this language to state:*
  BPXA does a statistical sampling of suspected anomalies. Every ILI anomaly indicating over 50% wall loss is inspected.
- *BP Pipelines (North America) procedure STP 32-200 (Specification For In-Line Inspection Data Evaluation and Resulting Repair Program Procedures For ILI Repair Projects – Liquids) has been updated to apply to Alaskan operations and this redlined version is attached for your reference. STP-32-200 outlines ILI requirements including a description of timed repair conditions and has been incorporated by reference into the BPXA IMP. This document is a controlled*

document and is undergoing the Management of Change process for revision updating.

- *The criteria used to determine repairs are contained in* *Criteria for Pipeline Intervention and Repair CRT-AK-43-53* *which supersedes* *STP-00090's sections on repairs and has been incorporated by reference into the BPXA IMP. Both* *CRT-AK-43-53* *and* *OMER Tier 2* *allow mechanical clamps to be utilized on corrosion leaks as a temporary repair method.*

Item 4.

§195.452 (f) *What are the elements of an integrity management program?* (6) Identification of preventive and mitigative measures to protect the high consequence area (see paragraph of this section)

§195.452 (i) *What preventive and mitigative measures must an operator take to protect the high consequence area? (1) General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.

> The BPXA IM Plan must address how their proposed improvements to Leak Detection addresses the eight required evaluation factors of 195.452 (i)(3). The IM Plan should also address how and when future evaluations of the Leak Detection systems will be performed.

BPXA Response:
Section 6.04 of the IMP is being revised to add the following language:

> *Leak Detection Baseline Assessment reports are conducted to provide an evaluation of the current pipeline leak detection capabilities as compared to the eight required evaluation factors as described in 49 CFR 195.452(i)(3). As part of each report, current improvement initiatives and possible enhancements are considered. Also, a review of leak detection system baseline assumptions are conducted at annual risk review meetings. Further, as part of the state of Alaska regulatory requirements, BPXA performs a Best Available Technology (BAT) review for leak detection when Oil Discharge Prevention and Contingency Plans (ODPCP) are renewed. As part of that process, the Leak Detection system evaluation and conclusions are recorded in the current ODPCP.*

As a sample, the Endicott & Badami Leak Detection Baseline Assessment Report is attached for your reference.

Item 5.

§195.452 *What preventive and mitigative measures must an operator take to protect the high consequence area?* (3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider the following factors - length and size of the pipeline, type of product carried, the pipeline's proximity to high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

The BPXA IM Plan must address how their proposed improvements to Leak Detection addresses the eight required evaluation factors of 195.452 (i)(3). The IM Plan should also address how and when future evaluations of the Leak Detection systems will be performed.

Section 6.04 of the Plan should fully describe current leak detection systems or reference a document where these descriptions are provided.

BPXA Response:
The BPXA IM Plan has been modified as described in the response to Finding 4 to address the evaluation factors in 195.452 (i)(3).

This revised Section 6.04 of the Plan includes a reference to the applicable Oil Discharge Prevention Contingency Plan (ODPCP), which fully describes the current leak detection system for each respective pipeline. As an example, the applicable sections of the ODPCP sections from the Northstar Pipeline are included below:

Northstar Example:
2.1.7 Leak Detection, Monitoring, and Operating Requirements for Crude Oil Transmission Pipelines [18 AC 75.055]
The crude oil transmission pipeline is equipped with a system capable of detecting a leak with a daily rate equal to one percent of daily throughput, as required by 18 AAC 75.055(a)(1). Flow is verified at least once every 24 hours, as required by 18 AAC 75.055(a)(2). The flow of incoming oil can be stopped within one hour after detection of spill, as required by 18 AAC 75.055(b). The control board operator proceeds through a series of steps to determine the cause of the alarm. Field surveillance is requested if the alarm cannot be explained as a non-leak event. Verification of a leak would facilitate pipeline shut in. See Section 2.5.6. ADEC is notified in writing within 24 hours if a significant change occurs in or is made to the leak detection system and if, as a result of the change, the system does not meet the "equal to not more than one percent of daily throughput" criterion [18 AAC 75.475(d)(1)].

4.10 LEAK DETECTION IN CRUDE OIL TRANSMISSION PIPELINES [18 AAC 75.425(e)(4)(A)(iv)
As required by 18 AAC 75.425(e)(4)(A)(iv), a best available technology (BAT) review has been made for leak detection technologies applicable to the Northstar pipeline. These technologies are as follows:

- *Mass Balance Line Pack Compensation (MBLPC),*
- *Pressure Point Analysis (PPA),*
- *Mass Balance (MB),*
- *Real Time Transient Model (RTTM),*
- *Negative Pressure Wave Monitoring (NPWM) (acoustic monitoring system),*
- *Acoustic Emissions (AE) Monitoring based on measured sound data, and*
- *LEOS leak detection and location system based on molecular diffusion.*

The rationale in determining the most appropriate leak detection system for North Slope transmission lines is based on operation philosophy, in addition to criteria stipulated in the BAT analysis. First, there must be redundancy (i.e. reliance will not be placed on a single leak detection system). The technology must be state-of-the-art and capable of immediate detection of a sudden large volume loss of product as well as detection of a low threshold chronic (pinhole) leak. The system must also be commercially available, in use on similar pipeline systems, be composed of two leak detection systems that are readily integrated with each other, and must be available from a vendor with a proven track record. To obtain the US Army Corps of Engineers Permit, the Northstar Project was required to meet the threshold leak volume stipulated by the Corps (Stipulation 18) of 32.5 barrels per day. The stipulation applied to the subsea portion of the pipeline. After researching the best available technologies, the LEOS leak detection and location system was selected for this purpose. The vendor FRAMATOMEANP has demonstrated in field tests the ability of LEOS to detect and locate a very small hydrocarbon leak. The specification for the Northstar subsea pipeline is to be able to detect a leak of approximately 1 barrel in a 24-hour period, and to be able to locate it within 50 meters (approximately 5 percent of the 10 km length). In investigating the various leak detection systems available and determining the best application for the Northstar pipeline, it became apparent that each leak detection system has its associated strengths and weaknesses that depend on the specific pipeline operating characteristics. The type of system selected depends on the combination of several technologies including flow measurement, instrumentation, communications, computer hardware and software, and ultimately experience in operating a system under similar circumstances (i.e., similar pipeline flow conditions). In consideration of the environmental conditions at Prudhoe Bay and the flow conditions in the pipeline; it is essential that the selected system have an established and verifiable track record in the North Slope crude oil pipelines. In addition, the chosen system must be redundant (i.e., reliance is not placed on a single leak detection system), the technology must be state-of-the-art and capable of immediately detecting a sudden large volume loss, and it should be capable of detecting a low threshold chronic leak.

Alaska Department of Environmental Conservation (ADEC) renewed ODPCP approvals for BPXA's North Slope facilities in 2007. As part of the renewal process, all sections of the ODPCPs were evaluated for compliance with 18 AAC 75 regulations, including BAT requirements. These plans are also approved by applicable federal agencies with Oil Pollution Act of 1990 (OPA 90) jurisdictions.

Item 6.

§195.452 (f) An operator must include, at minimum, each of the following elements in its written integrity management program: (5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section); §195.452 (g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure.
§195.452 (j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?* (1) General. After completing the baseline integrity assessment, an operator must continue to assess the line pipe at specified intervals and periodically evaluate the integrity of each pipeline segment that could affect a high consequence area.
(3) *Assessment Intervals.* An operator must establish intervals not to exceed five (5) years for continually assessing the line pipe's integrity. An operator must base the assessment intervals on the risk the line pipe poses to the high consequence area to determine the priority for assessing the pipeline segments. An operator must establish the assessment intervals based on the factors specified in paragraph (e) of this section, the analysis of the results from the last integrity assessment, and the information analysis required by paragraph (g) of this section.

Periodic evaluation is considered to be an ongoing data integration process that takes into account changing conditions on a pipeline that may warrant a change in reassessment schedules. The IM Plan states in Section 7.01/7.02 "If assessment results or other factors warrant, higher risk areas may require more frequent evaluation". The IM Plan needs to provide more detail as to when evaluations will be performed, by whom, which risk factors will be evaluated, and how re-assessment intervals will be changed.

BPXA Response:
The revised IMP, Section 7.02, includes detailed criteria for determination of the frequency of pipeline condition assessment and identifies trigger points for reassessment, and is consistent with the BP Pipelines (North America) process. These criteria include the factors delineated in 195.452(e). This new BPXA IMP section 7.02 and flow chart are included here for reference:

7.02 Re-assessment Intervals (49 CFR 195.452(j)(2) & (3))

<u>PRELIMINARY DETERMINATION</u>

Re-assessment methods and intervals are based on the information obtained through the Integrity Assessment results, Information Analysis, historical and current integrity information, as well as operational needs. The scheduled re-assessments do not exceed five years.

<u>SECONDARY/FRA DETERMINATION</u>

If assessment results, FRA conclusions or other risk factors warrant, higher risk areas may require more frequent evaluation. The FRA is conducted annually to make this determination.

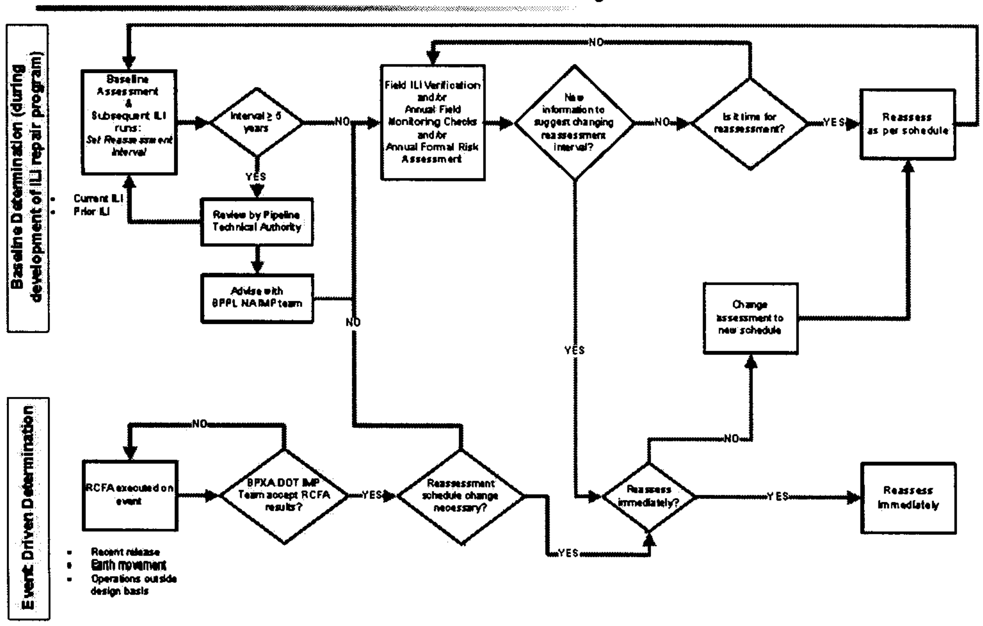
The FRA will involve a team review (which includes the PTA, Corrosion SME's and operations representatives) of the considered information which will include basic data (including but not limited to: operating conditions, pipe properties, VSM stability, hydrotest) and data indicating threats to the pipe/pipeline (including but not limited to: ILI data, results, annual cathodic protection surveys, third party damage, right-of-way encroachment activity, new HCAs). The review team is lead by an Pipeline Technical Authority and may include representatives from the engineering, CIC and field operations teams as appropriate. See Figure 7-1 Continual Process of Assessment & Evaluation for details.

EVENT DRIVEN DETERMINATION

*Numerous pipeline events can have immediate impact on the re-assessment interval. Events such as leaks, third-party strikes, flooding/erosion, or seismic activity all have potential to necessitate acceleration of a pipeline section assessment. All BPXA personnel (through the execution of routine project, operation, and maintenance activities) shall monitor pipeline conditions to identify these types of events and report (enter) them in TR@CTION. The **Pipeline Technical Authority** shall review these events and determine if changes to the current re-assessment interval is warranted. Changes to re-assessment intervals will be documented in the **IMP Implementation Log** along with explanation for the change.*

Figure 7.02 Reassessment Interval Determination Processes - is the algorithm used to determine the reassessment interval.

Reassessment Interval Determination Processes *Figure 7.02*



Item 7.

§195.452 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);
§195.452 (k) *What methods to measure program effectiveness must be used?* 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.

PHMSA recognizes that the BPXA IM program is in a state of transition and that BPXA has chosen to focus on Key Performance Indicators that measure implementation process. However, BPXA needs to emphasize development of Key Performance Indicators (KPIs) that measure the effectiveness of the IM program. BPXA should use the characteristics of an effective program provided in Protocol 8.02 and the performance metrics identified in API 1160 to develop these KPIs.

BPXA Response:
Section 8.02 of the IMP is being revised to add the following language:

KPIs will be reviewed during the annual program evaluation meeting and will focus on program effectiveness and guidance in API 1160.

BPXA Integrity Management Plan
Leak Detection - Baseline Assessment
Endicott & Badami Sales Oil Pipelines

Description: This assessment evaluates the current pipeline leak detection capabilities to ensure DOT regulatory compliance.

Applies to: Endicott & Badami Oil Sales Pipelines

References:
49 CFR 195.452(i)(3)
US DOT - PHMSA – IMP Inspection Protocols
BPXA Integrity Management Plan – Section 6.04 Leak Detection
Endicott/Badami - Oil Discharge Prevention and Contingency Plan
- Sections: 2.1.7 and 4.10

Contents:
Summary, Criteria, Description, Conclusion, Recommendation
Appendix I: Leak Detection Checklists (2)
Appendix II: Pipeline Leak Detection System - Description
Appendix III: Expanded References
Part A) CFR 195.452(i)(3)
Part B) US DOT - PHMSA – Integrity Management Program Inspection Protocols
Part C) Hazardous Liquid Leak Detection – Techniques & Processes, Report No. DTRS56-02-D-70037-01
Part D) BPXA Integrity Management Plan rev 5, Section 6.04 - Leak Detection
Appendix IV: Endicott/Badami Oil Sales Pipeline map

Related Materials:
Endicott/Badami - EFRD Baseline Assessment
Endicott/Badami - Fate and Transport Analysis Report, December 2006
Endicott/Badami - Risk Assessment Report, December 2006
DOT Covered Task 44. CPM Leak Detection
API 1130 – Computational Pipeline Monitoring for Liquid Pipelines
Hazardous Liquid Leak Detection – Techniques & Processes
EFA Leaknet Brochure

EFA LeakNet Brochure.pdf

Attachment 1: *EFA Leaknet*™ Brochure

Authority: BPXA Pipeline Technical Authority – Glen Pomeroy

Date: September 17, 2007

Summary:
The whole length of the Endicott (25.6 miles) and Badami (25 miles) Oil Sales Lines could affect a HCA. As a result they come under the requirements of 49 CFR 195.452. In November 2006 a Formal Risk Assessment (FRA) was carried out on these lines as per the requirements of the BPXA Integrity Management Plan. Two Leak Detection checklist templates were prepared in advance for each line with the goal to be filled in during that meeting. However, the final results of the Fate & Transport study and upgrades to the leak detection system alarm set points had not been completed at that time so all the questions on the checklists could not be completed at the meeting. This is a follow-on report to complete the remaining parts of the Leak Detection Baseline Assessment for this pipeline system.

In September 2007, a screening evaluation of the leak detection capabilities on this pipeline system was completed by the Pipeline Technical Authority (PTA) and a member of his staff.

Leak Detection Criteria:

- The Alaska Department of Environmental Conservation's (ADEC) detection requirement is 1.0% of daily throughput.
- The BP Pipelines North America (BPPL NA) requires additional screening criteria of 5% of average throughput over four hours.
- The DOT does not have an explicit criteria for detection levels but has a list of factors to be considered when evaluating pipeline leak detection systems in cases where the pipeline could affect a high consequence area (HCA). Those factors are incorporated into the two checklists contained in this assessment.

Leak Detection System: High Level Description *(for additional details see Appendix II)*
BPXA utilizes the following leak detection methods on its DOT regulated North Slope pipelines:

1) Physical inspection
2) Computational Pipeline Monitoring (CPM)
3) LEOS (for Northstar offshore only)

Conclusion:
Leak detection is a very important tool to minimize the consequences of a loss of containment. The leak detection systems currently in place meet or exceed all regulatory requirements. To ensure continuous improvement, BPXA periodically reviews advancements in leak detection technology as part of its Oil Discharge Prevention and Contingency Plan (ODPCP). The latest Endicott/Badami ODPCP update was in 2007.

Leak detection capabilities – current improvement initiatives under way:

- Continue to standardize leak detection procedures, operator training and capabilities across all BPXA operations on the North Slope
- Continue to look for new developments in technology as described in the Oil Discharge Prevention and Contingency Plans
- Continue with pipeline marking upgrades
- Continue to increase the usefulness of Forward Looking Infra Red (FLIR) technology
- Assure leak detection testing is taking place on schedule

Checklist 1 – DOT required Evaluation Factors

Leak Detection Checklist #1: DOT 49 CFR 195.452(i)(3) Leak Detection Evaluation Factors

DOT Factors	**Does current system incorporate/explain the following?**	**Where is the supporting data** (location)**?**	**SME** (contact person: name & title)
1. Length & size of the pipeline	Yes	Oil Discharge Prevention & Contingency Plan OMER	Mike Schoonmaker (AICE Engineering Team Lead)
2. Type of product carried	Yes	Oil Discharge Prevention & Contingency Plan	Mike Schoonmaker (AICE Engineering Team Lead)
3. Pipeline proximity to HCA	Yes	Fate & Transport Study	Glen Pomeroy (Pipeline Technical Authority)
4. Swiftness of leak detection	Yes	Oil Discharge Prevention & Contingency Plan	Mike Bronson (Crisis Management Coordinator)
5. Location of nearest response personnel	Yes	Oil Discharge Prevention & Contingency Plan	Mike Bronson (Crisis Management Coordinator)
6. Leak history	Yes	Oil Discharge Prevention & Contingency Plan	Mike Bronson (Crisis Management Coordinator)
7. Risk assessment results	Yes	Baseline Formal Risk Assessment Report *(2006)*	Glen Pomeroy (Pipeline Technical Authority)

Comments:
As part of the state of Alaska regulatory requirements, BPXA performs a *Best Available Technology* (BAT) review for leak detection when the Oil Discharge Prevention and Contingency Plans (ODPCP) are renewed. The Endicott/Badami pipeline was updated in June 2007. As part of that process the Leak Detection system was evaluated and the conclusions recorded in the latest ODPCP, excerpts of which are included in Appendix II of this report.

1. **Length & size of the pipeline** – the *EFA Leaknet[tm]* CPM model utilizes static volume and flow rates both of which are functions of the length and size of the pipeline.

2. **Type of product carried** – This pipeline transports a single product - crude oil. The CPM leak detection system utilizes temperature and pressure compensated custody transfer metering to adjust the fluid volume based on crude oil's characteristic response to temperature and pressure. Leak detection and spill response plans are designed around a crude oil leak for this line.

3. **Pipeline proximity to HCA** – this pipeline is in a DOT defined HCA, as a result a comprehensive pipeline *Integrity Management Plan, Oil Discharge Prevention and Contingency Plan,* a *Fate & Transport Study* and redundant leak detection systems combine to minimize the risk of a spill from this pipeline.

4. **Swiftness of leak detection** – the current leak detection capabilities on this line meet the criteria outlined earlier in this report – 1% of daily throughput and 5% of average throughput over four hours for Endicott. For the Badami pipeline, the current throughput is so low that current technology is not capable of accurately detecting a leak at these low levels within the timeframes above. Hence a leak would be detected for low volumes but over a slightly longer time frame.

5. **Location of nearest response personnel** – a comprehensive Oil Discharge Prevention and Contingency Plan for this pipeline is in place to minimize the consequence of a potential spill from this pipeline. Response personnel and equipment are located both at the Endicott Production facility as well as in Prudhoe Bay.

6. **Leak history** – there have been no reported leaks on this pipeline. Should a leak occur, a root cause analysis will be conducted. In addition to the BAT review required by ADEC, a review of the leak detection capability would be conducted in the event of a not detected leak that met the detection design parameters.

7. **Risk assessment results** – this baseline assessment report is written to satisfy one to the requirements of the BPXA DOT Integrity Management Plan. Performing Formal Risk Assessments on an annual basis is called for in that plan. A review of leak detection system performance is on the agenda for that meeting to ensure it is meeting expectations.

Leak Detection Checklist #2:
Because this pipeline is in a High Consequence Area, what are the possible enhancements that can be made to the current Leak Detection Systems, some examples are as follows (for more detail on these read Appendix III, Part C section 8 in this report):

1) *Improving measurement accuracy*
2) *Installation of additional sensors*
3) *Changing operating modes*
4) *Revising leak procedures*
5) *Improving operator training*
6) *Increasing frequency of manual methods (patrols)*

Comments:

1. **Improving measurement accuracy** – the meters currently installed allow the *EFA Leaknet*[tm] CPM model to discern very low threshold levels.

2. **Installation of additional sensors** – the number of meters currently installed successfully meet the manufacturers recommendations and exceed or meet regulatory requirements (e.g. state of Alaska).

3. **Changing operating modes** – this pipeline operates in a relatively simple manner: single input and output; single product; relatively steady flow; no slack-line conditions exist. No further work on this is suggested at this time.

4. **Revising leak procedures** – an initiative is already under way to standardize leak detection procedures across BPXA's North Slope operations. Progress on this will be reviewed in the annual risk assessments.

5. **Improving operator training** – it is recommended that leak detection training be standardized across BPXA's North Slope operations. Progress on this will be reviewed in the annual risk assessments.

6. **Increasing frequency of manual methods** – this pipeline is above ground. The majority of the line is accessible by road. As a result security drive-by patrols are performed at least 26 per year as per Table 2-7. for Endicott and 52 times per year for Badami. The current condition assessment from CIC based on ILI tool runs, and the current leak detection systems in place support the recommendation to keep the patrol frequencies at current levels.

Leak Detection System – Description Overview
BPXA relies on the following methods of leak detection on its DOT regulated Alaska North Slope pipelines:

1) Physical inspection
2) Computational pipeline monitoring (CPM)
3) LEOS (for Northstar offshore only)

1. Physical Inspections:
Whereas most pipelines are buried in the US, BPXA North Slope on-land pipelines are located above-ground on vertical support members (VSM). This makes visual inspection relatively easy compared to most other pipeline systems in other locations.

The following formal types of visual inspections are carried out depending on the local infrastructure (roads) and/or weather conditions:

1. Security drive-by
2. Aerial fly-by

2. Computational Pipeline Monitoring (CPM)
This pipeline has an EFA Technologies, ***LeakNet***tm pipeline leak detection & location system. This package integrates three complementary, fully independent methods of leak detection:

- Dynamic line monitoring
  - ***Pressure Point Analysis*** (***PPA***tm)
  - ***MassPack***tm
- Static line monitoring
  - Static – ***PPA***

Excerpts from **Endicott/Badami Oil Discharge Prevention & Contingency Plan** (May 2007)

- Section 2.1.7
- Section 2.5.6
- Section 2.5.7
- Section 2.5.8
- Section 4.10

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2.1.7 Leak Detection, Monitoring, and Operating Requirements for Crude Oil Transmission Pipelines [18 AAC 75.055]

The crude oil transmission pipeline is equipped with a system capable of detecting a leak with a daily rate equal to one percent of daily throughput, as required by 18 AAC 75.055(a)(1). Flow is verified at least once every 24 hours, as required by 18 AAC 75.055(a)(2). The flow of incoming oil can be stopped within one hour after detection of spill, as required by 18 AAC 75.055(b). The Control Board Operator proceeds through a series of steps to determine the cause of the alarm. Ground-based surveillance may be requested. Verification of a leak would facilitate pipeline shut in. See also Section 2.5.6.

ADEC is notified in writing within 24 hours if a significant change occurs in or is made to the leak detection system and if as a result of the change the system does not meet the "equal to not more than one percent of daily throughput" criterion [18 AAC 75.475(d)(1)].

2.5.6 Crude Oil Transmission Pipelines

The Endicott pipeline leak detection system monitors the crude oil transmission pipeline from the Main Production Island (MPI) to Pump Station 1 for a loss of fluid. The system has demonstrated the ability to detect a daily discharge equal to not more than one percent of daily throughput.

Additionally, as a voluntary measure, Security provides daily drive-by visual surveillance of the Endicott crude oil transmission pipeline. The Endicott pipeline route is entirely road-accessible, and therefore does not require aerial surveillance. Visual pipeline inspection is facilitated by the aboveground construction of the pipelines.

Leak detection for the Badami sales oil pipeline consists of weekly aerial visual inspection unless precluded by safety or weather conditions and monitoring of flow variations in the pipeline. At the Central Processing Facility, meters are installed on the A, B and C meter runs. The C Meter run provides metering flows less than 1,056 barrels of oil per day (bopd). A flow conditioner smoothes the oil flow upstream from the meter. At the Badami pipeline tie-in with the Endicott pipeline, the flow of oil from the Badami pipeline into the Endicott pipeline is measured with a sensing elements designed to handle flow rates up to 2,000 barrels of oil per hour (boph). Oil flow data are transmitted from the meter at Remote Terminal Unit No. 3 (RTU-3) to the Badami control room and then relayed to Endicott via the process control network. The meter supports API equations for net oil calculations. The data also are used for leak detection in the Ed Farmer and Associates (EFA) Leak Net host computer at Endicott. MassPack segment 5 performs the oil mass balance calculations for the pipeline segment from Badami to RTU-3.

Custody transfer metering systems on the Endicott MPI, at Badami and at Pump Station 1 of the TAPS measure volumes accurately and enhance the performance of the leak detection system. The systems provide corrected flow data to the LeakNet System via connected Allen-Bradley PLC-5s on the MPI, Badami, and at Pump Station 1. Pressure, temperature, and instantaneous flow information is provided from both the MPI and Pump Station 1 locations.

The Endicott/Badami pipeline system to Pump Station 1 is monitored using an EFA LeakNet system. Currently only the MassPack algorithm is used for leak detection.

The EFA Mass Pack software performs conventional mass balances over 1 minute, 1 hour, and 24 hours with three corresponding alarm thresholds. The system displays a volumetric flow balance and acquires total inlet and outlet crude flow data every minute. Calculations are carried out as shown in Table 2-6.

TABLE 2-6: Volumetric Flow Balance Calculations

FREQUENCY	WARNING (bbl)	ALARM (bbl)
Endicott to PS1		
Last minute	15	40
Last 60 minutes	60	300
Last 24 hours	150	170
Badami to Endicott Tie-In		
Last minute	20	25
Last 60 minutes	n/a	n/a
Last 24 hours	15	16

Results exceeding these tolerances trigger alarms and initiate a response to investigate the cause and shut down production if required.

Mass Pack includes intelligence for smoothing the volume balances for transients. Increases (line packing) in the inlet flow rate can be tuned to show up in the outlet over time. Mass Pack leak detection is based on first principles and is often the most reliable of the three software detection methods

Leak Alarm Response

In the event of a catastrophic rupture of the Endicott/Badami crude oil transmission pipeline, the control operator would immediately detect a total loss of pressure while simultaneously sensing no reduction in flow. Following confirmation, the pipeline would be shut down.

The leak detection system also will alarm for smaller continuous leaks.

If a leak alarm sounds upstream of the Flow Station 2 bypass, the Eastern Offtake Center contacts the Endicott Control Room to determine whether the alarm can be explained. If the alarm is downstream of the Flow Station 2 bypass, Eastern Offtake Center personnel will explain the alarm.

If the alarm can be explained, the leak detection system is reset.

Following an "unexplained" alarm from Endicott and Badami to Pump Station 1, the Eastern Offtake Center contacts Security to request a ground-based visual surveillance of the specific pipeline segment. The Eastern Offtake Center provides Endicott with the results.

If weather or safety prevents ground-based surveillance, then Security requests a Forward Looking Infrared (FLIR) overflight by Shared Services Aviation. If the FLIR overflight reveals an anomaly, the aircraft radios Kuparuk Security which notifies BPXA Security.

BPXA notifies ADEC in writing within 24 hours if a significant change occurs in or is made to the crude oil transmission pipeline leak detection system, and if as a result of the change, the system no longer meets the ADEC performance requirements in 18 AAC 75.055 (18 AAC 75.475). Suspension of the leak detection capability trigger notices to ADEC only if they preclude detection within 24 hours of a leak as large as 1 percent of the annual average daily throughput.

2.5.7 Visual Inspections

Table 2-7 summarizes the visual inspections performed on regulated equipment. Supervisors regularly review the records of daily visual inspections of ADEC-regulated tanks' secondary containments that are required by 18 AAC 75.075.

Flowlines and pipelines are inspected at least monthly, as required by 18 AAC 75.080(n)(1).

More specifically, the following personnel have been identified to support the inspection process:

- Security fills out inspection forms following pipeline inspections. In addition, during routine trips, Security will report oil or gas discharges to the spill reporting telephone line.
- Employees are responsible for conducting visual inspections of their work areas and contacting the operator or Environmental Advisor for clean-up.

Contractors are responsible for visual inspections of work areas and cleaning up spills they may cause. The Environmental Advisor is available to provide support or verification of clean-up efforts.

2.5.8 DOT Pipeline Safe Operations and Emergency Response Equipment Inspection

Inspections of the DOT-regulated sales oil pipeline are conducted as follows:

- Visual inspections at intervals not exceeding three weeks, but at least 26 times per year,
- Mainline and branch valve inspections at intervals not exceeding 7.5 months, but at least two times each year,
- Vertical support member (VSM) inspections annually during the walking-speed survey, and
- A VSM elevation survey at least once every five years.

INSPECTION	RESPONSIBLE POSITION	REGULATING AGENCY	INSPECTION REQUIREMENTS	FREQUENCY REQUIREMENT	REGULATORY CITATION	RECORD KEEPING
Crude Oil Transmission Pipeline	Badami Operations Lead Tech/Shared Services Aviation	ADEC (Badami)	Aerial surveillance for remote pipelines	Weekly, unless precluded by safety or weather conditions	18 AAC 75.055(a)(3)	Visual field inspection form
	Endicott Security	DOT	Surveillance of sales oil pipeline right of way surface conditions	26 times a year, not to exceed 3 weeks between surveillances	49 CFR 195.412(a)	Surveillance form (Badami); DOT Pipeline Inspection Checklist Report (Endicott)

Table 2-7: Visual Surveillance Requirements

Section 4.10 Leak Detection for Crude Oil Transmission Pipelines [18 AC 75.425(e)(4)(A)(iv)]

The selected pipeline leak detection system depends on several technologies including flow measurement, instrumentation, communications, computer hardware and software, and ultimately, experience in operating a system under similar pipeline flow conditions. Because of environmental conditions on the North Slope and the variable flow conditions, it is essential that the selected system have an established track record among North Slope crude oil pipelines. In addition, the chosen system must be redundant, capable of immediately detecting a sudden large volume loss, and capable of detecting a low threshold chronic leak.

Pipeline leak detection BAT employs a mass balance line pack compensation (MBLPC) leak detection system and routine visual surveillance for use in its service. The electronic systems use proprietary software from Ed Farmer and Associates (EFA). The detection systems and upstream processing facility are fine-tuned for optimal leak detection sensitivity.

The MBLPC system, augmented by a program of visual surveillance, is the best available technology for reasons as follows:

- The system is reliable,
- The system has been used in other Arctic applications on similar crude oil production pipelines,
- The system provides state-of-the-art leak detection while minimizing false alarms,
- The system surpasses the regulatory requirements for leak detection thresholds,
- The system provides a low threshold detection capability,
- The system provides a rapid response in detecting large and small leaks,
- The system is commercially available and appropriate for the proposed pipelines, and
- The system provides the best cost-benefit balance.

A BAT review, presented in Table 4-11, demonstrates that the MBLPC leak detection system combined with visual surveillance is BAT for the crude oil transmission pipeline. Due to existing facility design and inherent hydraulic noise, the Pressure Point Analysis (PPA) system may not achieve EFA's claim of one percent sensitivity. The MBLPC system, however, is less affected by hydraulic noise and has proven to detect leaks of less than one percent of the daily throughput.

BAT EVALUATION CRITERIA	EXISTING SYSTEM: MASS BALANCE LINE PACK COMPENSATION	EXISTING METHOD: VISUAL SURVEILLANCE	ALTERNATE METHOD: PRESSURE POINT ANALYSIS (No longer in use)	ALTERNATE METHOD: LINE VOLUME BALANCE SYSTEM	ALTERNATE METHOD: TRANSIENT VOLUME BALANCE SYSTEM
AVAILABILITY: Whether technology is best in use in other similar situations or is available for use by applicant	MBLPC is widely used on crude oil pipelines and is commercially available.	Technology is available, but dated.	Technology has been used on other operating pipelines.	Technology is available and is commonly used on operating pipelines. It takes measured volumes in and out of the pipeline system and compares these to determine if there is a leak.	Technology is available and is used for operating pipelines. A model takes real data from the pipeline and compares actual results against those computed by model. If they do not compare there is an alarm
TRANSFERABILITY: Whether each technology is transferable to applicant's operations	Is in use currently. MBLPC is widely used on oil pipelines. This technology performs best if: 1. Transient flow conditions do not occur frequently. 2. There is no multi-phase flow. 3. There is no slack line flow.	Can be used.	PPA is used on crude oil pipelines. This technology performs best if: 1. Transient flow conditions do not occur frequently. 2. There is no multi-phase flow. 3. There is no slack line flow.	Can be used.	Can be used.
EFFECTIVENESS: Whether there is a reasonable expectation each technology will provide increased spill prevention or other environmental benefits	MBLPC has demonstrated the ability to detect leaks of less than 1% of daily throughput. Performance is dependent upon the location and accuracy of the pipeline flow meters.	An effective means of identifying a leak that can be visually detected. Sometimes leaks occur that are below the threshold limit of the leak detection system and are spotted by visual detection.	It is unlikely that 1% sensitivity can be achieved through PPA, although the system still does have merit, even with less sensitive capabilities. EFA claims PPA and Leak Locator can detect leaks that are as low as or less than 1% of daily throughput. However, PPA and Leak Locator system performance are dependent upon stable flow without hydraulic "noise" and do not provide effective leak detection for the pipeline.	Effectiveness is reduced if pipeline is networked.	A transient model can be effective if field data is accurate, timely, and consistent. The effectiveness of the system suffers when there are changes in the operations or inconsistent data.
COST: The cost to the applicant of achieving BAT, including consideration of that cost relative to the remaining years of service of the technology is use by the applicant.	The system has been purchased and installed.	The cost would be based on trips to cover the pipeline right-of-way. No up-front investment.	The system has been purchased and installed.	Approximate cost is $100,000.	Approximate cost is $200,000.
AGE AND CONDITION: The age and condition of technology in use by the applicant	The system was relatively new when purchased and methods are current.	Method is current.	The system was relatively new when purchased and methods are current	Method is current.	Method is current.
COMPATIBILITY: Whether each technology is compatible with existing operations and technologies in use by the applicant	MBLPC is compatible with the computer and communications of the proposed pipeline systems.	Compatible but small leaks in the below grade sections might go undetected.	PPA and Leak Locator are compatible with the computer and communications on the Badami pipeline system. PPA and Leak Locator are less compatible with the pipeline design and process operations. PPA is less compatible with the facility design and process operations.	Compatible with the computer and communications systems proposed for the pipeline system. Would require significant work if additional segments added.	There may be compatibility problems with the computer systems proposed for the pipeline system because a model would have to run continuously.
FEASIBILITY: The practical feasibility of each technology in terms of engineering and other operational aspects	MBLPC is routinely used on relatively short pipelines	Not feasible to continuously monitor the entire pipeline. Is useful as supplement to an online leak detection system.	PPA is state-of-the-art, proven technology that is ideally suited to steady-state flow conditions. Its sensitivity to pipelines with transient flow conditions is somewhat diminished for Endicott.	Method is feasible and commonly used.	Method is feasible but does provide some risk because of the need to run a model and maintain a model.
ENVIRONMENTAL IMPACTS: Whether other environmental impacts of each technology, such as air, land, water pollution, and energy requirements, offset any anticipated environmental benefits	There are no environmental impacts of MBLPC.	Depending on the mode of transportation it could have affects on the tundra.	No additional environmental impacts.	No impact.	No impact.

Table 4-11: Best Available Technology Analysis – Leak Detection in Crude Oil Pipeline

Appendix III: Expanded references: Included here for convenience only.

A) CFR 195.452(i)(3)

B) US DOT - PHMSA – Integrity Management Program Inspection Protocols

C) Hazardous Liquid Leak Detection – Techniques & Processes, Report No. DTRS56-02-D-70037-01

D) BPXA Integrity Management Plan rev 5, Section 6.04 - Leak Detection

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Parts A & B) CFR 195.452(i)(3) & US DOT IMP Inspection Protocol 6:
The following is a summary of CFR 195.452(i)(3) and Inspection Protocol 6

Verify that the process for evaluating leak detection capability adequately considers the following required factors:

1. Length & size of the pipeline
2. Type of product carried
3. Pipeline proximity to HCA
4. Swiftness of leak detection
5. Location of nearest response personnel
6. Leak history
7. Risk assessment results (→ *to Checklist 1*)

Verify that the process considered

- other relevant factors
- enhancements to existing systems
    i. Consistent application of a risk based decision-making process for leak detection enhancements, as described in Protocol 6.03
- Evaluation of the operational availability and reliability of the leak detection systems, and the operator's process to manage systems failures.

Appendix III Part C - Hazardous Liquid Leak Detection Techniques & Processes - Report N0. DTRS56-020D-70037-01–

- **Section 2.2 Classification of Leak Detection Technologies**
- **Section 2.3 Evaluation of Leak Detection Systems**
- **Section 8 – Enhancements to Protect High Consequence Areas**

Excerpt from the above report are included here for reference.

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Section 2.2 Classification of Leak Detection Technologies

Leak detection technologies can be classified according to the physical principles involved in the leak detection. Using this type of classification, leak detection systems can be divided into the following four groups:

2.2.1 Physical Inspection - This type of leak detection involves either direct or remote visual inspection to detect a leak.

2.2.2 Manual Tabulation - This type of leak detection includes direct monitoring of pipeline flow and/or pressure for evidence of a leak. This may also involve manual calculations to identify lost product.

2.2.3 Discrete Sensor-Based Technologies - Sensor-based technologies rely on the use of an external sensor to detect the escaping hydrocarbon liquid. These systems include, but are not limited to:

- Liquid Sensing
- Vapor Sensing
- Acoustic emissions

2.2.4 Computational Pipeline Monitoring - Computational Pipeline Monitoring (CPM) systems are distinguished from other leak detection systems by the use of an algorithm that uses input from field sensors that monitor the internal pipeline parameters (e.g. pressure, flow, temperature, frictional pressure drop, density, batch interfaces) to determine when a leak has occurred. These systems include, but are not limited to:

- Over and short comparison
- Mass balance with line pack correction:
  - line pack correction based on pressure and temperature sensors
  - line pack correction based on transient flow modeling
- Pattern of discrepancy in pressure/flow between model and measurement
- Rate of pressure/flow change
- Statistical methods that are not model-based
- System identification methods based on digital signal analysis

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Section 2.3 Evaluation of Leak Detection Systems

Each leak detection system is unique based on the pipeline on which it is used. As such, the capabilities of the system and the degree to which it mitigates risk to high consequence areas (HCAs) must be evaluated for each pipeline system. More sophisticated systems will have more unique capabilities. The criteria used to evaluate the capability of an installed leak detection technology may include, but are not limited to, the following:

2.3.1 Leak Size or Leak Flow Rate - What is the minimum leak size that the system is capable of detecting? A leak is detectable only when its' effect rises above uncertainties in the variables being monitored (see Response Time below). The size of a leak is usually expressed as a percentage of the throughput of the pipeline. Leak size is a function of the size and shape of the opening (leak area) and the pipeline pressure. A leak can be either constant in size, such as a pre-existing small leak, or variable over time, such as a sizable leak that diminishes as the pipeline is depressurized.

2.3.2 Response Time - What is the time needed to detect a leak of a given size? Depending on the leak detection methodology used, the response time can vary over a wide range. For algorithms based on volumetric balance, the response time is related to the leak size. This is because of the uncertainties in the variables involved. Uncertainties, or noise in the variables used for leak detection, are always present. A leak can be detected only when its effect, herein called leak signal, is discernable amongst noise. Since noise is random in nature while a leak signal is not, over time, the accumulated noise remains at a noise level while the accumulated leak signal grows in size. Eventually, the accumulated leak signal rises above the noise and becomes detectable in a probabilistic sense (see False Alarms and Misses below). A minimum time period exists for each minimum detectable leak. A curve that relates minimum detectable leak size to response time is a leak threshold curve for this leak detection methodology. Two such leak threshold curves are shown in figure 2-1 to illustrate the general trend. Given an uncertainty level, larger minimum detectable leaks have a shorter response time. A smaller uncertainty in the variable results in a tighter threshold. It takes less time to detect for a given size leak if the uncertainty is reduced. Small leaks with size approaching the combined non-repeatability of instrumentation have a very long response time. Such leaks can only be determined by physical observations. For leak detection methods based on discrepancy patterns generated from a real-time transient flow model, the response time is not a function of leak size. Instead, it is a function of the propagation speed (about 3000 to 4000 ft/s) of a pressure disturbance and the distance between the leak and the nearest pressure or flow sensors.

2.3.3 Leak Location Estimation - Can the system locate a leak and what is the accuracy of the location estimate? The relevance of this criterion is to aid pipeline operator response to a leak in leak mitigation. Location can be estimated based on the time of arrival of a leak disturbance at a pair of sensors. Figure 2-2 indicates a leak occurring at time t0. This leak generates a local pressure drop, which then propagates both upstream and downstream. If this signal is picked up by pressure transducer A at time t1 and by pressure transducer B at time t2, then the leak can be located. This approach requires either a fast data scan rate or the time of arrival at the transducers is registered by data collectors and later transmitted to the control center.

Figure 2-2 Locating a Leak by the Time of Arrival of a Leak Signal (Note: figure not included here)

Alternatively, a leak can be located by the profile of the piezometric head, also known as the hydraulic grade line. Figure 2-3 shows a pipeline with its inlet and outlet pressures held constant. The dotted profile is associated with the steady state flow prior to a leak. The solid profile is the hydraulic grade line after the transients caused by the leak have damped out and a new steady state is established. The leak steepens the upstream hydraulic grade and flattens the downstream hydraulic grade. The effectiveness of this approach relies on multiple pressure sensors along the pipeline so that segments of the hydraulic grade line can be defined after a leak has occurred.

Figure 2-3 Locating a Leak by the Piezometric Head Profile (Note: figure not included here)

2.3.4 Release Volume Estimation - Does the system have the ability to determine the volume of liquid released? Reasonably accurate release volume estimation is possible for CPM methods where a mathematical model for transient flows is used. By using the measured pressure and flow from each end of a pipeline segment, the leak flow rate as a function of time can be calculated. Less accurate release volume can be estimated if a CPM method tracks the mean volume or mass imbalance (linefill change minus the difference between inflow and outflow). When a leak is detected, the volume or mass imbalance prior to and after the leak can be used to estimate the release volume over time.

2.3.5 Detecting Pre-existing Leaks - Does the system have the ability to detect between preexisting leaks, as well as, the onset of a new leak? Some CPM approaches depend on a change in one or several parameters to detect the onset of a leak. Such approaches will not be able to detect a leak (usually small) that is in existence before the CPM is activated.

2.3.6 Detecting a Leak in Shut-in Pipeline Segments - Does the system have the ability to detect the onset of a leak in a shut-in pipeline segment? The detection of a leak under such a situation is a matter of monitoring line-fill change and discerning variations due to environmental temperature variations and/or due to a leak. CPM methods based only on metered inflow/outflow comparison will not be able to detect a leak in a shut-in pipeline segment.

2.3.7 Detecting a Leak in Pipelines in a Slack Condition During Transients - Does the system have the ability to detect a leak in pipelines under a slack condition during transients? Liquid vaporizes when its pressure is sufficiently low. A pipeline is slack if vaporization occurs. A pipeline can be slack under both steady state and transient flow conditions. Leak detection on a slack line under transient conditions is difficult because the uncertainty in line pack change due to vaporization is large.

2.3.8 Rate of False Alarms and Misses - What is the false alarm rate for the system? There are many sources of uncertainty in the data that drive the CPM algorithm. These sources include hydraulic noise, non-repeatability of field sensors, uncertainties introduced by the data collection and communication system (analog-to-digital conversions, data timing), uncertainties in batch positions for product lines, and the state of flow (steady, drifting, or transient). As a result, the output from the algorithm is also uncertain. This uncertainty can be a significant issue facing the CPM technologies.

To illustrate this issue, consider the volume imbalance as the algorithm output. In terms of standardized volumes, subtract the change of line-fill over a time period from the difference between inflow volume and outflow volume over the same period. The result is the volume imbalance. A positive imbalance means a leak. Refer to Figure 2-4 where the estimated imbalance is plotted against the true imbalance. Had the estimations been perfect, all points should fall on the 45-degree (diagonal) line. However, because of uncertainties, the points will be scattered around the diagonal line. Points above the diagonal represent under-estimation of the imbalances, while points below the diagonal represent over-estimated imbalances.

Figure 2-4 False Alarms, misses, and leak thresholds (Note: figure not included here)

The estimated imbalance versus true imbalance plot in Figure 2-4 is divided into four quadrants by the horizontal line labeled "true threshold" and the vertical line B which is the "perfectly estimated threshold." In reality, the true threshold is unknowable and the estimated threshold is determined empirically (by tuning, for example). Scatter of the points near the center of the plot gives rise to false alarms (for those points falling into quadrant IV) and misses (for those points falling into quadrant II). Notice that false alarms and misses occur even when the estimated threshold is perfect. For this reason, and given the fact that variable uncertainties are unavoidable, CPM is not the appropriate technology for detecting very small leaks. However, given the practical limitations of various other technologies, CPMs may be applied as long as the their performance limitations are understood and acceptable to the pipeline operator.

Given the scatter in the estimates, the frequency of false alarms can be reduced by raising the estimated threshold (vertical line C). In so doing, the chances of misses (leaks not detected) increases. Lowering the threshold (vertical line A) reduces the chances of misses at the expense of increasing the frequency of false alarms.

Periods of greater line-fill uncertainty occur when the pipeline is undergoing transients due to planned pipeline operations, such as pump startup and valve swings. To reduce the occurrence of false alarms, the leak threshold may be raised temporarily during such periods. Having the flexibility to raise the leak threshold can be an advantage, provided the operator understands that this is done at the expense of increased chances for misses (see Availability below).

2.3.9 Sensitivity to Flow Conditions - Will operational transients (such as those caused by pump startups or valve swings) degrade the ability to detect a leak? A pipeline seldom operates at a true steady state. This is especially true for long lines with numerous booster pump stations and delivery terminals. The line-fill changes as a result of transients. Volume balance methods that do not compensate for line-fill change accurately will be excessively sensitive to the flow conditions. The uncertainty in line-fill induced by even mild transients can routinely exceed the combined non-repeatability of flow measurements in short time intervals.
Transients generated by pump startups, shutdowns, and valve swings also put extra demands on the data collection system since data polling frequency and timing skew can become issues of concern. Shorter data sampling periods help to discern leaks in such a situation.

2.3.10 Robustness - Will degradation or malfunction of a system component cause catastrophic loss of leak detection ability? This criterion measures how gracefully the leak detection capability degrades when system components malfunction. It also measures a system's ability to function in complex pipeline configurations (see paragraph 2.3.12) when not all the needed information is available. Pipeline operators should be alerted at the first sign of degradation so that restoration efforts can be initiated, and catastrophic loss of leak detection ability can be avoided.

2.3.11 System Self Check - Will the leak detection system have the capability to automatically check and possibly rectify parameters that affect leak detection performance? Will it have the capability to detect and locate non-functional or degrading field sensors and alert pipeline operators?

2.3.12 Ability to Handle Complex Pipeline Configurations - What is the ability of the system to handle complex pipeline configurations as well as complex operations? Complex systems may include multiple injection and delivery points, or multiple modes of operation. These may complicate CPM due to needed model (i.e. algorithm) refinements, increased data requirements, and increased uncertainty when the needed data is not available.

2.3.13 Availability - Is the leak detection algorithm active around the clock? To avoid false alarms, some CPM systems that can not handle transient flow conditions usually increase the detection threshold until the operational transients have passed. Since a leak is equally likely (or even more likely) to occur when a pipeline is experiencing transients, the leak detection function is considered unavailable during periods of raised leak threshold. The percentage of time during which operational transients exist is an important factor in selecting the appropriate CPM method.

2.3.14 Retrofit Feasibility - What is required to install a new leak detection system and/or methodology on an existing pipeline? An upgrade requiring modification to, or addition of, field sensors may be less feasible than one that only requires software modifications. Algorithms that require a prolonged period of on-line parameter tuning are more difficult to retrofit.

2.3.15 Ease of Testing - API 1130 "Computational Pipeline Monitoring" recommends that a leak detection system be tested during commissioning and every 5 years thereafter. As a result, ease of testing to affirm leak detection capability is a relevant criterion. Can the system be tested with pre-existing leak test data, as well as, by actual withdrawal?

2.3.16 Cost - What is the cost of the system including capital and operational expenses, as well as, data and equipment requirements?

2.3.17 Ease of Personnel Training - How are personnel trained on the operation and maintenance of the system? Is the system easy to operate? Complex systems requiring a high level of training may not afford the same level of leak detection capability when the human interface is considered.

2.3.18 Ease of Maintenance - What are the maintenance requirements for the system? Will the system degrade with improper or missed maintenance tasks?

Section 8.0 ENHANCEMENTS TO PROTECT HIGH CONSEQUENCE AREAS

8.1 Introduction

Several options exist for an operator to enhance their leak detection system to protect High Consequence Areas (HCAs). Enhancements can include improvements to enhance the capability and use of existing leak detection methods employed by the operator, as well as, the installation of new systems. Both of these options are discussed in the following section.

8.2 Enhancing Existing Systems

There are a number of actions that an operator can take to enhance the effectiveness of the leak detection systems employed by the operator. These enhancements include physical changes to the detection systems, changes to how the system is operated, and how the operator responds to indication of a leak. Examples of leak detection system enhancements include, but are not limited to, the following:

8.2.1 Improving Measurement Accuracy - Improving the accuracy of the measurement inputs can reduce the detection threshold for a leak detection method. An example of accuracy measurement improvement is where operators use tank gauging to provide a flow measurement input for a volume balance manual over/short or a CPM. The operator could install flow meters to replace the tank gauges for the leak detection input or could install new tank gauges that provide a higher resolution (e.g. replace mechanical tape gauges with radar gauges). (→ checklist 2)

8.2.2 Installation of Additional Sensors - Operators may install additional sensors to enhance leak detection capability. These include sensors that are used for Manual Tabulation (Section 4.0), Discrete Sensor Based Systems (Section 5.0), and Computational Methods (Section 6.0).
Additional sensors could include, but are not limited to:

- Pressure (Manual Tabulation and Computational Methods)
- Temperature (Computational Methods)
- Flow meters (Manual Tabulation and Computational Methods)
- API Gravity (Computational Methods)
- Hydrocarbon detection (Discrete Sensor Based Systems) (→ checklist 2)

8.2.3 Changing Operating Modes - Where the operating mode of the pipeline impacts the performance of the leak detection method employed, the operator can change the operating mode to reduce that impact. For example, a CPM based volume balance method may not be effective during transients. An operator may chose to switch mainline pumps daily to equalize pump wear. Alternating pumps introduces transients into the system that may degrade the ability of the leak detection system until the transient has passed. The operator could change this operation to reduce the number of transients the line is subjected to, thereby increasing the availability of the leak detection system and the protection it provides. (→ checklist 2)

8.2.4 Revising Leak Procedures - Operators may revise or enhance the procedures used by the technicians and controllers in detecting and responding to a leak. Enhancements may include changing action thresholds, increasing technician and controller authority to declare a leak and take appropriate immediate actions, adding job aids such as flowcharts to assist the technician and controller. The use of procedures and job aids can aid the technicians and controllers by working through a logical sequence to verify the existence of a leak, determine the probable location of a leak, and estimate the quantity of the product lost. (→ checklist 2)

8.2.5 Improving Operator Training - Training of the pipeline technicians and controllers in detecting and responding to a leak can enhance the protection of an HCA. The ability of the operator to detect and respond to an indication of a leak is a key element of most leak detection systems. A comprehensive training program can provide operators with the necessary skills to aid the operator in identifying leaks, determining possible leak locations, and taking appropriate actions in response to a leak. Operator training can also be enhanced by the use of simulators and/or emergency drills. Simulators and/or emergency drills allow the operator to practice and reinforce skills and knowledge. Additionally, simulators and/or emergency drills can be used by operators to assess the performance of their technicians and controllers. Performance assessment is required by 49 CFR 195, Subpart G, "Qualification of Pipeline Personnel." (→ checklist 2)

8.2.6 Increasing Frequency of Manual Methods - Operators may increase the frequency of performance of manual leak detection methods. These methods include Visual Inspection (Section 3.0), Manual Over/Short Calculation (Section 4.2), and Pressure Monitoring (Section 4.2). Increasing the frequency of performance for any of these methods would possibly shorten the time that a leak would go undetected and enhance the leak detection ability of the pipeline. (→ checklist 2)

Appendix III Part D - BPXA Integrity Management Plan rev 5

6.04 Leak Detection (LD): Evaluation Factors (49 CFR 195.452(i)(3))

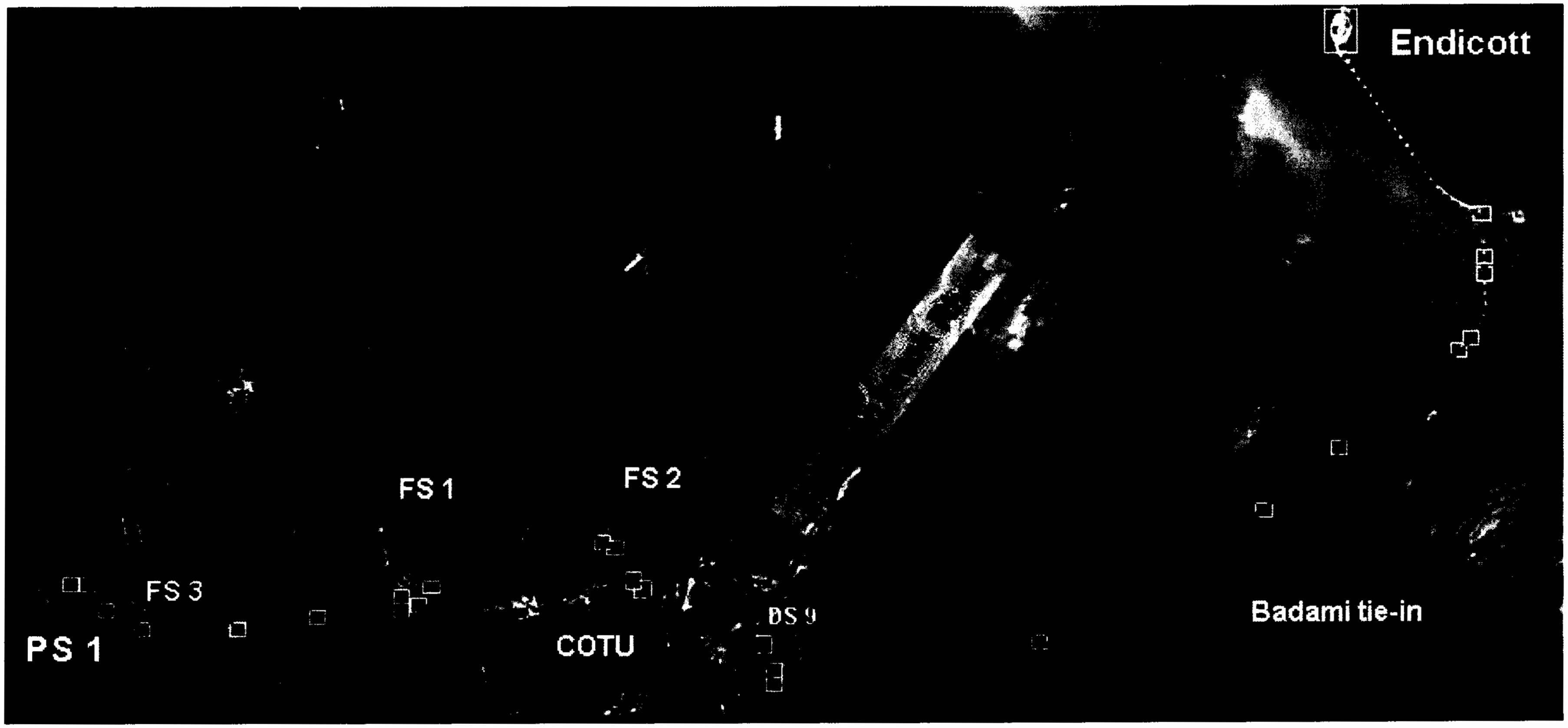
BPXA-operated DOT pipeline systems have leak detection instrumentation that is interconnected to the process facilities via a Supervisory Control and Data Acquisition (SCADA) system and meets the requirements of API 1130. Redundant controls are capable of detecting a sudden large volume loss of product as well as a smaller (pinhole) leak. The Alaska Department of Environmental Conservation's (ADEC) detection requirement is 1.0% of daily throughput. The BPPL NA standard is 5% of average throughput over four hours. By the end of 2Q 2007 Alaskan lines will have their leak detection alarms set to both criteria.

6.05 Leak Detection: Operator Actions/Reactions

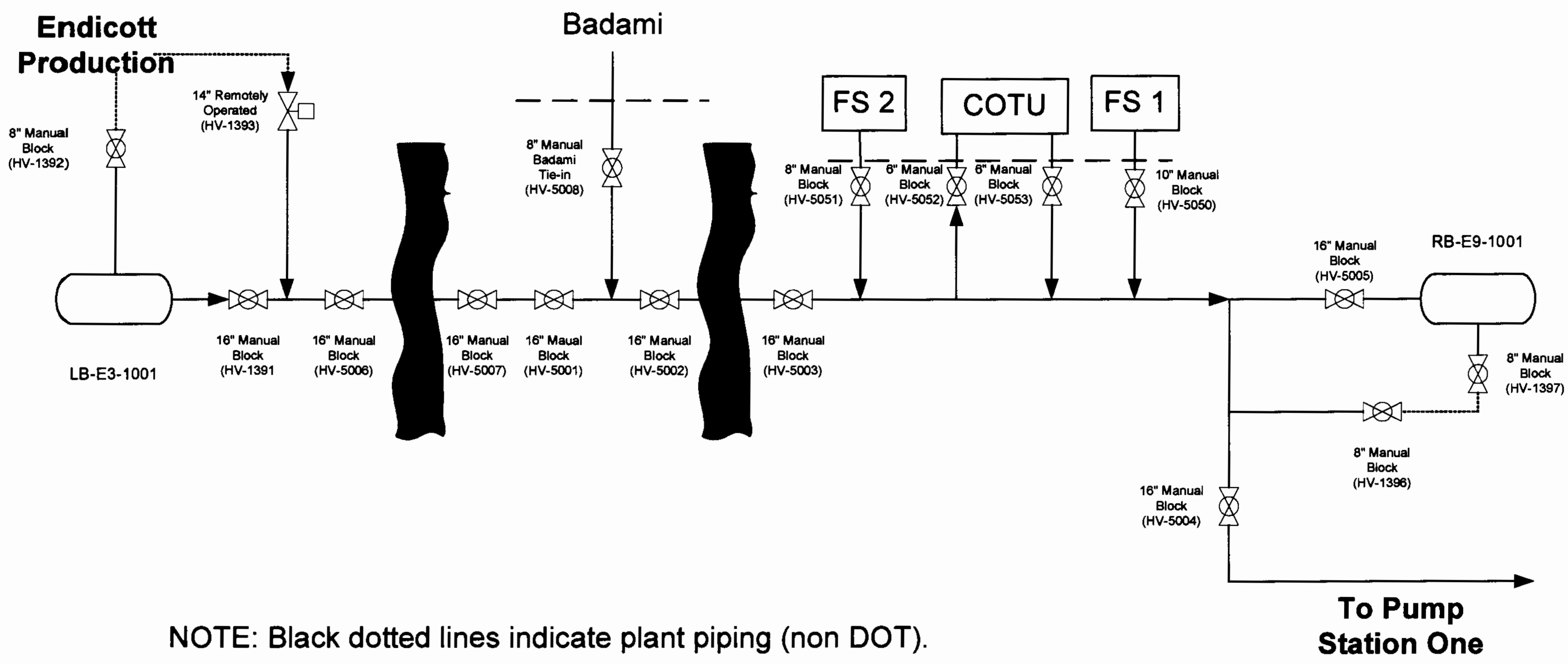
Control Room Operators respond to leak detection indications and also ensure the systems are operating correctly. They are required to initiate reaction measures, shutdown the pipeline if warranted, and manage the system as appropriate. The Control Room Operators evaluate leak detection performance during transient conditions and manage any short-term reduced detection capabilities. Leak detection systems are tested at least annually.

Beginning in 2007, the ***Pipeline Technical Authority*** will review LD criteria and test results with the appropriate Control Center personnel and confirm current stated LD capabilities, including availability and reliability. LD capabilities falling below the comparison criteria shall be identified for possible mitigative actions. Control Center personnel and the ***Pipeline Technical Authority*** shall review mitigation options and develop a multi-year ***LD Mitigation Plan***. The ***Pipeline Technical Authority*** will track the execution of the ***LD Mitigation Plan***. If the current LD system meets CPM criteria, the Control Center will develop the protocol and execute the required performance testing. A ***Leak Detection Checklist*** (*see Risk Assessment Reports for each line*) has been developed for use for this review during the annual Risk Assessment for each pipeline.

Endicott Pipeline Map

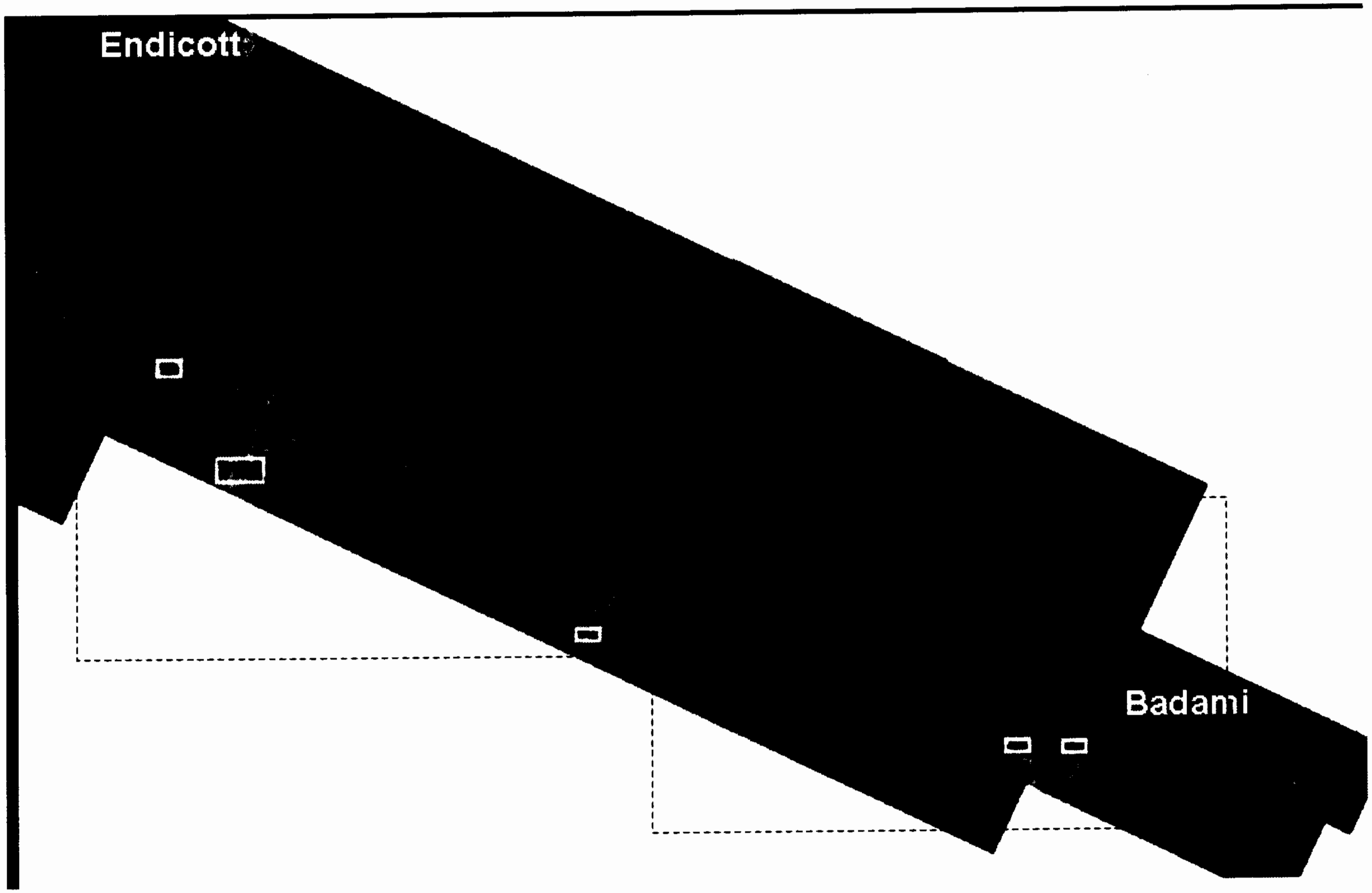


Endicott Boundaries – taken from the Endicott OMER



NOTE: Black dotted lines indicate plant piping (non DOT).

Badami Pipeline Map



Badami Boundaries – taken from the Badami OMER