VALDEZ MARINE TERMINAL NON-TANK CORROSION ABATEMENT STUDY

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TABLE OF CONTENTS

EXECUTIVE SUMMARY 1

DISCUSSION – NON-TANK CORROSION ABATEMENT AT THE *VMT* 3

Review of CMRs 3
Review of Internal Alyeska Documents 3
On-Site Visit and Consultation with Experts 3
Recommendations Developed 3

RECOMMENDATIONS 4

1) Third Party Proof Read 4
2) Track Recommended Actions 4
3) Add Inhibitor Injection Quills 4
4) Regarding the Coupon Watch List 5
5) Do UT Spot Checks for 15% to 19% wall Loss RT Indications 5
6) Use Time-In Service to Estimate Corrosion Rate 5
7) Make Corrosion Field Engineer an Alyeska Employee 6
8) Create Status Table for Close Interval Surveys 6
9) Keep In-Service Drawings of CP Systems Current 6
10) Extend Corrosion Protection to Fire Water Piping 6
11) Correct References to API Standards 7
12) Provide Incentive Program for Corrosion Reporting 7
13) Improve Corrosion Protection for A and B Headers from West Tank Farm 7
14) Monitor Corrosion in BWT DAF Pump Room 7
15) Monitor Over Bends between Headers and Storage Tanks 7
16) Install CP Circuit Control Box at BWT 7
17) Address Corrosion Issues at Berths 4 and 5 8
18) Perform Additional Berth Inspections 8
19) Continue Testing of Industrial Wastewater Sewer System 8

PWSRCAC Objective Number 1 9

"Identify the extent to which non-tank corrosion issues exist at VMT." 9

1) Improve Corrosion Protection for A and B Headers from West Tank Farm 9
2) Firewater Piping 9
3) BWT Piping 10
4) Over Bends Between Crude Oil Storage Tanks 10
5) Industrial Wastewater Sewer 10

PWSRCAC Objective Number 2 11

"Qualitatively assess Alyeska's efforts to address corrosion issues at the VMT."........ 11

1) Impressed Current Systems 11
2) New CP Systems in 2003 11
3) Opportunistic Inspections 12
4) Following-Up on Corrosion Report Recommendations 12
5) Control Box for Partial CP System Deactivation 12
6) Plan Drawing for Protected Piping at VMT Needed 13
7) CP Protection for Firewater System 13
8) Inspection of Firewater Piping 13
9) Firewater Piping on Berths 14
10) Insituform Liner Rings 14
11) Inhibitor Injection Nodes for Berth Piping 14
12) CP Dip Tube Test Stations 14
13) RSPA Waiver 15
14) Weld Pack Corrosion 15
15) PIT Program Piping Inspection 15
16) LRUT Evaluation 16
17) Calculation of Corrosion Rates 16
18) Tank 14 Over Bend 16
19) Over Bend Inspection Program 17
20) BWT Inhibitor Injection and Coupons 17
21) Removal of Corrugated Metal Piping at Over Bends 17
22) Operator Qualifications for DOT Regulated Piping 17
23) Industrial Wastewater Sewer System 17

PWSRCAC Objective Number 3 18

Verify that APSC has procedures in place to identify and to address non-tank corrosion issues." 18

Alyeska's Internal Procedure and Guidance Documents 18
MP-166-3.01, "Corrosion Inhibitors, Pump Stations and VMT" 18
MP-166-3.02, "Internal Corrosion Coupon Program" 19
MP-166-3.03, "Facility Corrosion Integrity Monitoring" 20
MP-166-3.05, "Cathodic Protection Monitoring Data Analysis" 21
MP-166-3.07, "Bi-monthly Inspection – Impressed Current Cathodic Protection Services" 22
MP-166-3.09, "Valdez Marine Terminal Cathodic Protection Systems" 22
Alyeska Master Specification B-511, Pump Station and Terminal Pipe Investigation 22
Alyeska Master Specification B-512, Pipeline Corrosion Evaluation Procedures 23
Alyeska Master Specification B-513, Terminal Vapor Recovery System Pipe Investigation Specification 23
MR-48, Trans Alaska Pipeline Maintenance and Repair Manual 23
SUR-10, Surveillance/Repair Procedure for Belowground Piping or Equipment Integrity Management 24
AMS-004-01, TAPS Engineering Guidance Manual, TAPS Engineering Guidance Manual 24
AMS-019, Assessment Process 24
AMS-020, Internal Audit Process 24

PWSRCAC Objective Number 4 25

"Verify that maintenance schedules are sufficiently frequent to address the recurring non-tank corrosion issues." 25

API 570 25

PWSRCAC Objective Number 5 27

"Verify that appropriate standards regarding non-tank corrosion issues are in use at VMT and that these standards drive appropriate maintenance and inspection schedules." 27

NACE RP0775-99, "Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations." 27
NACE RP0169-02," Control of External Corrosion on Underground or Submerged Metallic Piping Systems." 27
API 570, Piping Inspection Code 28
ASME B-31.3, Chemical Plant and Petroleum Refinery Process Piping Code 29
ASME B-31G, Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B-31 Code for Pressure Piping 29
49 CFR 192, Transportation of Hazardous Liquids by Pipeline 29
49 CFR 195, Transportation of Hazardous Liquids by Pipeline 30
18 AAC 75.080, Facility Piping Requirements for Oil Terminal, Crude Oil Transmission Pipeline, Exploration, and Production Facilities 31

PWSRCAC Objective Number 6 32

"Verify that permitted (either by standard or custom) levels of non-tank corrosion are acceptable and that inspection schedules are sufficiently frequent and thorough such that all existing corrosion will be identified and will not exceed the permitted levels." 32

APPENDIX 1 LIST OF ACRONYMS/NAMES 33

APPENDIX 2 DEFINITIONS 35

APPENDIX 3 REFERENCES 37

Alyeska Documents 37
National Association of Corrosion Engineers (NACE) Documents 38
American Petroleum Institute (API) Documents 38
American Society of Mechanical Engineers (ASME) Documents 38
U.S. Department of Transportation (DOT) Documents 38
State of Alaska Administrative Code Documents 38

APPENDIX 4 Evaluation of Marine Structures 39

EXECUTIVE SUMMARY

In the spring of 2004, Coffman Engineers, Inc. *(CEI)* was commissioned by the Prince William Sound Regional Citizen's Advisory Council *(PWSRCAC)* to investigate the non-tank corrosion issues at the Valdez Marine Terminal *(VMT)*.

CEI was given six goals and objectives to establish scope and direction for the study.

1) Identify the extent to which non-tank corrosion issues exist at *VMT*.

2) Qualitatively assess Alyeska's efforts to address corrosion issues at the *VMT*.

3) Verify that Alyeska Pipeline Service Company *(APSC)* has procedures in place to identify and to address non-tank corrosion issues.

4) Verify that maintenance schedules are sufficiently frequent to address the recurring non-tank corrosion issues.

5) Verify that appropriate standards regarding non-tank corrosion issues are in use at *VMT* and that these standards drive appropriate maintenance and inspection schedules.

6) Verify that permitted (either by standard or custom) levels of non-tank corrosion are acceptable and that inspection schedules are sufficiently frequent and thorough such that all existing corrosion will be identified and will not exceed the permitted levels.

It was found that some non-tank corrosion issues do exist at the *VMT*, but they have either been repaired and are under monitoring, or they are being monitored and are not currently at the point where repair is required. As pertains to regulatory issues, the inspection and corrosion mitigation program meets or exceeds regulatory requirements, with one exception. The required (by 49 CFR 195.589) current site plan of cathodic protection (CP) systems showing anodes, rectifiers, protected structures, and neighboring bonded structures is not to scale or of sufficient detail to act as a project design aid during demolition/construction of existing/new structures and CP systems. See item #9 in the Recommendations section for further detail.

In some instances, Alyeska has taken the initiative and acted beyond recommendations in order to mitigate a situation. Objective 2 contains many items where a good effort has been noted.

Part of the *VMT* corrosion inspection plan includes cathodic protection evaluation of the berths, Crowley tug dock, and small boat harbor at the VMT. Periodically a visual, diver assisted, examination of the main loading docks (MLD's), berthing dolphins (BD's), and mooring dolphins (MD's) of berths 4 and 5 are performed. The diver assisted examinations consist of visual assessment, ultrasonic testing (UT) thickness spot checks, and UT checking for flooded member detection. If suspect welds are noted, follow-up is done with magnetic particle examination and weld photography. These examinations are not driven by regulation. Maintaining the structural integrity of the berths and docks is driven by good engineering and business practice. Since these areas pose no direct threat in the form of a spill, and the examination results were generally satisfactory, they were not considered to be of major concern in the scope of this evaluation. A summation of their examinations is presented in the appendices.

With the exception of the aforementioned site plan, the data reviewed indicates the *VMT* corrosion mitigation plan is conscientious, conforms to regulation, and follows good engineering practice.

The format of this report follows the objectives and each item is cross referenced in bold if it appears in a different section. The in depth reader should begin with the Recommendations, which precede, and are referenced to, Objectives 1 and 2. The discussion of Objective 1 addresses existing issues of active corrosion, as opposed to peripheral issues such as improvements on reporting. The discussion of Objective 2 is an assessment of issues and efforts, and includes efforts where recognition is deserved, as well as instances where improvement can be made. The discussion of Objectives 3 and 4 cover Alyeska's procedures and maintenance schedules, and the discussion of Objective 5 goes over the codes and recommended practices that drive them. The discussion of Objective 6 is a general summation of the previous 5 objectives.

DISCUSSION – NON-TANK CORROSION ABATEMENT AT THE *VMT*

The *VMT* was designed in the 1970s for a 30 year operational life. Various upgrades have been performed in the 1980s and 1990s, but the components and subsystems are subject to wear due to mechanical action and corrosion from handling inherently corrosive fluids. Alyeska maintains a staff of engineers to address mechanical integrity and corrosion issues. It also spends a significant portion of its budget to address corrosion issues. *PWSRCAC* wished to verify that all issues have been identified and addressed, and that maintenance schedules are reasonable to ensure the best possible care for the safety and operation of the *VMT*.

Review of CMRs

CEI's initial approach to the task was a review of the 2002 and 2003 *VMT* Corrosion Monitoring Annual Reports, supplied by Alyeska. The reports cover the Pipe Integrity Testing (PIT) program, Close Interval Survey (CIS), test station monitoring, rectifier monitoring, and internal corrosion program. The reports were examined for specific corrosion issues in each of their four reporting areas, for thoroughness, and for continuity of program.

Review of Internal Alyeska Documents

The second step was to review Alyeska's applicable procedures, specifications, drawings, manuals, and processes, also supplied by Alyeska. Alyeska's internal documents were compared to the applicable industry codes and recommended practices for engineering thoroughness and adherence to accepted industry standards. Alyeska's internal documents were then compared to the applicable regulatory requirements for compliance. *CEI* also reviewed Alyeska's internal audit and assessment procedures which provide Alyeska a reasonable assurance that it's engineering staff are adhering to good engineering standards, complying with regulations, and generally "doing the right thing".

On-Site Visit and Consultation with Experts

A list of questions were developed as a result of the above, and two days were spent in Valdez with Alyeska hosting a question and answer session. The program subject matter experts were present, and access was provided to the terminal, and to the corrosion data for verifications, if required. Alyeska was open and accommodating and their assistance is acknowledged here.

Recommendations Developed

The recommendations below predominately are suggested improvements on reporting procedures and methods, emplacement of new inhibitor/coupon fittings, and urging to follow through with some recommendations from the annual reports. Item #9 calls for a plan drawing to comply with a regulatory requirement.

RECOMMENDATIONS

The following recommendations are offered as improvements to the *VMT* corrosion abatement program. Where applicable, the recommendation is **cross referenced in bold** to another mention of the specific topic in this report.

1) *Third Party Proof Read*: The annual report is usually completed at year's end, under a deadline. Even the greatest of care can still result in oversights or accounting errors being made. For this study, two annual regulatory reports, prepared at year's end, were examined. Although care went into preparation of the report, minor errors associated with oversights, inconsistency, and continuity with previous reports were observed. A third party proof read would likely have identified the majority of such errors. After completion of the annual report for the regulators, consider having a knowledgeable third party proof read the document for contradictions, technical correctness, oversights, placement of data in the correct sections, and continuity with the previous year's report.

   (See Recommendations, Items #2, #4, #8, and #11)

2) *Track Recommended Actions*: All recommendations from the previous year should be tracked in the following year's report. Action, non-action, results (successful or not), follow-through, and extra initiative actions should be reported as is appropriate.

   Note: At the time of publication of this report, APSC has published MP-166-1.00. This IM Programs Process provides for engineering and maintenance recommendations from all TAPS projects and activities to be entered into a Management Actions and Commitments (MAC) database. The MAC database allows IM engineers to prioritize programs and develop long range plans. Needed actions are to be prioritized and sorted based on due dates.

   It is recommended that VMT corrosion recommendations from the MAC database be published and tracked in the annual corrosion report. A copy of MP-166-1.00 was not received until the day of publication of this report and so a detailed synopsis is not included in this report

   (See Objective 2, Item #4)

3) *Add Inhibitor Injection Quills*: The nearest coupon monitoring locations to the berth loading arms are upstream of the last expansion loops. Direct assessment in the form of the PIT program RT/UT is used to monitor the berth loading arms. Consider placing some inhibitor injection quills, along with some monitoring coupons, at the loading piping for dosing the stagnant oil between tanker loading operations.

   (See Objective 2, Item #11)

4) *Regarding the Coupon Watch List*

   a. The Ballast Water Treatment (BWT) coupons 51-01A and 51-02A were not reported on the 2002 watch list. The 2003 report (page 23) reports them consistently as "severe" since the spring of 2002, with no change to the fall of 2003. Any coupon greater than "low" is supposed to be placed on the watch list. Verbal inquiry revealed that these two coupons should have been on the 2002 watch list, but were not included due to an oversight. These coupons are now on the watch list and the inhibitor injection rate will be adjusted appropriately after installation of a new injection location in 2004.

   b. The West Tank Farm coupons 55-16A & 55-16C were on the 2002 watch list (See the 2002 report, page 3, and this report, Objective 3, MP-166-3.02) as "moderate" and "high", respectively. No mention of them is made in the 2003 report, and no mention of dosage increase at their injection points is made either. Verbal inquiry revealed their next two pulls did indicate "low". It would be a good follow through to mention in the 2003 report that their next two pulls indicated a "low" average corrosion rate, and mention whether or not that was accompanied by an increase in inhibitor dosage.

   (See Objective 3, section heading MP-166-3.02)

5) *Do UT Spot Checks for 15% to 19% wall Loss RT Indications*: UT follow-up is performed in the PIT program where RT densitometry indicates 20% wall loss. RT is a qualitative screening method and inspection history at the VMT has shown that a 20% wall loss indication can prove up with UT to be as little as 2.8% (conservative error) to as much as 24.5% (extreme error). Published industry literature reviewed to date does not discuss this inaccuracy but it may be prudent to consider making UT spot checks where RT indicates 15 to 19 percent wall loss.

   (See Objective 2, Item #15)

6) *Use Time-In Service to Estimate Corrosion Rate*: Alyeska's present practice in the PIT program is to not calculate a corrosion rate at a particular site until the second investigation is performed at the site. Such practice may prevent early identification of a corrosion issue until it has become a more serious problem. In those instances when the extent of wall loss has been determined (using UT) at an initial baseline investigation, consider using the time in service to determine the corrosion rate, even though this assumes corrosion began at day one. Until better information is known regarding corrosion rate at a site, such information would permit the development of more discerning inspection schedules.

   (See Objective 2, Item #17)

7) *Make Corrosion Field Engineer an Alyeska Employee*: The duties of the *VMT* Corrosion Field Engineer (CFE) include flange examinations, maintenance of rectifier status information, opportunistic pipe inspections, record keeping, advising the Projects Group regarding required system shut-offs and the presence of anode ground beds, and management of day-to-day corrosion questions as they arise. The CFE also trouble shoots and fine tunes the terminal's interacting CP systems as required. The CFE is generally the first resource called upon when a *VMT* CP question arises. Additionally, the CFE provides assistance and support to the Internal Corrosion and *VMT* PIT Program single point of contact (SPOC)s. Alyeska has made a considerable investment in the encyclopedic knowledge of *VMT* CP systems possessed by its present CFE. Currently, the present position of *VMT* CFE is filled by a contractor whose employment status is subject to the uncertainties of repeated contract negotiations. Consideration should be given to making the CFE position a direct-hire.

(See Objective 1, Item #2, Objective 2, Items #1, #3, and #6)

8) *Create Status Table for Close Interval Surveys*: The percentage of buried piping in each category that was surveyed for cathodic protection levels (close interval surveyed, or CIS'd) should be noted in a table (example: FW – 20%, Buried Crude – 100%, etc.). The percentage not meeting criteria for protection in each category should then be noted (example: 18% of the surveyed FW, 2% of the surveyed Buried Crude, etc.). This will give a succinct representation of the CIS results.

9) *Keep In-Service Drawings of CP Systems Current*: As strategic reconfiguration (SR) unfolds, and piping systems are demolished/constructed and impressed current CP systems are abandoned/installed, scrupulous attention should be paid to the effect of same on the CP current distribution and piping protection levels. The VMT plan drawing showing CP system locations should be surveyed and drawn to scale. It is presently not detailed enough to provide adequate information for the design of demolition/construction work packages, or to lead a new contractor to the location of an anode string, structure bond, control rheostat, etc. Such detail is called for in the current plan map required by 49 CFR 195.589. It is anticipated that one drawing will not be sufficient to accurately document the cathodic protection systems and components and that several drawings will be required including one line diagrams, system schematics and accurate as-built drawings of all buried components. To date, these are inadequate.

(See Objective 2, Item #6)

10) *Extend Corrosion Protection to Fire Water Piping*: The buried/aboveground Fire Water (FW) system is not required to be CIS'd or thickness tested. It is, as a matter of good engineering practice, CIS'd at the rate of 20% per year and thickness tested at intervals governed by calculated half-lives. If the areas of low potentials persist after SR, it is recommended that dedicated CP systems be installed to mitigate the areas of low protective potentials. All new piping installed by the SR should have adequate corrosion control measures implemented.

(See Objective 1, Item #2, and Objective 2, Item #7)

11) *Correct References to API Standards*: MP-166-3.03 (Alyeska's Maintenance Procedure Manual) references API570, sec. 4.1 for piping classification. The correct reference is API570, sec. 6.2. This reference should be corrected.

12) *Provide Incentive Program for Corrosion Reporting*: A 69% wall loss in a steam condensate line (not considered part of the Vapor Recovery Lines) in the power/vapor facility was discovered due to an asset request for inspection. The pipe wall was found to be more than adequate to contain the pressure and the area was remediated with a high temperature coating. The reporting technician was attentive enough to notice a potential problem area of external corrosion. The APSC Code of Conduct compels employees and contractors to report on observed integrity issues. An existing employee recognition program allows any individual to nominate any other individual for attentiveness or exemplary work, with the possibility of financial or material rewards. Continue to remind employees and contractors of this recognition system.

13) *Improve Corrosion Protection for A and B Headers from West Tank Farm*: The area of low cathodic protection levels on the A and B headers on the hill from West Tank Farm down to West Metering should be noted as a concern in the annual reports so it isn't overlooked while SR is in progress. Since the levels of cathodic protection are adequate at the top and bottom of the hill, and a recent opportunistic inspection during an excavation on the hill revealed no unacceptable conditions, no immediate action may be required at this time. The situation should be revisited after the SR piping changes and resultant CP current distribution changes.

    (See Objective 1, Item #1)

14) *Monitor Corrosion in BWT DAF Pump Room*: Continue to monitor the grid locations in the BWT DAF pump room. Ensure that any loss of containment will drain into the Industrial Wastewater System (IWWS) for processing.

    (See Objective 1, Item #3)

15) *Monitor Over Bends between Headers and Storage Tanks*: Continue to monitor the over bends between the crude storage tanks and headers in the Oil Movements and Storage (OM&S).

    (See Objective 1, Item #4)

16) *Install CP Circuit Control Box at BWT*: Install the recommended CP circuit control box for the 58-R-58-2 CP rectifier along Port Valdez Drive in front of BWT. This will allow isolation and separate control of the various CP systems on this rectifier. A control box is needed to allow partial system deactivations rather than a wholesale shutoff during projects that affect only one small part of the system. This has been recommended in the 2002 and 2003 reports, and has been slated as a 2005 work item.

    (See Objective 2, Item #5)

17) *Address Corrosion Issues at Berths 4 and 5*: Replace the corroded bolts securing the fenders at berths 4 and 5. It is possible the fenders could come loose and foul or damage the oil booms. Consider removal of the horizontal chains at these berths. Some are damaged, and all are corroded and per the 2003 report, serve no known purpose. These recommendations were made in the 2003 report. Examine all other fenders for similar problems and make replacements if necessary.

(See Appendix 4, Evaluation of Marine Structures)

18) *Perform Additional Berth Inspections*: Perform periodic diver assisted visual inspection of all marine anode connections and mounting hardware to ensure continued sufficient levels of cathodic protection at the berths, small boat harbor, and Crowley tug dock.

(See Appendix 4, Evaluation of Marine Structures)

19) *Continue Testing of Industrial Wastewater Sewer System*: Continue hydrostatic and pneumatic testing of the Industrial Wastewater System (IWWS) per the present schedule, and make repairs as required.

(See Objective #1, Item #5, and Objective #2, Item #23)

PWSRCAC OBJECTIVE NUMBER 1

"Identify the extent to which non-tank corrosion issues exist at VMT."

The following potential and existing issues are identified, and are **cross referenced in bold** to another mention of the specific topic in this report.

1) *Improve Corrosion Protection for A and B Headers from West Tank Farm*: The A and B headers on the hill from West Tank Farm down to West Metering have CP coverage ending at the top, from nearby cathodic protection deep anode groundbeds, and beginning again at the bottom, from Anodeflex anode systems. CP potentials on the slope of the hill itself have historically been low, and of concern. A recent dig on the adjacent FW line exposed part of the A and B header and visual inspection of the exposed crude line revealed no unacceptable conditions. Two dip tube cathodic protection test stations were installed at the dig site on the hill for future CP measurements. Additionally, a recent amperage requirement test demonstrated that protective potentials for the entire line segment can be improved with additional CP, and a preliminary CP design has been completed. System installation has been recommended for 2006, but is pending since there is the possibility that these headers may be demolished under SR.

   (See Recommendations, Item #13)

2) *Firewater Piping*: There are no dedicated CP systems for the FW piping, and none are required by API570 guidelines, state, or federal regulations. However, the FW piping is electrically continuous with the other VMT piping and some protection is afforded from the other CP systems. One third of the measurements obtained at the fire hydrants in 2002 do not meet criteria (as established by NACE standard RP0169-02) for cathodic protection and the 2003 report indicates that 18% of the buried FW piping close interval surveyed in 2003 did not meet criteria for cathodic protection.

   No dedicated systems are presently planned for the FW piping since SR will likely alter much of the current distribution on the entire *VMT* through removal of existing and installation of new piping, FW and other piping included. SR changes in the FW system presently under consideration include conversion of the system from salt to fresh water, and demolition/construction of old/new FW piping. As the terminal-wide piping arrangement changes, the distribution of CP current will change, and further evaluations will have to be made upon completion of the piping changes. Although not required to monitor the FW system CP, Alyeska does recognize the importance of a functioning fire suppression system. Presently, the terminal CFE scrutinizes CP potential data to adjust rectifier outputs to optimize overall protection without localized overprotection.

   (See Recommendations, Item #10, and Objective 2, Item #7)

3) *BWT Piping*: The 2003 report identifies the worst case corrosion as a through-hole (resulting in a contained spill) and 69% wall loss on the 24” BWT tank piping tees in the DAF pump room. This specific area was not previously inspected as there was no historical or operational justification to inspect these types of design locations where a doubler or saddle exists. Subsequent to the leak, Alyeska began inspecting similar piping configurations on similar pressure legs and reported the findings in the 2003 annual report.

Due to piping configurations, the magnitude of work involved with completely replacing the compromised tees, and tees of similar service, at this location would warrant development of a complete engineering project. A patch has been welded over the area containing the 69% wall loss and the through-hole, per API570 repair guidelines for existing piping. Continued monitoring of these tees will take place by the PIT Program with intervals based on half lives calculated from initial and continued findings.

As SR unfolds, BWT may become obsolete, but it will be required until 2015 when the last remaining single hulled tanker will be decommissioned as required by OPA-90. The interim action of patching and ongoing monitoring should provide a sufficient level of containment and safety. *There are many PIT Program existing grids in the DAF room piping, and 3 more were added to the pressure leg where the through-hole and 69% wall loss were discovered.* (A “grid” is a matrix of one-inch squares painted onto the inspection site. During inspection, the UT technician “scrubs” each square ultrasonically and records the minimum RWT). It is reasonable to continue to monitor the grids in the DAF pump room and make repairs as required.

(See Recommendations, Item #14)

4) *Over Bends Between Crude Oil Storage Tanks*: Active corrosion has also been identified at the over bends (a pipe bend similar to a vertical horseshoe) between the crude storage tanks and headers in the OM&S. The over bend from the B header to Tank 14 was found to have a recurring corrosion rate of 10 mpy (a rate of 5 mpy is considered high). These over bends and similar pressure legs are being monitored as part of the PIT Program. Wall thicknesses are inspected at RSTRENG half-lives (not to exceed API570 recommended intervals for the piping class).

(See Recommendations, Item #15)

5) *Industrial Wastewater Sewer*: The IWWS has no CP system and it is not practical to install one because the piping is mechanically jointed cast iron. Installing CP on the piping would entail digging up the entire system and electrically bonding every joint for continuity throughout the entire system. The system is currently tested hydrostatically and pneumatically. The testing program covers the whole system every 5 years, and there have been a few test failures every year since 2002. The sections are usually repaired the following summer.

(See Recommendations, Item #19, and Objective #2, Item #23)

PWSRCAC OBJECTIVE NUMBER 2

"Qualitatively assess Alyeska's efforts to address corrosion issues at the VMT."

The following list of Alyeska's efforts to address corrosion issues has been culled from the annual reports reviewed, and interviews with the SPOCs. Generally speaking, the efforts are adequate. Specifically, where there are opportunities for improvements on an effort, these have been **referenced in bold** to the corresponding recommendation. Efforts that have little or no recommended improvements are also **recognized in bold as "good engineering practice"**.

1) *Impressed Current Systems*: Impressed current CP systems can cause sparking or problems with pipe welding if left on during a project. Rectifiers are manually deactivated for system repairs or projects safety lockout/tagout (where electrical circuit breakers or piping valves are physically locked in the off or closed position). Generally the units are re-energized at the end of the project, but occasionally one is forgotten during project close-out, and left out of service.

   Shutting off a rectifier causes the pipe to lose cathodic protection polarization, but on a well protected structure, the progress of corrosion is not usually a concern for a month or so. The *VMT* CFE currently takes it upon himself to keep track of rectifier shut-offs. The CFE also advises asset managers on which systems need to be shut off for a given project, and notifies the Fairbanks IM engineer of which units have been taken out of service.

   A measure of redundancy is provided by a Fairbanks data analyst who reviews the bi-monthly rectifier readings. The analyst is tasked to alert the Alyeska IM engineer when a system is logged as "off" for two readings in a row (a four month span). This redundancy also spots units that have failed inadvertently due to a blown fuse, and would not otherwise be noticed by the CFE.

   A third redundancy will be provided by the Bailey (facility control system) monitoring plan, a computerized remote monitoring system, which is scheduled for completion in 2005. The Bailey monitoring plan will alert OCC when a rectifier is off so that it can be investigated immediately, as well as allowing the rectifier outputs to be monitored remotely, thus eliminating the need for a technician to manually perform the bimonthly checks.

   (Good Engineering Practice)

2) *New CP Systems in 2003*: Two new CP systems were added in 2003; Tank 93 bottom (outside the scope of this study) and Small Boat Harbor diesel fuel CP system.

   (Good Engineering Practice)

3) *Opportunistic Inspections*: Crude piping is always examined when exposed and corrective action taken if required, per directives in MP-166-3.03. Per SUR-10, “opportunistic inspections” are always performed when a pipe is exposed due to removal of insulation or excavation. SOP at the *VMT* is to have a CFE present at excavations to make and record a visual evaluation of exposed piping, conduit, and metal structure. If dents, dings, or other irregularities are observed then further investigation and repair is performed as warranted.

   (Good Engineering Practice)

4) *Following-Up on Corrosion Report Recommendations*: Previous year’s recommendations are sometimes, but not always, followed through in the next year. Occasionally the follow-through exceeds the recommendations. Some examples include:
   a. The 2002 report recommended installation of internal coupons into selected deadlegs, and in the vault areas around the headers of the suction and discharge pressure relief lines. The 2003 report confirms installation of coupons and inhibitor injection quills at the latter, but no mention is made of installations on the former.
   b. The 2002 report recommended continuing to evaluate the low potentials in the 36” crude relief line near East Metering. The 2003 report reports that Anodeflex upgrades were installed along this section of line, exceeding the recommendations.
   c. The 2002 report recommended installation of an impressed current CP system to protect the 48” A and B headers between Tanks 1 and 6. An Anodeflex system was installed in this area in 2003, per the recommendations.
   d. Recommendations were made in the 2002 report to monitor potentials at the:
      - CMP removal location at the Tanks 9&10 headers.
      - New CP system location at the Dayville Creek pipe crossing.
      - Recovered crude line tie-in to the A and B headers.

      The updated plan drawing indicates adequate CP in the above areas. However it is desirable that action or non-action of all recommendations from the previous year be reported in the next years’ report.
   e. Recommendations were made to add new PIT program inspection sites in the fuel piping systems for 2003. The 2003 report discusses three separate locations that were targeted in 2003 for PIT inspection. It doesn’t say if they are new sites or not.
   f. The 2002 PIT report recommends development of a new plan for investigation of piping under insulation. The 2003 report describes the new plan of using RT to screen for areas of >20% wall loss prior to UT testing. It should be mentioned that this is the new plan and so noted that the recommendation was followed through.

   (Good Engineering Practice, and also See Recommendations, Item #2)

5) *Control Box for Partial CP System Deactivation*: The 2002 and 2003 reports recommended a CP circuit control box for the 58-R-58-2CP rectifier (on Port Valdez Drive in front of BWT) to isolate and control the various CP systems on this rectifier. A control box was needed to allow partial system deactivations rather than a complete shutoff during a project that affected only one small part of the system. A similar control box was installed in 2003 on the system at Four Corners intersection and allows work to be done on piping north of the intersection without having to deactivate the anodes for piping on the south side of the intersection. The 58-R-58-2CP circuit control box has been slated as a 2005 work item.

   (See Recommendations, Item #16)

6) *Plan Drawing for Protected Piping at VMT Needed*: Alyeska maintains an annually updated plan drawing showing the CP rectifiers and protected piping at the *VMT*. Areas of below criteria CP potentials are indicated. However, the drawing is not to scale and does not show in detail all the Anodeflex runs with their associated cabling. In the event that any demolition or reinstallation of CP systems is required for strategic reconfiguration, the existing drawing will not be adequate for accurate project planning. Locating of cable runs and which rheostats control which systems will be dependent on the historical memory of the present CFE. Many of the existing CP systems were surveyed in for project as-builts, but they were archived by project number, so all-inclusive to-scale plan drawings, one line diagrams and detailed schematics of the *VMT* CP systems are not available. It is recommended that to-scale plan drawings and schematics be created showing anode bed, cabling, junction box, rheostat, control box, and rectifier locations for all the *VMT* CP systems. The rheostat and control box details should indicate which rheostat/control box controls which anodes. The drawings should also show the cathodically protected piping and neighboring structures (such as FW piping) bonded into the CP system. These drawings are required by 49 CFR 195.589.

(See Recommendations, Item #9)

7) *CP Protection for Firewater System*: One third of the pipe-to-soil potentials obtained at the fire hydrants in 2002 do not meet criteria for cathodic protection (per NACE RP0169-02) and the 2003 report indicates that 18% of the buried FW piping CIS'd in 2003 did not meet criteria for cathodic protection. The 2002 report mentions no corresponding figure for FW CIS. The FW lines are not required to be inspected per API570 or MP-166-3.03 guidelines, state, or federal regulations. However, 49 CFR 195.430 says that each operator shall maintain adequate firefighting equipment "in proper operating condition at all times".

About two thirds of the buried FW system was subjected to close interval survey from 2001 to 2003, and the CIS for other one third is planned for 2004 and 2005. Areas of low potential are targeted for remediation and opportunistic visual assessments are performed during digs as pipe is exposed.

When SR comes into play with terminal-wide piping arrangement changes, and addition or removal of CP systems, the distribution of CP current will change and the protection levels of the FW piping, and all buried piping, will need to be verified/reassessed.

(See Recommendations, Item #10, and Objective 1, Item #2)

8) *Inspection of Firewater Piping*: Alyeska has just completed a multi-year A/G and B/G examination of the buried FW system which included internal inspection of the large bore piping, as well as lining and re-coating. The 24" and larger FW lines have been relined using Insituform. The smaller bore pipe is cement lined. FW piping is replaced as failures are noted, or at opportunistic digs.

(Good Engineering Practice)

9) *Firewater Piping on Berths*: The marine facility FW lines are all exposed pipe and are on the regular PIT program. The maximum re-inspection interval provided by API570 is 10 years, however these cement-lined pipes contain stagnant seawater, and any breach in the mortar lining tends not to support much corrosion on the steel due to the low availability of oxygen. A through-hole in these lines could result in failure to adequately pressurize and deliver firewater in the event of an incident, but a corrosion related spill would pose little threat since the effluent would be seawater. Since inspection is not required for these lines, the PIT program re-inspects these lines based on RSTRENG half-lives only. RSTRENG is an API recognized method for evaluating remaining pipe strength and estimating remaining life. Present PIT data RSTRENG half-lives indicate that no inspections are required until 2015. Given the above considerations, this is a good engineering and business practice.

(Good Engineering Practice)

10) *Insituform Liner Rings*: A one-inch diameter through hole, due to internal corrosion, was found on the BWT large bore piping in 2000 where the Insituform lining was found detached from the interior of the pipe. The through hole on the buried section was patched and then re-lined. Core samples were collected in the surrounding soils, and no contamination was detected. The BWT piping has been relined with Insituform lining. This is the same lining that originally was in the BWT piping and experienced failures stemming from problems at the liner rings at the flange connections. The new liner rings are titanium and are much improved over the older ones.

(Good Engineering Practice)

11) *Inhibitor Injection Nodes for Berth Piping*: There are no inhibitor injection nodes (a fitting that permits the injection of corrosion inhibitor into a pipe) or internal coupon monitoring locations on the Tanker Berth loading piping. The nearest coupon monitoring locations to the berth loading arms are upstream of the last expansion loops. Alyeska began an integrity inspection program in 2002 to directly assess the over-water and loading arm (API570 Class I) piping using RT and UT. These are the present modes of assessment to monitor the berth loading arms. No mention in the reports is made of any corrosion concerns being found at the loading piping, however, a corrosion failure at the berths would spill product directly into the water.

(See Recommendations, Item #3)

12) *CP Dip Tube Test Stations*: CP dip tube test stations or coupon test stations are used at select locations at the *VMT* where instant off potentials are difficult to obtain through conventional CP monitoring methods. CP coupons are installed in the East and West Tank Farms, and East Metering for the piping in those areas. Additionally, whenever a test station is called for at a dig site, a dip tube test station is installed. This is good engineering practice, as it allows for the accurate recording of CP potentials without having to synchronously interrupt the current from several rectifiers.

(Good Engineering Practice)

13) *RSPA Waiver*: RSPA Waiver P-95-1W; Notice 2 attached to MP-166-3.03 requires that Alyeska will continue an excavation and inspection program of insulated above-to-below ground non-insulated DOT jurisdictional pipe. Inspections were to begin in 1995 and continue on a frequency based on the corrosion found. The maximum interval was not to exceed 5 years. The waiver granted a variance to Alyeska from the requirement to provide cathodic protection to thermally insulated transition piping. The RSPA waiver applies only to DOT jurisdictional piping. The inspection work has been performed through the course of many years under different projects at the *VMT*. There have been numerous AG/BG transitions inspected throughout the *VMT* on non-jurisdictional piping. With respect to the DOT jurisdictional piping from East Metering to Tanks 1 & 3 which is the 36” relief headers, there have been 5 AG/BG transition investigations as follows; one (1) in 1992, one (1) in 1998, two (2) in 2000 and one (1) in 2001. The conditions of this waiver have been met.

(Good Engineering Practice)

14) *Weld Pack Corrosion*: There is no program in place to specifically inspect or target insulated girth weld (weld pack) locations on above ground piping in facilities (process piping). This practice takes place typically on uncoated cross country lines or cross country lines with only uncoated tie-in welds from pipe laying operations. The A/G insulated pipe at the *VMT* is coated, and opportunistic visual inspections are performed whenever the insulation is removed for a project or other reason. If concerns are found (corrosion or mechanical damage) then appropriate actions are taken. While weld pack corrosion is an issue for uncoated thermally insulated lines, the thermally insulated lines at the *VMT* are coated and opportunistic inspection has shown weld pack corrosion to not be an issue.

(Good Engineering Practice)

15) *PIT Program Piping Inspection*: Insulated PIT Program piping is being initially inspected with RT densitometry to screen for >20% wall loss. UT follow up is then done on these areas. Evidence in the 2002 report suggests that the RT densitometry is not wholly reliable for measuring wall loss, though the numbers suggest that it errs on the conservative side. Specifically:

a. At Berth 4, 2 of 25 sites inspected showed densitometry wall loss estimates of greater than 20%. UT follow-up showed 5% to 19% wall loss in those areas. (2003 report, page 10).
b. At Berth 5, 7 of 31 sites inspected showed densitometry wall loss estimates of >20%. UT follow up showed the range of wall loss for these sites to be 2.8% to 24.5% (2003 report, page 10).

UT Spot checks are not currently done, though it would be desirable to check areas of 15% to 19% wall loss (by RT densitometry) to verify the accuracy of the RT wall loss estimates.

It should be noted that the qualitative RT densitometry method does provide a valuable method for initial screening of long stretches of insulated pipe. The costly alternative would be to select a piping run, strip insulation, select several likely areas for gridding, and then UT the grids. The RT screening method allows more pipe to be examined for less money.

(Good Engineering Practice, and Also See Recommendations, Item #5)

16) *LRUT Evaluation*: Alyeska has been evaluating the guided wave LRUT, but with the present technology level the data is not quantitative, and is barely qualitative. The RT densitometry technique seems to provide the best screening method for covering large runs of pipe and providing potential problem areas for UT prove-up. The LRUT program was discontinued at the end of 2003 due to the inaccuracy of the technique.

(Good Engineering Practice)

17) *Calculation of Corrosion Rates*: Corrosion rates are calculated by assuming a constant linear corrosion rate and dividing the mils (thousandths of an inch) lost by the number of days. The first inspection of a site yields a rate that assumes corrosion began from day one of service, which is not necessarily the case but is better than nothing. Alyeska does not calculate the rate until the second inspection, and uses the mils lost in the interval divided by the number of days in the interval. This yields a more representative rate, but calculation of a rate at the initial inspection at least yields a figure upon which to base an initial RSTRENG half-life.

Page 11 of the 2003 report states that a 9.7% wall loss was found at the Tank 8 manifold, along with external CUI. The extent of wall loss was determined using UT. The corrosion rate was not determined because this was an initial baseline investigation. For initial inspections, it would be wise to consider using the time-in-service to determine the initial corrosion rate, even though this assumes corrosion began at day one. This at least gives something for future comparison.

In 2003, East and West Meters Prover Piping had 28 locations inspected, most with scattered pitting at the bottom and sides. A maximum corrosion rate of 3.1 mpy was observed. Again, it would be useful to state the date of the previous inspection along with the corrosion rate. If the site has no previous inspection date, then the corrosion rate should be calculated based on total time in service.

(See Recommendations, Item #6)

18) *Tank 14 Over Bend*: The 2003 report mentions a "recurring" 10 mpy corrosion rate noted at the over bend from B header to Tank 14, determined by UT. The location was discovered in 1999 and the RSTRENG half-life indicated that re-inspection was not due until 2003. The current remaining wall thickness was determined by UT to be 0.380" (0.462" nominal wall). This illustrates the utility of the PIT Program for flagging reinspection of known corrosion locations for ongoing monitoring.

(Good Engineering Practice)

19) *Over Bend Inspection Program*: In 2003, an analysis of all over bend piping segments was undertaken to determine if the 2004 scope should be expanded to perform inspections of other tank over bends. It was determined that inspection of more over bend sites was justified and Alyeska is looking at more of them for 2004 PIT Program scope.

(Good Engineering Practice)

20) *BWT Inhibitor Injection and Coupons*: Inhibitor injectors and internal coupons are planned for placement in the BWT skimmed oil lines. An inhibitor injector point is being installed in the ORB on a suction line and at Tank 80, under project Z429. The same project is also replacing selected piping in the ORB.

(Good Engineering Practice)

21) *Removal of Corrugated Metal Piping at Over Bends*: Removal of corrugated metal piping (CMP) surrounding the over bends at the East Tank Farm headers was completed in 2003. This was an historical problem that was causing CP potentials in this area to diminish due to electrical contact of the pipe with the bare surface of the CMP. The removal of all the CMP was an involved project spanning several years.

(Good Engineering Practice)

22) *Operator Qualifications for DOT Regulated Piping*: 49 CFR Part 192, Subpart N and 49 CFR Part 195, Subpart G requires that personnel performing covered tasks (such as corrosion investigation) on DOT piping be operationally qualified. Most piping on the *VMT* is not DOT covered piping, so the Operator Qualification requirements do not apply in those cases. However, most if not all the technicians that work at the Terminal also work on DOT covered pipeline facilities and are OQ'd. The Office of Pipeline Safety (OPS) reviews the training records during the annual standard inspection to ensure compliance.

(Good Engineering Practice)

23) *Industrial Wastewater Sewer System*: The IWWS is a drain system to the BWT. It runs from the periphery facility areas (tank farms, pressure washing bays, mechanic shops, etc.) to the industrial sump systems and from there to the BWT for processing. The maximum pressure is 5 psi, and the pipes are cast iron with mechanical joints (bell and spigot or screwed joints). Line sizes run from ½" to 20" and since the individual joints are not electrically bonded, it is not possible to apply CP to this system. The smaller bores are galvanized on the inside and outside, but there is no coating aside from that.

The IWWS is not regulated piping and is not required to be tested. As a matter of good engineering and business practice, Alyeska does test the whole system pneumatically or hydrostatically over the course of five years. Failures have been seen in a few sections every year since 2002, and these sections are usually repaired the following summer. The bulk of the problems have been in the Power/Vapor subsystems and repair work is ongoing.

(See Recommendations, Item #19, and Objective #1, Item #5)

PWSRCAC OBJECTIVE NUMBER 3

Verify that APSC has procedures in place to identify and to address non-tank corrosion issues."

Alyeska's System Integrity Monitoring Program Procedures document (MP-166) outlines the procedures for pipeline maintenance and monitoring, from data collection to requirements for data retention and storage. The relevant sections of MP-166 for this study are listed and summarized below. Title 49 Code of Federal Regulations, part 195 (49 CFR 195) deals with hazardous liquids pipelines, and the MP-166 document exists to ensure that Alyeska's corrosion monitoring program is in compliance with 49 CFR 195. The 49 CFR 192 which deals with natural gas pipelines is also mentioned in MP166. By convention, material not covered in 49 CFR 195 is defaulted to 49 CFR 192. The regulations for gas pipelines are generally more demanding than those for liquid pipelines.

The intent of Alyeska's in-house specifications and procedures are to follow the guidelines and requirements of the federal and ASME codes. Alyeska's length of time for record retention meets or exceeds the federal requirements. Research performed for this project indicates that Alyeska specifications and procedures do follow the guidelines of the regulations and codes satisfactorily. From our observations, the specifications and procedures appear to meet or exceed the regulatory requirements.

The Alyeska Work Management System (AMS) has several work processes that provide assurance that codes, regulations, and standards are followed. AMS-004-01, "TAPS Engineering Guidance Manual," provides standard guidance to Alyeska and contract engineers performing design work. Alyeska periodically employs AMS-019, "Assessment Process," and AMS-020, "Internal Audit Process" to assure compliance with the AMS-004-1 process and MP-166 procedures.

In addition, the OPS and the JPO conduct annual inspections of facilities and pipe that fall under OPS and JPO inspection, providing an independent verification of compliance.

Alyeska's Internal Procedure and Guidance Documents

MP-166-3.01, "Corrosion Inhibitors, Pump Stations and VMT"

This procedure outlines the use of chemical inhibitors in critical crude oil system piping to prevent internal corrosion.

The Integrity Management (IM) Team is specifically tasked with and responsible for complying to the requirements of 49 CFR 195.579, "What must I do to mitigate internal corrosion?" Specifically, the team selects chemical inhibitors and formulates the corrosion treatment plan. MP-166-3.01 requires records of the chemical injection logs and annual corrosion report to be kept for the life of the pipe (LOP), which complies with the federal code.

IM Engineers make the call to determine new coupon locations and inhibitor injection points. Several criteria are used to determine the test locations. API570 provides guidelines for location selection and these guidelines are considered along with historical problem spots on similar pressure legs. The chemical inhibitor supplier consultant also provides input based on their experience with similar systems. Individual asset requests relayed from the "technicians on the floor" are also used to try and anticipate problem areas. The IM team chooses the inhibitor chemical and initial injection quantity in consultation with the chemical supplier. Injection quantities are then optimized based on the internal corrosion monitoring coupon data. Alyeska maintains drawings showing internal coupon and inhibitor injection sites.

Occasionally, missed dosages happen due to suppliers not making deliveries on time or are due to operating conditions that may prohibit access to a location. The nature of an inhibitor is to build up a passivated film on the pipe interior and the tendency of this film to remain effective over time is called "persistence". 49 CFR 195.579(b)(1) requires that "If you use corrosion inhibitors to mitigate internal corrosion, you must use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect." Doubling up on the next inhibitor dose hopefully increases the persistence level, and is certainly better than doing nothing, and is an attempt to meet the intent of the code.

The chemical inhibitors are biocidal to a certain extent, which means it exterminates microbile bugs that can cause corrosion. Therefore, piping from the DAF cells to the BTT to the seaside discharge is not inhibited, since that water is eventually released into the bay.

MP-166-3.02, "Internal Corrosion Coupon Program"

This procedure describes the use of internal corrosion monitoring coupons to monitor corrosive conditions inside crude oil piping systems and to monitor the effectiveness of chemical inhibitors used to control internal corrosion.

The Integrity Management Team is specifically tasked with and is responsible for complying with the requirements of 49 CFR 195.579, "What must I do to mitigate internal corrosion?" 49 CFR 195.579(b)(2) requires that if you use inhibitors, you must use coupons or other monitoring equipment to determine the effectiveness of the inhibitors. Specifically, the team selects monitoring sites, maintains the coupon database, analyzes coupon data, prepares the annual facilities report on same, and recommends action items to the asset. They also provide the coupon schedule to the crews, review the contractor laboratory analysis procedure(s), and oversee the coupon installation and removal. Alyeska maintains drawings showing internal coupon and inhibitor injection sites.

The contractor laboratory provides the analysis data in lab data sheet and Excel spreadsheet format. The IM team checks one against the other to verify the correct data have been recorded. The team then reviews the data to determine corrosive conditions and makes recommendations for corrosion control. Corrosion control may take the form of greater inhibitor dosage, more coupon installations, UT inspections, and pipe replacement.

MP-166-3.01 requires results of the coupon analyses and annual corrosion report to be kept for the life of the pipe (LOP), which complies with federal code.

Alyeska maintains the *VMT* Corrosion Coupon Watch List to track aggressive coupon corrosion rates and publishes it in the annual report. Criteria for maintaining the watch list requires adding coupon locations that exhibit an "average corrosion rate" other than "low corrosion rate" and removing coupon locations that subsequently exhibit an "average corrosion rate" of "low" for the next two consecutive corrosion pulls. Corrosion rates are defined by NACE RP0775-99 and are shown in the following table.

Table 1: Qualitative Categorization of Carbon Steel Corrosion Rates (from NACE RP0775-99)

Category	Average Corrosion Rate (mpy)	Pitting Corrosion Rate (mpy)
Low	<1.0	<5.0
Moderate	1.0 – 4.9	5.0 – 7.9
High	5.0 – 10.0	8.0 – 15.0
Severe	>10.0	>15.0

The "average corrosion rate" defined in RP0775 is determined from coupon weight loss over time. Typically, one strives for a "low" "average corrosion rate" and this is the driver behind Alyeska's inhibition program. The "pitting corrosion rate" is calculated from increase of pit depth over time. RP0775 states, "Time to pitting onset varies, and pit growth may not be uniform. Therefore care should be exercised in applying calculated pitting rates to projected time-to-failure." Hence, the "average corrosion rate" is a better indicator for general corrosivity and "low" (<1 mpy) is the sought after rate.

MP-166-3.03, "Facility Corrosion Integrity Monitoring"

This procedure describes the methodology, organizational responsibility, documentation, and reporting requirements for piping integrity testing and monitoring of non-mainline facility piping and related equipment. The scope includes, but is not limited to, *VMT* hydrocarbon (crude, diesel, gasoline, turbine and jet fuel), vapor recovery, and ballast water treatment (BWT) piping.

The Integrity Management SME is responsible for establishing inspection criteria for the piping systems, integrity analysis, records and database maintenance, and making repair recommendations to Asset Management. The Asset Manager is responsible for inspection funding and field implementation of corrosion monitoring and control.

This procedure is basically a summation of the monitoring procedures that deal with inspection and corrosion evaluation on the belowground and process piping. References to Alyeska Master Specifications are cited, which govern methods of integrity inspections, external corrosion monitoring, determining special inspection locations, determining the corrosion control program inspection schedule, determining fitness for service, and corrosion control improvements.

The PIT program inspections are modeled after API570 sec. 6.2 recommendations and the IM team makes the final determination for new thickness measuring locations (TML's). Criteria for determination of new thickness measuring locations comes from API570 guidelines, as well as examining previous data in the same and similar pressure legs for indications of potential problem areas. Individual asset requests, relayed from the "technicians on the floor" are also used to try and anticipate problem areas. Input from the technicians is a valuable resource since they may notice configurations that are not readily discernible to an engineer looking at isometric and P&ID drawings. A 60% wall loss in a steam condensate line in the power/vapor facility was discovered due to an asset request for inspection.

The reinspection intervals for existing sites are determined by the Corrosion Inspection Database (CID) spreadsheet. Flags or indicators pop up automatically based on the half-life interval (minimum span) or the most stringent API570 recommended interval (maximum span) for piping class one (five years for visual and internal inspection). The half-life interval is half the calculated time to reach 80% wall loss. The API570 interval, 5 years, is the maximum span between inspections. The CID is a valuable tool in the spring for building the work scope for the coming summer. Corrosion half lives are not typical; rather they are unique to the conditions. Typical trouble spots are:

1) Horizontal Runs At Bottom of Pipe (BOP), Low Fluid Velocity, and Low Relative Elevation

2) Horizontal Runs At BOP, Low Fluid Velocity, and Upstream of A Weld Seam

3) Outside Radii of Elbows, With Higher Fluid Velocity

4) Downstream of Reducers Where Cavitation From Turbulence May Occur

5) Stagnant Flow Areas, Such As Deadlegs

6) Downstream of Pump Discharges

The above list is not exhaustive, and corrosion rates will be affected by the velocity, sediment content, temperature, and chemical nature of the product. Once the corrosion rate is established, the half life will be dependent on the nominal wall thickness. Typically, tees, reducers, valves, and elbows will have heavier walls than the steel pipe of the same schedule.

MP-166-3.05, "Cathodic Protection Monitoring Data Analysis"

This procedure provides criteria and instructions for CP monitoring data analysis to determine whether cathodic protection levels are adequate**.**

The IM Engineering Supervisor is responsible for seeing that the requirements of the procedure are performed in a professional manner and within the allotted time frames. The field engineer collects/compiles/computes the field data into usable engineering data.

This procedure provides the analysis procedures for cased road crossings, criteria for interrupted and uninterrupted CP systems, critical bond stations, and metallic structures in seawater. It also outlines the method of reporting for all CP data, along with reporting on the current status of the prior year's recommendations and work orders. Evaluation and criteria for acceptable levels of cathodic protection are referenced to the applicable NACE standards.

MP-166-3.07, "Bi-monthly Inspection – Impressed Current Cathodic Protection Services"

For the *VMT* this procedure directs the bimonthly inspection process for ICCP systems per 49 CFR 192.465(b) and 49 CFR 195.573(c).

The IM engineering supervisor is responsible for assigning a responsible corrosion engineer and ensuring that the procedures are performed within the specified time frame.

The corrosion engineer's field work entails reading, inspecting, and testing the ICCP rectifiers. The engineer then records, files, analyzes and reports on the rectifier and bond data. If damaged or inactive units are discovered in the field, the status and recommended corrective action is immediately reported to the engineering supervisor.

MP-166-3.09, "Valdez Marine Terminal Cathodic Protection Systems"

This procedure describes the steps required to monitor CP levels of various cathodically protected structures in the *VMT*, and applies to berths, docks, tank bottoms, and buried piping.

The IM Engineering Supervisor is responsible for seeing that the requirements of the procedure are performed in a professional manner and within the allotted time frames. The field engineer collects/compiles/computes the field data into usable engineering data.

This procedure provides the analysis procedures and also outlines the method of reporting for all CP data, along with reporting on the current status of the prior year's recommendations and work orders.

Alyeska Master Specification B-511, Pump Station and Terminal Pipe Investigation

This is an internal *APSC* specification describing the requirements for in-service inspection and data collection for field corrosion analysis of ASME B31.3 (process piping) and B31.4 (liquid hydrocarbon transportation piping) piping systems.

The process outlines accounts for initial visual inspection of external corrosion and, at the discretion of the CFE, gridding and UT inspection of any surface corrosion of greater than 10% wall loss. B31.3 piping is to be analyzed per B31G (or RSTRENG, at the discretion of AIM) and B31.4 piping is to be analyzed in accordance with RSTRENG methods (See *APSC* Master Spec B-512). The CFE is required to have successfully completed the Alyeska Site Engineer Training Program.

Non-corrosion related defects are evaluated per ASME B31.4 criteria and repaired per *APSC* MR-48, section 2. The evaluation is carried out in stages by the CFE. Primary to the process is the coating visual evaluation. After completion, the pipe is stripped and grit blasted, and a visual examination is performed on the pipe surface. Corrosion types and locations are identified, along with any existing mechanical damage. Subsequently, UT grid locations are laid out at the direction of the CFE.

General direction for identification of grid areas may be provided by the project package and the CFE will also use good engineering judgment to choose likely areas of internal corrosion. Additionally, areas of external corrosion with pit depths exceeding 10% of nominal will be gridded unless directed otherwise by the CFE.

B-511 establishes minimal longitudinal and circumferential grid dimensions, and if numerous internal pits exceeding 10% nominal wall are found, then the longitudinal grids are extended. The CFE documents all corrosion and mechanical findings on the PIR and CIR investigation sheets. The CFE performs remaining strength evaluations with RSTRENG methodology and records same in the CID. If the evaluation does not meet field evaluation criteria, then the results are forwarded to AIM for further evaluation. Pipe recoating, reinsulation, or excavation backfill cannot be done until the site is released by the CFE. Complete records of the investigation are retained in the CID and CDM.

Alyeska Master Specification B-512, Pipeline Corrosion Evaluation Procedures

This is an internal *APSC* specification that allows the user to determine whether a given segment of piping that has sustained some metal loss needs to be repaired, replaced, or safely left in service. The ASME B31G and RSTRENG theory and methods of analysis are covered, and acceptable and unacceptable conditions are defined.

A flowchart is provided to determine the necessity and extent of required repairs. The flowchart establishes when OCC is to be contacted (buckled or leaking pipe, or operating pressure restriction required), when AIM is to be contacted (mechanical damage, remaining wall less than 50% nominal, circumferential corrosion, or calculated allowable pressure is less than P72).

Alyeska Master Specification B-513, Terminal Vapor Recovery System Pipe Investigation Specification

This is an internal *APSC* specification describing the requirements for in-service inspection, data collection, and field corrosion analysis of the Valdez Marine Terminal Vapor Recovery System Piping.

Piping is selected for inspection by the Responsible Engineer. Initial sample inspections are to include 3% of the subject piping. Inspection of subject piping shall be increased to 10% in the event of >50% of the selected locations showing >20% wall loss, any pitting found >50% wall loss, or any pitting found to exceed the corrosion wall allowance.

The piping systems are separated into pressure legs or segments. As a general rule, 3% of carbon steel piping per leg, and at a minimum one UT grid per leg for stainless steel piping is inspected. As the program has progressed, the percent of total piping having been evaluated is in excess of the percents noted above due to new sites being added to the scope of program activity. The PIT program has all grid sizes and number of sites documented and can account for total percent of system wide piping inspected.

MR-48, Trans Alaska Pipeline Maintenance and Repair Manual

This all encompassing manual describes maintenance and repair procedures for almost everything on the TAPS from bridge decks to piping. Evaluation is not considered.

SUR-10, Surveillance/Repair Procedure for Belowground Piping or Equipment Integrity Management

This *APSC* procedure describes the Integrity Management program for the opportunistic examination and evaluation of existing piping or belowground equipment exposed during excavations. It describes the roles and responsibilities of groups within the *VMT* and provides guidelines for implementation, including scope of opportunistic investigations, documentation requirements, and ensures the implementation and completion of subsequent repairs pursuant to the evaluation of the piping or equipment.

AMS-004-01, TAPS Engineering Guidance Manual, TAPS Engineering Guidance Manual

This internal manual provides guidance for engineers working on design modifications on TAPS. The document provides direction for everything that must be considered when assembling a project design package. It is a lengthy document, but is mentioned in this report because the review process is relevant.

The work package must undergo extensive reviews before it is issued for construction (IFC). Engineering reviews by the relevant disciplines ensure that the work is designed according to applicable codes and standards. The inspection attributes (part of the package) ensure that the work in the field is done according to the applicable codes and standards. Governmental agency comments on any part of the package must be resolved prior to IFC.

AMS-019, Assessment Process

This document provides a method for evaluating the suitability, effectiveness and efficiency of individual processes, programs, work activities, and the Alyeska Management System. Executives, managers and supervisors initiate internal assessments to proactively improve business or to determine the cause of ineffective performance. Drivers for assessment may be the result of an incident, management directive, or performance indicators such as an audit findings, compliance violations, inspection results, lessons learned, or forecasts.

The document is germane to this report to show that AIM engineering is cognizant of the codes, recommended practices, and timelines for compliance and good engineering practice. The necessity of adherence to same is reinforced by the self policing of the assessment process.

AMS-020, Internal Audit Process

The internal audit process provides Alyeska Management and the Owners with an independent appraisal of the integrity and adequacy of Alyeska's internal system of control. The scope of this internal process does not include external audits from the DOT, JPO, etc. Internal controls provide reasonable assurance regarding the achievement of operational efficiency, financial reporting reliability, and compliance with applicable laws and regulations. Alyeska has established certain reporting relationships to ensure that the internal audit staff is free of organizational pressures that might limit their objectivity. Frequency of internal audit reviews and activities are based on the risk to exposure inherent to business activities.

This process provides a further self policing action that ensures AIM engineering adheres to applicable codes and recommended practices.

PWSRCAC OBJECTIVE NUMBER 4

"Verify that maintenance schedules are sufficiently frequent to address the recurring non-tank corrosion issues."

API 570: API 570 provides recommended classes (Class 1-3) based upon service, location, vaporization, flammability, etc. The line classes at the *VMT* cover the full range of API 570 line classes. The API 570 categories and inspection recommendations are as follows:

1) Vapor Recovery Piping - Class 3: Once every 10 years UT the thickness or per the corrosion ½ life, whichever is less, and every 10 years perform a visual inspection.

2) BWT Piping – Class 1: Once every 5 years UT the thickness or per the corrosion ½ life, whichever is less, and every 5 years perform a visual inspection.

3) Firewater – Excluded or optional with respect to regulatory requirement, however, Alyeska takes the initiative through annual programs and projects to include the firewater system piping in their inspections.

4) Crude – Class 2: Once every 10 years UT the thickness or inspect in accordance with the corrosion ½ life, whichever is less, and every 5 years perform a visual inspection.

5) Diesel – Class 3: Once every 10 years UT the thickness or inspect in accordance with the corrosion ½ life, whichever is less, and every 10 years perform a visual inspection.

6) Gasoline - Class 2: Once every 10 years UT the thickness or inspect in accordance with the corrosion ½ life, whichever is less, and every 5 years perform a visual inspection.

7) Piping Over Water – Class 1: Once every 5 years UT the thickness or inspect in accordance with the corrosion ½ life, whichever is less, and every 5 years perform a visual inspection.

Inspection intervals for all system piping at the *VMT* meets or exceeds the API Class 1 inspection intervals as identified in Table 6-1 of API 570, for visual external and thickness measurement inspections every five years. API 570 was developed for the petroleum refining and chemical process industries, and is recognized in the industry as the standard inspection, repair, alteration, and re-rating code for in-service metallic piping of such industries.

Most buried piping at the *VMT* receives cathodic protection. The cathodic protection rectifiers are read on a bi-monthly basis by the *VMT* technicians. Rectifier data is also recorded during the summer CIS work. These intervals satisfy both per 49 CFR 192.465(b) and 49 CFR 195.573(c).

All DOT jurisdictional lines (disputed and non-disputed) are monitored for cathodic protection levels by CIS annually per 49 CFR 192.465 and 49 CFR 195.573. The remaining crude, fuel, and recovered crude are surveyed at 100% each year. The FW piping is surveyed at a rate of 20% per year, even though there is no regulatory requirement. The exception to the above is the piping under substantial concrete (about 1% of the *VMT* piping) and bell and spigot Industrial Waste Drain piping, which is not available for CIS.

Regarding the inhibitor dosing schedules and coupon pull schedules, 49 CFR 195.579(b)(1) requires that "If you use corrosion inhibitors to mitigate internal corrosion, you must use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect." 49 CFR 195.579(b)(2) requires that if you use inhibitors, you must use coupons or other monitoring equipment to determine the effectiveness of the inhibitors. API 570 and NACE RP0775-99 provide guidelines for placement of inhibitor injection quills and internal coupons for effectiveness, and good engineering judgment must be applied since all piping systems are different. There are no hard and fast rules and this type of program is by definition dynamic.

Integrity Management injects inhibitors on a bi-weekly schedule. The bulk inhibitor injection run occurs every summer, usually in July or August, and is used to flood stagnant deadlegs with inhibitor. The coupons are pulled twice each year, with intervals not to exceed 7.5 months. At present, this program appears to be a sound one.

PWSRCAC OBJECTIVE NUMBER 5

"Verify that appropriate standards regarding non-tank corrosion issues are in use at VMT and that these standards drive appropriate maintenance and inspection schedules."

The following standards, regulations and codes are referenced in MP-166. The Monitoring Program Procedures document refers to the NACE recommendations for preferred practice standards and technique.

NACE RP0775-99, "Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations."

This NACE recommended practice provides the standard for determining corrosion rates from internal test coupons. Coupons are used to evaluate the corrosiveness of various systems. High corrosion rates on coupons may be used to verify the need for corrective action, however low rates cannot be used to declare a cessation of corrosion. If an inhibitor program is initiated and subsequent data indicate that the corrosion has been reduced, then the information can be used to assess the effectiveness of the mitigation program.

The procedure provides recommendations for:

1) Coupon Preparation and Field Handling.
2) Laboratory Procedure for Post-Exposure Cleaning and Weighing.
3) Calculation of Corrosion Rates.
4) Installation of Coupons (Shapes, Mounting Brackets, Location In System).
5) Considerations to Be Made When Interpreting Corrosion Data.
6) References for Further Discussion.

NACE RP0169-02," Control of External Corrosion on Underground or Submerged Metallic Piping Systems."

This NACE recommended practice presents procedures and practices for achieving effective control of external corrosion control on buried or submerged metallic piping systems. It contains specific provisions for the application of cathodic protection to existing bare, existing coated, and new piping systems. Also included are procedures for control of interference currents on pipelines.

This procedure provides recommendations for:

1) Determining the need for external corrosion control of a structure.

2) Designing piping for external corrosion control, specifically:
    a. Electrical Isolation.
    b. Coating Selection.
    c. Consideration of Appurtenances.
    d. Casing Design.
    e. Test Station Design.

3) Methods for evaluating in-service field performance of existing coatings.

4) Criteria for cathodic protection.

5) Design of cathodic protection systems.

6) Installation of cathodic protection systems.

7) Control of interference currents.

8) Operation and maintenance of cathodic protection systems.

9) Maintaining external corrosion control records.

10) Determining contingent costs of corrosion and corrosion control.

11) References for further discussion.

API 570, Piping Inspection Code

This API Code covers inspection, repair, alteration, and re-rating procedures for metallic piping systems that have been in-service. It was specifically developed for the petroleum refining and chemical process industries, and is the accepted industry standard for same. It limits itself to not be used in conflict with any prevailing regulatory requirements, even though the federal requirements reference it as the standard.

The Code Defines:

1) It’s general application and definition of classes of piping systems, along with excluded and optional piping systems.

2) Responsibilities of the owner/user.

3) Inspection and testing practices, specifically:
    - Inspection for specific types of corrosion and cracking.
    - Types of inspection and surveillance.
    - Inspection of specific appurtenances like valves, welds, in-service flanges, etc.

4) Frequency and extent of inspection.

5) Inspection data evaluation, analysis, and recording.

6) Repairs, alterations, and rerating of piping systems.

7) Inspection of buried piping.

8) Inspector certifications.

9) Inquiry format for interpretations of the code.

10) Acceptable repair format for patches, and welding of same.

ASME B-31.3, Chemical Plant and Petroleum Refinery Process Piping Code

This ASME code sets forth engineering requirements deemed necessary for safe design and construction of new pressure piping (metal, non-metal, and non-metal lined) typically found in petroleum refineries and terminals, and chemical process plants. It is a complete design "bible" and describes every possible consideration for:

1) Mechanical design criteria.

2) Requirements for components, joints, flexibility, materials, and standards for components.

3) Fabrication, assembly, and erection.

4) Inspection, examination, and testing.

5) Welding materials, techniques, and required qualifications.

The code is for new piping systems, but is referenced extensively by API 570, which deals with existing and in-service piping systems.

ASME B-31G, Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B-31 Code for Pressure Piping

This ASME code provides a method for evaluating pipe that has experienced metal loss through corrosion, and determining a conservative value for a de-rated MAOP. Strength analysis takes into account the depth and longitudinal length of single arrays of pitting, and provides a means to calculate an allowable pressure level.

The formulae in this manual were empirically derived from several hundred specimens of actual corroded pipe removed from service, comprising of all types of defects. The specimens were pressure tested to failure, and mathematical expressions were developed to describe general defect behavior.

49 CFR 192, Transportation of Hazardous Liquids by Pipeline

This part of the Code of Federal Regulations prescribes the minimum safety requirements for pipeline facilities and the transportation of gas. Natural gas pipelines typically operate at much higher pressures than liquids lines, and the corrosion requirements of this section of the code have historically been more exacting than 49 CFR section 195. This section is commonly referred to for hazardous liquids pipelines in the event a corrosion-related instance is not adequately covered in section 195.

49 CFR 195, Transportation of Hazardous Liquids by Pipeline

This part of the Code of Federal Regulations prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids. The accepted (by Alyeska and the DOT) DOT jurisdictional piping at the *VMT* is the incoming mainline, relief piping, and the two breakout tanks. DOT also asserts control over the A & B header piping past the east tank farm down to west metering, the A & B headers from west tank farm down to west metering, and the header piping from west metering down to the berth 4 and 5 loading arms. Alyeska is contesting that, and the matter is presently under adjudication, with a decision expected by the end of 2004.

The pertinent parts relating to corrosion at the *VMT* are as follows.

1) Each operator must have and follow a DOT approved written qualification program for personnel working on covered piping.

2) Each buried or submerged pipeline must have an external coating for external corrosion control.

3) Each buried or submerged pipeline must have cathodic protection per NACE RP0169-96, with external test leads for corrosion control monitoring.

4) When a buried pipeline is exposed, it must be examined for external corrosion. Any corrosion found must be “chased” to determine the total extent.

5) Buried piping must be CIS’d every year.

6) Rectifiers and interference bonds must be read on a bi-monthly basis.

7) Internal corrosion must be investigated and mitigated using internal corrosion coupons and chemical inhibitors. Coupons must be pulled and examined at least twice per year.

8) If a joint of pipe is removed, the internal surface must be examined for corrosion.

9) Pipelines exposed to the atmosphere must be coated.

10) Onshore exposed pipe must be visually inspected every 3 years, and offshore (over water) every year.

11) Corroded pipe must be repaired or be pressure de-rated. Remaining strength of corroded pipe may be assessed using ASME B31G or RSTRENG calculations.

12) Records of the above must be maintained for at least 5 years.

18 AAC 75.080, Facility Piping Requirements for Oil Terminal, Crude Oil Transmission Pipeline, Exploration, and Production Facilities

This part of the ADEC regulations describes piping requirements for the non-DOT piping at the *VMT*. The parts that relate to corrosion mitigation at the *VMT* are as follows.

1) Buried steel piping containing oil must be maintained in accordance with a corrosion control program approved by the department.

2) The piping must undergo a corrosion survey.

3) The piping must be carefully examined for deterioration any time a section of buried line is exposed for any reason.

4) The piping must undergo an additional examination and corrective action to repair the damaged pipe and control future corrosion if corrosion damage is found.

5) Buried or insulated transfer hoses or piping must be annually tested with hydrostat or another method approved by the department.

6) Aboveground piping and valves must be visually checked for leaks or damage during routine operation, or at least monthly.

7) Piping supports must be designed for seismic stability, corrosion control, and minimizing chafing.

8) Appropriate measures must be taken to protect aboveground piping from damage by vehicles.

The appropriate standards regarding non-tank corrosion issues are in use at VMT and these standards appear to be driving appropriate maintenance and inspection schedules

PWSRCAC OBJECTIVE NUMBER 6

"Verify that permitted (either by standard or custom) levels of non-tank corrosion are acceptable and that inspection schedules are sufficiently frequent and thorough such that all existing corrosion will be identified and will not exceed the permitted levels."

The data, supplied by Alyeska, indicates there are some corrosion issues at the *VMT*, and that these are being addressed in the form of inspection, monitoring, piping repair, and construction of additional CP systems. The reports and interviews indicate that good engineering practice is being practiced, and the codes and recommended practices are being used.

The objective asks if all existing corrosion will be identified and no corrosion will escape detection to exceed permitted levels. It is reasonable to say there is a strong likelihood that corrosion problems will be identified and will not exceed permitted levels. Alyeska's internal procedures and specifications are written to follow the codes and adhere to good engineering practice. Internal and external audits are administered to provide reasonable assurance of the same.

Alyeska has presented sufficient information to demonstrate that its corrosion management of non-tank corrosion issues at the Valdez Marine Terminal is an aggressively managed program. This suggests a long-term commitment to preserving facilities for future use and sensitivity to environmental consequences of failure to do so. Recommendations and observations contained in this document should therefore be viewed as opportunities for incremental improvement with respect to meeting regulatory requirements and industry practices and standards.

APPENDIX 1 LIST OF ACRONYMS/NAMES

A/G	Above Ground
ADEC	Alaska Department of Environmental Conservation
AIM	Alyeska Integrity Management
AMS	Alyeska Work Management System
API	American Petroleum Institute
APSC	Alyeska Pipeline Service Company
ASME	American Society of Mechanical Engineers
BD	Berthing Dolphin
B/G	Below Ground
BOP	Bottom of Pipe
BTT	Biological Treatment Tanks
BWT	Ballast Water Treatment
CDM	Corrosion Data Management System
CEI	Coffman Engineers Inc.
CFE	Corrosion Field Engineer
CFR	Code of Federal Regulations
CID	Corrosion Information Database
CIS	Close Interval Survey
CMP	Corrugated Metal Pipe
CP	Cathodic Protection
DAF	Dissolved Air Flotation
DOT	Department of Transportation
FW	Fire Water
ICCP	Impressed Current Cathodic Protection
IFC	Issued For Construction
IM	Integrity Management
IWWS	Industrial Wastewater System
JPO	Joint Pipeline Office
LOP	Life of the Pipe
LRUT	Long Range Ultrasonic Testing
MAOP	Maximum Allowable Operating Pressure
MD	Mooring Dolphin
MLD	Main Loading Dock
MP-166	Alyeska's Integrity Management Monitoring Program Procedures document
MOV	Motor Operated Valve
mpy	Units of Corrosion Rate, one "mil per year" is 0.001 inches per year
NACE	National Association of Corrosion Engineers
OCC	Operations Control Center
OQ	Operator Qualification
OM&S	Oil Movements and Storage
OPA-90	Oil Pollution Act of 1990
OPS	Office of Pipeline Safety
ORB	Oil Recovery Building
P72	The pipe operating pressure that corresponds to a stress level of 72% of SMYS

APPENDIX 1 LIST OF ACRONYMS/NAMES

PIT	Pipeline Integrity Testing
RSPA	Research and Special Programs Administration
RT	Radiographic Testing (X-ray)
RWT	Remaining Wall Thickness
SME	Subject Matter Expert
SMYS	Specified Minimum Yield Strength
SOP	Standard Operating Procedure
SPOC	Single Point of Contact
SR	Strategic Reconfiguration
TAPS	Trans Alaska Pipeline System
TML	Thickness Measuring Location
UT	Ultrasonic Testing
VMT	Valdez Marine Terminal

APPENDIX 2 DEFINITIONS

Anodeflex – A linear impressed current polymer anode that is proximate to the pipe and provides specific local protection.

Cathodic Protection – A method to protect a metallic structure from corrosion where a voltage is applied to a buried or submerged (typically steel) structure by means of an anode. The structure's potential is changed so as to turn the structure into a cathode, thereby arresting corrosion on the structure.

> The level of protection is measured by comparing the structure's potential to a stable reference such as a Cu/CuSO4 or Ag/AgCl reference cell. Protective levels are defined as those more negative than -0.850 volts with respect to the Cu/CuSO4 cell, or -0.800 volt with respect to the Ag/AgCl cell, after the IR drops due to protective current have been taken into account. The IR drops are accounted for by placing current interrupters on the surrounding sources of CP current. Instant-OFF potentials (no IR drop) can then be measured on the structure. Protection is alternatively defined as a 100mV or greater negative shift in the structure's potential from the native (unprotected) potential of the structure.

Corrosion Inhibitor – A chemical injected into the product stream inside a pipe that aims to reduce corrosion by altering the chemistry inside the pipe.

Dip Tube Test Station – A test station that provides a dip tube for positioning the reference cell near the pipe in order to help minimize IR drop error.

External Corrosion Coupon Test Station – An external coupon of the same material as the structure, and electrically continuous with the structure, so as to receive CP current. The purpose of the coupon is to allow evaluation of the structure's cathodic protection at a particular locale. The connection can be opened at the test station and the instant-OFF potential of the coupon measured. In this manner, the local level of protection can be determined without having to interrupt all the local sources of CP current.

Internal Corrosion Coupon - An internal coupon of the same material as the structure, mounted inside the pipe. The coupons can be removed while the pipe is in service, and a corrosivity estimate is then made according to the immersion period and level of observed pitting and weight loss on the coupon. Separate calculations are used to assess pitting rate and general corrosion rate.

PIT Program – The pipeline integrity testing program that includes annual RT and UT testing on selected piping legs. Locations are selected based on asset requests, historical problems on similar configurations, and API570 guidelines. Inspection intervals are at calculated half-life, with the interval not to exceed 5 years.

RSTRENG – A modified criterion developed by Battelle Laboratories for evaluating the strength of corroded pipe with large areas of metal loss and areas of discontinuous pitting. This method requires a more detailed mapping of the areas of metal loss, but eliminates some of the conservatism built into the B31G method of analysis. Use of RSTRENG allows pipe to safely remain in service that may have been otherwise condemned by B31G. Both methods are approved for use by 49 CFR 192 and 49 CFR 195.

Strategic Reconfiguration – Alyeska's current initiative to streamline operations system wide. *VMT* changes under consideration include removal of one or more of the crude tanks, BWT tanks, firewater pipes, crude pipes, and berths. Power source alternatives are also being considered, as well as conversion of the fire protection system from pumped salt water to gravity-fed fresh water.

APPENDIX 3 REFERENCES

Alyeska Documents

2002 *VMT* Facility Corrosion Monitoring Program Annual Report

2002 *VMT* Rectifier Operation and Maintenance Summary Annual Report

2002 *VMT* Facility Corrosion Monitoring Annual Report

2002 Valdez Marine Terminal Cathodic Protection Systems Annual Report

2003 Valdez Marine Terminal Facility Corrosion Monitoring Annual Report

Drawing D-50-CP1, "Overall Cathodic Protection System Site Plan"

Drawing D-50-M806, sheets 1-5, "Valdez Marine Terminal Chemical Injection Monitor and Sample Points"

MP-166-3.01, Corrosion Inhibitors - Pump Stations and *VMT*

MP-166-3.02, Internal Corrosion Coupon Program

MP-166-3.03, Facility Corrosion Integrity Monitoring

MP-166-3.05, Cathodic Protection Monitoring Data Analysis

MP-166-3.07, Bi-monthly Inspection – Impressed Current Cathodic Protection Services

MP-166-3.09, Valdez Marine Terminal Cathodic Protection Systems

Alyeska Master Specification B-511, Pump Station and Terminal Pipe Investigation

Alyeska Master Specification B-512, Pipeline Corrosion Evaluation Procedures

Alyeska Master Specification B-513, Terminal Vapor Recovery System Pipe Investigation Specification

MR-48, Trans Alaska Pipeline Maintenance and Repair Manual

SUR-10, Surveillance/Repair Procedure for Belowground Piping or Equipment Integrity Management

AMS-004-01, TAPS Engineering Guidance Manual, TAPS Engineering Guidance Manual

AMS-019, Assessment Process

AMS-020, Internal Audit Process

National Association of Corrosion Engineers (NACE) Documents

NACE RP0775-99, Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations

NACE RP0169-02, Control of External Corrosion on Underground or Submerged Metallic Piping Systems

American Petroleum Institute (API) Documents

API 570, Piping Inspection Code

American Society of Mechanical Engineers (ASME) Documents

ASME B-31.3, Chemical Plant and Petroleum Refinery Process Piping Code

ASME B-31G, Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B-31 Code for Pressure Piping

U.S. Department of Transportation (DOT) Documents

49 CFR 192, Transportation of Hazardous Liquids by Pipeline

49 CFR 195, Transportation of Hazardous Liquids by Pipeline

State of Alaska Administrative Code Documents

18 AAC 75.080, Facility Piping Requirements for Oil Terminal, Crude Oil Transmission Pipeline, Exploration, and Production Facilities

APPENDIX 4 EVALUATION OF MARINE STRUCTURES

Berths 4 and 5 (Main Loading Docks, Berthing Dolphins, and Mooring Dolphins)

- Cathodic protection potentials meet or exceed criteria for protection.
- Diver visual inspection of MLD's, BD's, and MD's revealed negligible corrosion.
- Diver UT spot checks of member wall thicknesses indicate thicknesses are within nominal.
- Diver UT flooded member detection indicated no flooded members.
- Diver visual inspection revealed coating systems are in good condition.
- Diver visual inspection of welds revealed no suspect welds.
- Visual inspection of the fenders revealed severely corroded bolts that secure the fenders. Failure of the bolts could result in the fenders falling in the water and possibly damaging the oil booms. The 2003 report recommends replacement of the bolts.
- Visual inspection of the horizontal chains revealed significant corrosion and some damage. In some places the chains are abrading the coating. The purpose of the chains is unknown and the 2003 report recommends removal of the chains.

  (See Recommendations, Items #17 and #18)

Berth 1

- Cathodic protection potentials meet or exceed criteria for protection.

Berth 3

- Cathodic protection potentials meet or exceed criteria for protection.

Small Boat Harbor

- Cathodic protection potentials meet or exceed criteria for protection.
- One existing old rectifier was replaced with four new smaller units to allow greater control of current discharge in the small boat harbor systems.

Crowley Tug Dock

- Cathodic protection potentials meet or exceed criteria for protection.